Q3 2014 REPORT

Seven Generations Energy Ltd. ("7G" or the "Company") (TSX: VII) is pleased to report its third quarter 2014 operating and financial results.

HIGHLIGHTS

- Third quarter production averaged a record 35,820 boe/d, an increase of 406% from the third quarter of 2013 and a 49% increase over the second quarter of 2014.
- Record funds from operations for the third quarter 2014 of $106.3 million or $0.48 per share on a diluted basis. On a per share basis, this is a 1,500% increase over the third quarter of 2013, and a 55% increase over the second quarter of 2014.
- Achieved operating netbacks of $35.79 per boe in the third quarter of 2014, a 56% increase over the third quarter of 2013.
- During the third quarter of 2014, increased active drilling rig count to ten rigs. Rig-released ten wells with an average horizontal lateral length of approximately 2,838 meters.
- Subsequent to the third quarter of 2014, 7G completed an initial public offering ("IPO") of common shares with net proceeds to the Company of approximately $882 million. As a result of the IPO, the Company has access to liquidity in excess of $1.4 billion.
- During the third quarter of 2014 independent evaluator, McDaniel & Associates Consultants Ltd., updated the Company's Total Best Estimate Contingent Resources to 728 million barrels gross (637 million barrels net) oil equivalent ("MMboe") and Total Best Estimate Prospective Resources to 1,096 MMboe gross (986 MMboe net). The corresponding before tax net present values, using a discount rate of ten percent per annum, are $4.6 billion for Total Best Estimate Contingent Resources and $4.2 billion for Total Best Estimate Prospective Resources.

	Three months ended September 30			Nine months ended September 30		
	2014	2013	% Change	**2014**	2013	% Change
OPERATIONAL						
Production						
Oil and NGL (bbl/d)	**20,869**	3,253	542	**15,527**	4,904	217
Natural gas (MMcf/d)	**89.7**	23.0	290	**67.3**	19.5	245
Total (boe/d)	**35,820**	7,084	406	**26,739**	6,505	311
Liquids ratio	**58%**	46%	26	**58%**	50%	16
Product prices (1)						
Oil and NGL ($/bbl)	**66.33**	60.52	10	**70.16**	57.09	23
Natural gas ($/Mcf)	**4.62**	2.64	75	**5.14**	3.38	52
Operating expense ($/boe)	**4.32**	6.91	(38)	**4.83**	6.86	(30)
Transportation expense ($/boe)	**3.89**	3.82	2	**4.65**	4.03	15
Operating netback ($/boe) (2) (3)	**35.79**	23.00	56	**37.74**	25.99	45
FINANCIAL ($000s, except for per share amounts)						
Revenue	**165,501**	23,692	599	**391,828**	68,681	471
Funds from operations(4)	**106,294**	4,780	2,124	**226,430**	27,159	734
Funds from operations per share – diluted(5)	**0.48**	0.03	1,500	**1.02**	0.16	538
Net income (loss)	**30,482**	(955)	3,292	**75,572**	(8,533)	986
Net income (loss) per share – diluted(5)	**0.14**	(0.01)	1,500	**0.34**	(0.05)	780
Capital investments, net of dispositions	**328,423**	142,185	131	**740,596**	396,090	87
Adjusted working capital (3)(6)	**67,700**	129,586	(48)	**67,700**	129,586	(48)
Senior notes (7)	**784,000**	412,120	90	**784,000**	412,120	90

(1) Prices exclude realized gains and losses on risk management contracts.
(2) Operating netback is calculated on a per-boe basis and is defined as revenue (including realized hedging gains and losses plus third party income) less royalties, operating expenses and transportation costs.
(3) Operating netback, funds from operations and adjusted working capital do not have any standardized meaning prescribed by International Financial Reporting Standards (IFRS) and, therefore, may not be comparable with the calculation of similar measures presented by other entities. Please refer to the Non-IFRS Financial Measures section of this report for additional information.
(4) Excludes interest and financing charges.
(5) On September 8, 2014, the Company amended its articles of incorporation to divide the issued and outstanding Class A Common Shares on a two-for-one basis. The share split has been reflected in the condensed interim statements on a retroactive basis. Only dilutive stock options and performance warrants have been included.
(6) Adjusted working capital excludes unrealized risk management contracts and deferred credits.
(7) Senior notes as reported represent US$700.0 million principal converted to Canadian dollars at the closing exchange rate for the period end.

MESSAGE TO THE SHAREHOLDERS

November 12, 2014

Dear Shareholders

Well, we just completed launching our IPO. The Toronto Stock Exchange thinks of us by our ticker symbol, "VII." Now we embark on a continuous auction process, constantly open for offers, constantly in the public eye and constantly getting a report card from the investment world. As you are probably fully aware we launched in a difficult time. Through the marketing period during the second half of October, West Texas Intermediate, North America's benchmark crude oil price, traded 16% below the average for the calendar year to that point. Some of our most similar competitors (Paramount, NuVista, Trilogy, Tourmaline, Antero, Rice, EP) traded on average 30% below their yearly peak price during the period. With our lead underwriters advising your Board of Directors, we launched with the thesis that our Company has important differentiating features which enable it to stand out in our industry and among our peers in a down market. There is no better way to scrutinize and evaluate a business strategy than subjecting it to hundreds of analysts and portfolio managers just at a time when profound change is being contemplated by the market's experts.

Therefore, it seems appropriate to share with you some of the questions that we heard in multiple meetings and our answers to them. However, before we embark on that adventure, please let me advise you of two relevant matters:

1. The key risks for the Company are described in the Prospectus which was filed with the offering and is available on sedar.com. I am not going to address them herein. Rather, the reader is referred to that document and should consider this commentary only as additional, broad insight into general strategic matters.
2. Matters of overall business strategy are the domain of the Board of Directors which considers issue by issue as they arise and also conducts an overall review of the Company's business strategy about once per year. The next such review is scheduled to occur next month. The last one was about a year ago.

While marketing the IPO and addressing strategic issues during investor meetings, I relied on the guidance received from the Board of Directors since we first financed in 2008 and my own views as Chief Executive Officer and a Director. With the Board's last long-term strategic review about a year behind me, I may find that when the Board next meets on this matter that our views have departed slightly. After all, eight directors bring views from a diversity of training and experience to our Board. In the past, my views have often been deflected by the guidance of our Board, so in stating them here I am reflecting a personal view that is only a personal view and subject to significant revision before adoption by the Board.

COMMODITY PRICES

The first category of strategy questions focused on commodity prices. Recurring questions included:

1. How do lower commodity prices affect our liquidity, our capital plan and our ability to be self-sustaining?
2. Does it make sense to continue to grow given the low commodity prices?
3. How long and how deep do we think the commodity price depression will be? What is our plan based on?
4. How do we see the expansion of our gas and liquids markets?
5. What threats to expansion and growth of markets do we see?
6. Why do we think we are well-positioned to take on expansion of the gas and liquids markets?
7. What about condensate, specifically? Is that a market about to be flooded?
8. Are we concerned about competition in the Chicago market from other sources of gas such as the Utica and Marcellus?
9. If WTI remains below $80 will oil sands projects stop/slow thereby reducing condensate demand?
10. Why are both size and high quality (as reflected in a low threshold price) important?

In answer, let me first say that we are not commodity markets experts nor do we engage any expert services for their views on commodity prices. We don't have an expert derived price forecast and we don't represent ourselves to have insights into the magnitude and duration of any market trends. Our strategy has never been to get the price forecast right and then make investment decisions on that basis. Rather, our strategy has always been to be among the lowest cost new supply of the products that we produce in the marketplace. We have endeavoured to be near the toe of the supply cost (also known as threshold price) boot. In this regard, we are also not experts on projects beyond our own and rely on analyst reports, which we see from time to time, that plot the supply cost or threshold price of various large projects in the North American market. (Note for example that the definition of supply cost varies from analyst to analyst but it may be the commodity price required to achieve a profitability threshold such as a 10% before tax internal rate of return on half cycle drilling investment). In that regard, comparing our own analyses of our projects to the plots of supply costs for other projects provided by the analysts, we are generally satisfied that we have among the lowest cost new supplies of gas and, by separate analysis and comparison, hydrocarbon liquids in the North American market.

When we contemplated the size of the IPO ($CDN 810 MM) we specified the amount our analyses suggested would be required (using also reasonable, easily managed debt) to get the Company to the point where cash flow would cover all expenses including debt servicing and repayment and the capital program. Underlying that analysis was the key assumption that we would not expand our business significantly through discovery or acquisition. Between the time that we prepared that forecast and the time that we started marketing the IPO, the 2015 forward strip for West Texas Intermediate crude oil dropped by about $US 10/bbl. Including the benefit of hedges that we have in place, we expect an oil price drop of that magnitude to reduce our funds from operations by about $CDN 50 MM (consisting of a $CDN 80 MM reduction in funds from operations and $CDN 30 MM in hedging gains) in 2015. We have identified a number of measures to accommodate that kind of cash flow drop, among them:

1. Reducing discretionary capital expenditures while maintaining capital deployment sufficient to meet our firm transportation, processing and marketing contracts,
2. Using more debt including longer term, high yield debt as market and internal circumstances allow,

3. Achieving some of the upside potential that we hope to realize given the novelty of our project and a common tendency for resource play operators to find ways to improve profitability with optimization efforts applied to the repeated well and facility construction activities associated with those projects.

We also increased our gross IPO financing by the amount of the Underwriter's over-allotment option, approximately $CDN 122 MM.

So, clearly, if our modeling is right, and we don't expand the business, creating the need for even more capital, we have the financial capacity to continue to develop at a rapid pace. Some investors asked us if we thought that was the right thing to do. The answer lies in our view of our asset and the market. We believe we have a high quality asset, an asset near the toe of the supply cost boot and an asset that can make a return on development of new supply at prices too low for nearly all other projects. But the market is not completely efficient relative to its theoretical ability to drive down prices until there is just sufficient supply. The accessibility of markets (sales contracts, physical transportation and processing infrastructure) gets in the way. We think that the Company is exposed to a high risk that markets will be increasingly difficult to access and supply side infrastructure in areas rich in low cost resources (such as the northwest Alberta/ northeast British Columbia Montney) will fill up. So, in order to achieve cash flow self-sufficiency we think the Company's best choice is to aggressively pursue markets. In that regard we were lucky to contract space on the Alliance pipeline, getting the midstream service providers to allow us to ramp up over four years into capacity that is available in just one year. So our Alliance transportation and our Aux Sable rich gas premium contracts dictate our minimum pace but we will be looking aggressively to add more capacity and to accelerate, within our ability to properly manage any such acceleration, the pace that might be required to capture more market access.

How much market access do we need? The answer to that question is determined by the size that our recoverable resources at any given threshold price are ultimately determined to be. Our independent reserve and resource evaluator's 50 percent confidence categories of Total Proved Plus Probable Reserves, Best Estimate Contingent Resources and Best Estimate Prospective Resources suggest a combined deliverability of about 1¼ Bcf/d of gas using the evaluator's price forecast. In order to be able to assure that we have access to markets, we have to be able to underpin (contract to a midstream service provider) sufficient capacity so that the service provider will build whatever market access infrastructure we may need. At this point we don't know what the future market for our gas beyond the contracted 500 MMcf/d will be, but we are very actively exploring alternatives varying from pipeline capacity to Canadian or American Pacific coast LNG terminals to pipelines into American consuming hubs and, if required, on to US Gulf Coast LNG facilities. The point is, that in order to cause such infrastructure to be built, to contract the tariffs required, large volumes over long periods might be required. Right now, we do much of our strategic planning assuming that we need at least 2 Bcf/d for about 20 years. That is a gross estimate of the minimum amount of gas supply for economic midstream infrastructure to be built that would allow rich gas to reach export terminals on the Pacific coast. That ultimate target level guides our decisions about short term growth with the objective of capturing market share to reach a point of cash flow self-sufficiency. If we are successful in the short term, then we should have the resources to expand by the next step. The next step, the big step, which hopefully fully matches our resources to a market, may see our production grow to something like 15 times the present rate of gas delivery (4 times the rate we currently have contracted). That is also why we are satisfied with a short term contract (expiring in 2022) with Alliance and Aux Sable. We may need that gas deliverability to support a larger project and it may be impractical to grow to a level that supports both the existing Aux Sable arrangement and whatever new arrangement is required to reach the full potential of our lands. In a perfect world, Aux Sable and Alliance might be partners in our market solution and we can roll the existing arrangement into the agreements for the broader solution. What seems quite clear though, is that producers in our region without both the high quality, as indicated by low supply cost, and high quantity resources to commit supply to major infrastructure expansion, bear a significant risk of very long queues for market access. [A side note of this thinking that you may find interesting is that gas market infrastructure is needed in most cases to produce oil. For any given amount of gas market, all else being equal, maximum revenue can be gained with rich gas or oil (the solution gas requiring the gas infrastructure). Thus excess gas capacity to market needs could lead to a situation where growth of domestic oil production is limited by limited solution gas markets.]

One worthwhile comment on gas prices arises from 7G's own success with reducing drilling costs and increasing production (and, possibly recovery). We hope these measures will reduce our supply cost. We think that many of our competitors are also experiencing success in their supply cost reduction efforts. With significant supply cost reduction in the industry there might be downward pressure on gas prices.

As for liquids, we see a wide range of views on condensate demand as a result of oil sands expansion. One expert analyst recently suggested that aggressive expansion of oil sands production, even if only the most likely projects go ahead, may result in the need for more than a quarter of a million barrels per day of additional condensate supply. On the other hand, some people argue that delays and cancelations in oil sands projects due to challenges with both economics and social licence may evaporate any incremental need for condensate. Further, rail back-hauls of diluent and the reversal of the Cochin pipeline both add competing supply to the Company's existing condensate market. These factors make prediction of the short term market for condensate difficult.

Often the big picture sheds light on what brackets a longer term outlook. It seems to me that, at least for the next decade or so, global transportation infrastructure will require liquid hydrocarbon fuels. In North America, if we use less heavy oil we will have to use more lighter feedstock. The level of demand for refined products seems more predictable than the source that the refining industry will use to meet the demand. Presently, supply meets demand in North America by using a large amount of heavy oil and bitumen from Canada – our refineries are set up to produce the refined product slate that we consume from the feedstock that we supply. If we reduce the amount of heavy oil supply, we will need to increase the amount of an alternative – that alternative may, with capital investment in refinery modification, be condensate directly. So, the really big picture, looks like the market will almost certainly need the condensate – depending on such matters as heavy oil prices and the outcome of the public debate regarding carbon dioxide emissions, some portion of the bitumen market may be in question.

What market situations will turn out to be the best choices for our full potential? We don't know yet. We are in early stage discussions with midstreamers and buyers as to the following types of alternatives:

- LNG with or without LPG (refined natural gas liquids) exports from the west coast of Canada or the USA,

- Increased gas delivery into the US Midwest marketplace through capturing existing or building additional pipeline capacity and from there into the US market through the existing and contemplated US transportation and processing infrastructure including the possibility of accessing the Gulf of Mexico for LNG export,
- Additional liquids gathering and transportation capacity from the Grande Prairie region to the Edmonton region.

The situation is complicated by the ability of other suppliers to flood markets that we may consider accessing. We need to be confident that we can compete on the basis of cost of delivered supply to the market (production costs and transportation tariffs) with other supplies considering the same market. Therefore, our goal is to accumulate gas deliverability capacity sufficient to underpin the infrastructure investment required and to compete in any market that we choose to access. We can't ensure success in this endeavor but failing to build capacity, failing to test and define the size and quality of the resource on our own lands, failing to optimize our wells and development plan (aiming to reduce our own supply cost) and failing to consider alternatives will most likely result in stagnation at the currently contracted 500 MMcf/d level. In other words, we can't guarantee success in finding profitable access to expanded markets but we can guarantee failure if we don't position ourselves to be able to go to the market with confidence that we have enough gas of sufficient quality to compete for the markets.

ACQUISITIONS

The foregoing answers to the series of questions on strategy with respect to commodity markets are intimately related to our view on acquisitions. The commonly asked questions were:

1. Are we interested in acquiring more land?
2. If we are interested in acquiring more land, what type of land are we looking for?
3. Are we looking at corporate level mergers and acquisitions or just property level transactions?

We have a lot of land. To be of interest, more land would have to enhance our value (while considering the very long development inventory we have using a fairly conservative view about the upside of our undrilled Montney land and our unproven zones). However, considerations that might make acquiring additional land interesting include:

1. We would like to maintain our quality and to continue focusing development capital to assets near the toe of the supply cost boot whether the assets produce lean gas, rich gas, or light or heavy oil.
2. We are interested in low cost rich gas or solution gas that could add scope to our existing ability to underpin large scale infrastructure expansion.
3. We would like to be able to use existing midstream relationships to test and commence development of the assets and to piggy back, where possible, off of existing midstream contracts until we more fully understand the size and quality potential of the new assets in the context of our overall market thrusts.
4. Direct offsetting expansion of our existing land base can result in improved economics as we would usually expect to be able to drill longer, more profitable, wells with a more extensive and continuous land base.
5. In order to offer the current owner an attractive price we would like to see what 7G's perceived advantage is relative to the current owner in terms of development economics. This might arise from our focus on the GP region including our operations headquarters with its operating and technical skill focused on that region, our extensive road and gathering and processing infrastructure, our access to capital and market access.
6. Property with excess contracted market access, beyond the capability of the assets to economically meet, both physically and contractually, might be appealing – provided, of course, the vendor's expectations reflect the uneconomic status of the vended assets.

This list of criteria is intended to be restrictive. The perfect acquisition would have all 6 features. Generally, the less that potential acquisition lands possess of the above features, the less attractive they are to us. Given that risks and values are properly assessed and accounted for in the transaction, we have no preference as to corporate or property transactions.

CORPORATE FINANCE

There were also a series of commonly asked questions relating to the Company's finances:

1. Why do we own our own infrastructure? Would this type of investment best be served in a "spin off" company or owned by a mid-streamer?
2. What is the Company going to do to access sour processing infrastructure?
3. What is our view on the use of debt?
4. How much 'sustaining' capital is required to offset declines versus 'growth' capital?
5. What is our hedging strategy?
6. Who do we see ourselves the most like corporately? What is the best current benchmark? Who would we most like to be like in the future?
7. Why would we IPO in such an adverse market for oil and gas commodity prices and the downward momentum on the share prices of many of our competitors? And the related question: Who do we see as being most interested in our IPO issue given the market circumstances?

Owning infrastructure is not directly important to us. Being able to differentiate in innovative design and use of infrastructure, in nimbleness to change to evolving technology, commodity markets and our evolving understanding of our assets and being able to change the pace of growth to adapt to market circumstances are all important. We ramped up our drilling program in our very high quality upper and middle Montney "Nest" lands last year. The results of the new wells plus the additional data from our oldest wells gave us the confidence to contract more of the then available capacity on Alliance. We were able to make the decision and schedule the production ramp up with minimal lead time because we are in control of the building of our plants. The very high liquid gas ratios associated with our "Nest" area gas has necessitated the use of artificial lift. Application of artificial lift was facilitated by distributed compression. Distributed compression led to advantages with separate liquid and gas gathering. Separate gas gathering enables us to operate our gathering system at high pressure and thereby get much higher rates for any given pipeline size. Because we compress our gas in the field we have the option to design our refrigeration plants for higher operating pressure. Our arrangements with Aux Sable and Alliance enable us to deliver rich gas into the pipeline. We can remove liquids from a slip stream of the gas and re-inject lean gas from a smaller refrigeration plant. The contracted delivery specification to Alliance will change with the initiation of our new contracts in about a year. Until then we will be able to get by with a smaller plant which has enabled us to defer capital. We will need a second plant, but if we tie it in to what is now the far end of our main gathering trunk line we can essentially double the capacity of that trunk line which is an expensive line because its construction involved crossing two deep river valleys. These are a string of related examples of the nimble evolution of a differentiating technical design and rapid growth that was afforded to us because we own our gathering and processing infrastructure.

Our “Nest” is sweet requiring only minor (offsite treated) absorbent sweetening. Depending on how much gas we end up contracting and the timing of additional markets the “Nest” drilling inventory could last 7G more than a decade. Much of the gas being developed by others in our region is sour. We expect that our neighbors will contract the available sour gas processing capacity in the region as they develop their sour resources while we focus on our sweet “Nest.” The bigger picture is that the liquids rich Montney and Duvernay formations in the broader region are among the continent’s lowest cost supplies of gas. The market is likely to call upon them to be developed over the coming one to two decades. During that development, long before the region reaches its full potential production capacity, more H_2S extraction plants will be required. We will be prepared to build or to dedicate our gas to a midstream processor, whichever is the best alternative for Seven Generations at that time. There may arise a time when spinning out our facilities in a separate vehicle is the best choice.

The Board has not established a policy on debt. Rather, the amount of bank debt that the Company should take on has been a matter of Board discussion each time the Company has revised or drawn on its bank lines. In deliberating on the matter, the Board has considered the base production of the Company and its sensitivity to the decline rate at the time, commodity prices, and netbacks. We have also considered the nature of the suite of capital investment immediately in front us: How much is low risk “Nest” drilling to be tied into existing facilities versus how much is for testing new areas and new zones or for building or upgrading gathering and processing facilities? While the Board recognizes the equity return multiplying effect of the prudent use of debt, it also acknowledges the volatility of netbacks and the risks associated with the commodity production business. In consideration of what we could do if circumstances turn against us over a reasonable range of events, the Board has determined how much debt is comfortable whenever the question has arisen. As a director, I have always been conservative on this matter. Perhaps it is age. I am reminded of the joke about aeronauts: “there are old pilots and bold pilots but there are no old, bold pilots.”

In a similar manner, but looking at a longer term, the Board has had similar deliberations whenever we have considered the high yield debt market.

The sustaining capital question is an interesting one to which there is no straight answer. As soon as our original wells were completed and tied in we produced them as hard as our gathering system would allow. This resulted in about three quarters decline in the production rate over the first year. So if we were producing at the full capacity of our wells and we were operating in this mode in the early stages of the ramp up of our production, we would have to replace about three quarters of our wells each year to hold production flat. Presently that would be about 30 wells or 5 rigs (40 to 60 percent of our fleet this year) just to hold production at what it has recently been. That is one extreme. At the other end of the answer to the question, we have found, as have many of our tight gas developing competitors, that producing the wells more slowly results in a much flatter decline profile. Even though wells that are choked back start from a lower initial rate, the practice results in more cumulative production (than the aggressive production alternative) in as short a period as about half of a year. We don’t have enough data to really determine exactly what our longer term well decline profile might be (that is an upside that we often discussed on the road). In any case, the decline profile resulting from constrained flow (known as “slowback”) is, typically, much flatter. Further, with either production strategy, aggressive or slowback, after the first 3 to 6 years the wells in the competitors’ projects that we have examined (we don’t have any wells that old, ourselves) tend to level off at very low decline rates. Over time this low-decline, tail production from multi-year drilling programs stacks up and long-in-the-tooth operations tend to have a very flat base production to which a much smaller percentage of wells are added annually to maintain production. We expect that we will transition over the coming few years from about 40 to 60 percent of our drilling activity being required to hold our production rate level to a much lower percentage.

Incidentally, this mature property phenomenon is another reason to aggressively ramp up to capture market share in the short term. An operator, adding a small percentage of new wells every year with half cycle economics can more readily satiate any new demand than one that has to drill to offset steep, early stage declines and has to underpin new infrastructure. The now grossly over-supplied gas business is becoming more like the coal-fired power generation business wherein operators might have huge reserves but limited mining and generating capacity and are limited by their markets for electricity. Like this coal-fired power business, the gas industry may be transitioning from a business evaluated on the basis of its reserve value to a business evaluated on the basis of its revenue. Like the electricity business, market share may become the constraint to growth.

The Board of Directors has a hedging committee that meets from time to time to determine hedging strategy. Over recent quarters that strategy has been to hedge a large percentage of our established base production out over the coming three to four quarters and taper off to no hedges beyond a year and a half. Since we make hedging decisions on the decline profile of current production and we have been growing by 100 percent or more per year we have ended up with only a small percentage of our forecast total production hedged. Since much of our future revenue is expected to result from capital yet to be spent and we don’t want to hedge revenue streams that we have yet to realize we have only minimal coverage of our capital program, but we have way more than sufficient production hedged to cover the servicing costs on our high yield debt.

Who among our competitors do we see ourselves most like? Wow – that is a tough question – staying on top of all of the things to consider for our own Company is a tough job. I can’t say that I know any other company well enough to say this is the one that I like the most. There are things that I like about certain competitors:

1. One competitor is well known for its management and governance. It has thoughtful and thorough investor communications. It seems to position very well for some of the best new technologies and resource types as they emerge and it is thoughtful and methodical in testing to establish leading technical strategies to exploit its resources. We get a lot of unsolicited employment interest from the industry but not much from this company.
2. Another competitor has grown rapidly and maintained tight control on its finances, approaching the market to fund each increment of growth. Like Seven Generations, this company was a little later than most entering the tight gas business but also like us, through their own combination of luck and geological skill, they have positioned in quality plays.

3. On the road, more than one investor compared us, due to our use of technology to position in the best plays and to enhance value and our culture of innovation, to a leading US independent, a technical leader in the tight resource sector.

As we go forward, with the guidance of our Board, our public company culture will mature. Given the chance, I will select our role models buffet style, picking what we think to be the best of each of a few companies and, perhaps, adding some features of our own. With feedback from our shareholders, hard work, good decisions and good assets, we hope to become the Company that others emulate.

Why did we choose to launch our IPO in a down-trending market for both oil and gas commodities and our competitors' stock? Upon advice of our lead underwriters our Board contemplated the alternatives and came to the decision to proceed. Here are key reasons:

1. We cannot predict when or if the market will recover, but our projects yield good returns at the lower commodity prices.
2. We have take-or-pay contracts that require aggressive growth to fill.
3. We took on our contract obligations out of concern that the market is over-supplied and available market opportunities might vanish over a short period of time but, even though we are committed to well beyond our current production, we may, with aggressive but managed growth, be able to capture a larger market share while there are still markets to capture.
4. Other companies, in some cases without sufficient capital to execute their programs, in other cases without markets, may have high quality assets with a good strategic fit to ours that we can acquire if our performance is strong through the down cycle.
5. We have always positioned to be a low cost developer, at the toe of the supply cost boot. Markets such as the current market emphasize the quality of our asset base and, perversely, may help to sell our stock.

We were surprised by the breadth and strength of the interest in our stock in the down market. We had expected the following to be factors in whether investors chose to place an order:

1. Is the investor, even through a different portfolio, already an investor? If so, with the recent growth in our stock price, does that investor already own as much of our stock as they would like?
2. How much specific knowledge of our area does the investor have? Is the investor already an investor in our offsetting competitors? Has the investor toured our operations?
3. Does the investor tend to buy and hold, possibly seeing the current environment as a counter-cyclic buying opportunity?
4. Does the investor tend to take positions on all or most significant Toronto Stock Exchange listings?
5. Is the investor in a situation to be constantly reminded of gas shortages in some other parts of the world (e.g. Asia and Europe)?

I don't know what our underwriters expected but I expected more focused interest coming largely from investors that were already in our stock and from large, biased to long holding, Canadian funds. Those funds were interested but so was a much broader array. We were pleasantly surprised with the amount of orders from Europe, Asia and, especially, the USA.

MANAGEMENT

There were quite a few recurrent questions about the management team. Most investors pointed out that the results to date (capture of much of the best part of a leading asset, rapid growth while improving efficiency, strong share value growth) suggest a strong team but they wondered how we planned to maintain the momentum. This is difficult to answer other than to say the team is generally extremely motivated to take the Company to the next milestones: the 500 MMcf/d contracted production and the identification and capture of the next market growth tier. When our Board raised the concern that many of the founders would have a lot of personal wealth and may decide in the future that they don't want to work so hard we did a number of things:

1. We put in a meaningful retention plan.
2. We asked each founding manager and executive to consider succession and to hire a person that would be capable of assuming his/her role. We were careful to indicate that we were not encouraging anyone to leave. Rather we appealed to their sense of professionalism in providing for the Company in case, for any reason, they are unable to continue to serve the Company in their current capacity (we used the hit-by-a-bus cliché).
3. We asked key employees to position their own role and their staff's responsibility for continued rapid growth.

This has largely been done. Now we face the task of acculturating the new hires to 7G's high energy, thorough, technically rigorous, we-don't-have-a-department-for-that-do-it-yourself style. We described our drilling department's remote operating centre in Calgary wherein we continuously monitor all of our rigs with expert drilling engineers. We described our Grand Prairie office with its 20 plus engineers managing tie-ins and debottlenecking and how we put an engineer on every frac.

I pointed out that the same team who acquired the assets at the heart of the liquids rich Montney, drilled the first highly successful vertical well into it in 2009, went on to consolidate the land base and raise the money to delineate and commercialize it and has now grown production by 4 times in the last 12 months and expects to double the yearly average production next year over this year. That same team is still with us but is now augmented largely by hand-picked experts recruited directly by or referred to the original executive. Our staff levels have roughly doubled in the past year and we need to continue to grow but we will work hard at maintaining the aspects of our culture that have contributed to our success.

UPSIDE POTENTIAL

Finally, there were often questions about potential upside value. These included:

1. How do we see technology being part of our plan?
2. How far along are we as to what we predict the mature state of technology for our business to be?
3. What is the low hanging fruit in terms of technology application to improve economics?
4. How do we see ourselves positioning relative to our competitors and relative to the opportunity with technology?
5. Aside from technology, what low risk practices can be adopted with the goal of improving value?
6. What do we like and what concerns us about our secondary target zones and the regions of our land that have not been recognized as reserves by our independent reserve evaluator?

As described in our Prospectus, we've enjoyed enormous success in reducing drilling cost and improving early production performance (leading to an optimistic outlook for better ultimate recovery). Most of the drilling improvements were off-the-shelf but a few were new technology. In any case, nearly everything that we have tried has demonstrated an ability, under some circumstances, to add value. This high success ratio suggests that the technology is immature. We can expect to continue to deliver a high success rate with our tests. When asked to describe where we are by a baseball analogy, we would say that we are far enough into the game to see that it is going to be high scoring with a lot of success posted to the scoreboard, but we are not so far into the game that we can see the end or that we are starting to fear losing an inning – we're in the middle of the third inning.

For me, the amazing thing about resource plays (coal bed methane, oil sands, tight gas and oil) is that once a play and technology that applies to it are identified, the operator is motivated to pursue even small value gains on each early well because benefits that are identified often apply with low risk to large future well inventories.

A priority for us right now is to determine the optimal well spacing / frac spacing / frac size configuration. We have been testing various well spacings assuming that three layers of wells will be required to optimally exploit the Montney (but that assumption is up for eventual validation as well). The single layer well spacings that we have tried range from 160 metres interwell spacing which is equivalent to 10 wells per mile to 400 metres which is equivalent to 4 wells per mile. At 4 wells per mile we observed no interference between wells. At 5 wells per mile we were able to observe communication between wells while fraccing with no discernable evidence of communication during production of the wells. At 10 wells per mile we observed responses at offset wells during both fracture injection and during production. Even though the 10 wells per mile test wells show evidence of communicating, they still, through the first few months, have performed as well as nearby wells that have no parallel offsets. All of these tests were done with 1.5 tonnes of proppant per metre of frac interval. We have noticed marked improvement of production performance with frac sizes up to 1.5 tonne per metre. Limited testing with larger sized fracs to date leaves us wondering if we can make even further gains with frac size. The goal with increased frac size is to increase production rate and/or recovery or to facilitate the further spacing of wells without decreasing the value of the land. Land, after all, is the limiting factor. At this stage we don't know whether we will get the best overall total value with a lot of wells with large fracs or less wells with very large fracs. It would seem very lucky indeed if our first guess turned out to be optimal and we cannot improve on our present standard frac size and well layout.

There are a lot of other technical choices to be optimized, including but not limited to frac fluid, frac design, proppant type, proppant concentration, liner design, pad size (including maximum well displacement – the distance that the well is deviated sideways to space it from other wells before it is turned horizontally which determines the width of a region that can be drilled from one pad), a new friction reducing mechanical device that members of our drilling team designed, improved bit designs, improved drilling mud systems (including underbalanced drilling), larger drilling clusters to dilute the costs associated with rig moves and to minimize the amount of surface land use and more efficient separators to separate the NGLs, gas and condensate at lower cost. Our highest level policy statement calls on all of our staff to differentiate, to find ways to contribute within their scope that make the Company different and better. One of the results is that we have a culture of innovation. Nearly everyone is brimming with ideas for improvement. I expect this cultural element to persist, adding shareholder value, for years to come.

Although technology is part of our DNA, I don't see a lot of benefit in secrecy. I would rather openly share with competitors who, like we do, invest a lot into experiments to learn better ways. Hopefully by sharing with companies that we perceive to be similarly motivated to add value through technology we can reduce the cost of innovation for all participants and we can accelerate the learning for all. I see little reason to share practices with companies whose competitive niche is to focus on cost reduction and chose to apply only well-established technologies but I would really like to put our technical team in a room with the technical teams of some of the industry's technology leaders.

There are lots of things that we can do to improve economics that involve minimal technical skill or risk. Among these are larger drilling clusters to cut down on rig move costs, flowlining instead of trucking condensate, building frac water source and produced water disposal systems near to our operations, commingling the shallower Cretaceous plays with the vertical portion of our Montney wellbores, large volume purchasing and then warehousing frac sand, well cement and tubulars at a rail terminal near the operations and, in some cases, processing our products to make them eligible for higher price markets. Many opportunities such as these have been identified and have been given a priority in the queue for capital allocation, but our resources, such as capital and expertise, will be applied to the limitation of our management ability to the "Nest" well and facility construction first. With this strategy, we hope to get to cash flow self-sufficiency with the least requirement for outside funding.

Of course, the largest upside relative to our existing proven plus probable reserve value is most likely in zones and regions that remain unestablished, unrecognized by the independent evaluator as meeting the reserve classification criteria. Part of that recognition can only be remedied with larger contracted transportation and processing because the reserve definition requires an expectation of market access within a defined period of time. To get zones and regions that are not seen to be economically productive to be recognized at least as Best Estimate Contingent resources though, we will have to drill them, tie them in and test their productivity. We can expect our first attempts at well construction in any region and/or zone to be sub-optimal and if the economics are close to toe of the boot we will probably want multiple demonstration and delineation wells to add credence to the value proposition.

So, taking a stab at value potential, do any of the zones have significant potential value relative to the reserve value of the upper and middle Montney in the Nest?

- I would say the lower Montney across our land base looks very encouraging. It is generally as thick on our lands as both the upper and middle Montney combined. It probably has slightly less porosity and slightly higher pressure so the recovery potential is of the same order of magnitude as the upper and middle Montney in the same area.
- The upper and middle Montney in the regions that we call Deep Sour and Wapiti are the main value drivers for some of our competitors.
  - I would say that the Wapiti region has been significantly drilled and tested to give us a reasonably high confidence in our type curves but, as with all areas, there are still benefits from optimal technology application to be gained.
  - The Deep Sour region really intrigues me because its high pressure may result in much higher well rates and higher recoveries per well once the region has been optimized. Further, even though the liquids content of the gas is

generally lower than it is in the "Nest" we would expect the liquid to remain in the gas phase during depletion and thus I think it is reasonable to estimate higher recovery factors for the liquids than we might see in the "Nest."

- None of the other zones are likely to have the same magnitude of recoverable resource as the full Montney section across our land base. In aggregate though, given the potential to commingle the more conventional zones with the Montney development and given the lower cost to develop the shallower resource play zones, we can feel optimistic about the potential for the rest of the column to add significant value.

In summary, I feel that the IPO was very successful because the stock buyers understood the robust economics, even in a down cycle, the nimbleness and diligence with which the Company has been managed and the strategic positioning the Company considers with its capital deployment. Every buyer likely had its own set of reasons to order and whatever they are, we are grateful and dedicated to abundantly rewarding the insightful support.

(Signed) *"Pat Carlson"*

Pat Carlson, P.Eng.
CEO

OPERATIONS UPDATE

During the third quarter of 2014, production averaged a record 35,820 boe/d, an increase of 406% from the third quarter of 2013 and a 49% increase over the second quarter of 2014. September 2014 averaged a production rate of 39,690 boe/d (59% liquids). As a result of significant increases in production volumes, revenue increased to $165 million, a 599% improvement versus the same period last year, and 35% over the second quarter of 2014.

7G achieved operating netbacks of $35.79 per boe in the third quarter of 2014, a 56% increase over the third quarter of 2013 and a 10% decrease relative to the second quarter of 2014 due to a weaker commodity price environment in the third quarter of 2014.

Net capital investments for the quarter totaled $328.4 million with approximately 72% invested on drilling and completions and 28% on facilities and well equipment. The Company increased its active drilling rig count to ten rigs, up from seven rigs at the beginning of the year, and rig-released ten wells with an average horizontal lateral length of approximately 2,838 meters. 7G also completed ten wells with an average of 32.8 stages and 3,796 tonnes of proppant per well.

Construction of the Karr 7-11 to Lator condensate pipeline and the Lator to Pembina pipeline was mechanically complete in third quarter of 2014. Commissioning and start-up is expected in the fourth quarter. Field construction of the 25,000 bbl/d stabilizer project at the Karr 7-11 battery commenced during the third quarter. The project is estimated to be mechanically complete in the fourth quarter of 2014 with commissioning anticipated in early 2015.

OUTLOOK

Given the Company's year-to-date production performance, 2014 average production is expected to meet previous estimates of 27,000 – 30,000 boe/d.

Previously announced 2014 capital investments were estimated to total $1.038 billion. Presently, 2014 capital is expected to be $1.067 billion. The difference is primarily due to higher than expected costs for well completions partly as a result of drilling longer than expected laterals and logistical challenges associated with the supply of nitrogen and other resources required for fracture treatments. The dedicated frac spread and systematic improvements in our stimulation technique is expected to improve the Company's capital efficiency going forward.

In the third quarter of 2014, the Board of Directors approved a 2015 capital budget of $1.6 billion which is designed to generate average annual production in 2015 of 55,000 to 60,000 boe/d. Included in this budget, 7G plans on increasing active rig count to 15 drilling rigs during the first half of 2015. Procurement and engineering for the Lator 2 gas plant expansion continued throughout the third quarter. Construction kickoff is planned for the first quarter of 2015, subject to regulatory approvals, and start-up is expected by the fourth quarter of 2015. The Lator 2 gas plant expansion will increase the Company's natural gas processing capacity to 250 MMcf/d by December 2015, consistent with its marketing commitments. The 2015 capital budget includes discretionary capital for delineation drilling and facility project pre-investment, equating to approximately 15% of the total capital budget. In the event that commodity prices remain low into 2015, the discretionary projects could be deferred to preserve the Company's strong balance sheet.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A"), dated November 12, 2014, is management's assessment of the historical financial position and results of Seven Generations Energy Ltd. (the "Company" or "Seven Generations") and should be read in conjunction with the unaudited condensed interim financial statements (the "financial statements") as at and for the three and nine months ended September 30, 2014 and the MD&A and audited financial statements as at and for the year ended December 31, 2013.

The financial information contained herein has been prepared in accordance with International Financial Reporting Standards ("IFRS"). All dollar amounts are expressed in Canadian currency, unless otherwise noted.

Certain financial measures referred to in this MD&A are not prescribed by IFRS. See "Non-IFRS Financial Measures" for information regarding the following non-IFRS financial measures used in this MD&A: "funds from operations", "operating netback" and "adjusted working capital". These non-IFRS measures and other financial estimates of management are based upon variable components. There can be no assurance that these components and future calculations of non-IFRS measures will not vary.

Additional information about Seven Generations is available on SEDAR at www.sedar.com.

Forward-Looking Information

This MD&A contains certain forward-looking information and statements within the meaning of applicable securities laws. 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 MD&A contains forward-looking information and statements pertaining to the following: the Company's financial goals under the heading "Description of Business", the information relating to the 2014 capital program under the heading "Capital Investments," the Company's estimates of normal course obligations under the heading "Contractual Obligations," and a number of other matters, including the amount of future asset retirement obligations, future liquidity and financial capacity, future results from operations and operating metrics, future costs, expenses and royalty rates, future interest costs, and future development, exploration, acquisition and development activities (including drilling plans) and related capital investments.

The forward-looking information and statements contained in this MD&A reflect several material factors and expectations and assumptions of the Company including, without limitation: that the Company will continue to conduct its operations in a manner consistent with past operations; the general continuance of current industry conditions; the continuance of existing (and in certain circumstances, the implementation of proposed) tax, royalty and regulatory regimes; the accuracy of the estimates of the Company's reserves and resource volumes; certain commodity price and other cost assumptions; and the continued availability of adequate debt and equity financing and cash flow to fund its planned expenditures. The Company believes the material factors, expectations and assumptions reflected in the forward-looking information and statements are reasonable, but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information and statements included in this MD&A are not guarantees of future performance and should not be unduly relied upon. Such information and statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information or statements including, without limitation: changes in commodity prices; changes in the demand for or supply of the Company's products; unanticipated operating results or production declines; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in development plans of the Company or by third party operators of the Company's properties, increased debt levels or debt service requirements; inaccurate estimation of the Company's oil and gas reserve and resource volumes; limited, unfavorable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; and certain other risks detailed from time to time in the Company's disclosure documents.

The forward-looking information and statements contained in this MD&A speak only as of the date of this MD&A, 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.

Boe Presentation

Barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. Condensate and other NGLs are converted to oil equivalent at a ratio of one to one barrels of oil. All boe conversions in this report are derived by converting natural gas to oil at the ratio of six thousand cubic feet of natural gas to one barrel of oil. A boe conversion rate of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

NON-IFRS 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", "adjusted working capital" and "operating netback". 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 and unaudited 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 flow from operating activities, the most directly comparable financial measure presented in accordance with IFRS, adjusted for changes in non-cash operating working capital and decommissioning expenditures. The Company has presented funds from operations because it uses funds from operations as an integral part of its internal reporting to measure its performance. Funds from operations 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 activities and eliminates the effect of changes in non-cash working capital, which is included in cash flow from 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 September 30		**Nine months ended September 30**	
	2014	2013	**2014**	2013
($ thousands)				
Cash flow from operating activities	**118,070**	14,666	**221,242**	41,131
Decommissioning expenditures	**-**	-	**206**	-
Changes in non-cash operating working capital	**(11,776)**	(9,886)	**4,982**	(13,972)
Funds from operations	**106,294**	4,780	**226,430**	27,159

Adjusted Working Capital
Adjusted working capital is comprised of current assets less current liabilities and excludes (current) risk management contracts and deferred credits. A summary of the reconciliation of adjusted working capital is set forth below:

	September 30, 2014	September 30, 2013
($ thousands)		
Current assets	**286,738**	239,699
Current liabilities	**(204,634)**	(110,781)
Working capital	**82,104**	128,918
Adjusted for:		
Risk management contracts	**(14,527)**	668
Current portion of deferred credits	**123**	-
Adjusted working capital	**67,700**	129,586

Operating Netback
"Operating Netback" is calculated on a per boe basis and is determined by deducting royalties, operating and transportation expenses from petroleum and natural gas revenue and, except where otherwise indicated, after adjusting for hedging gains or losses and processing and third party income. Operating netback is utilized by the Company to better analyze the operating performance of its petroleum and natural gas assets against prior periods.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

	Three months ended September 30			Nine months ended September 30		
	2014	2013 (5)	**% Change**	**2014**	2013 (5)	**% Change**
FINANCIAL ($000's except per share amounts)						
Oil and natural gas revenue	**165,501**	23,692	599	**391,828**	68,681	471
Funds from operations (1)	**106,294**	4,780	2,124	**226,430**	27,159	734
Per share – basic (2)	**0.55**	0.03	1,733	**1.19**	0.17	600
Per share – diluted (2)	**0.48**	0.03	1,500	**1.02**	0.16	538
Net income (loss)	**30,482**	(955)	3,292	**75,572**	(8,533)	986
Per share – basic (2)	**0.16**	(0.01)	1,700	**0.40**	(0.05)	900
Per share – diluted (2)	**0.14**	(0.01)	1,500	**0.34**	(0.05)	780
Total assets	**2,019,134**	1,134,257	78	**2,019,134**	1,134,257	78
Capital investments, net of dispositions	**328,423**	142,185	131	**740,596**	396,090	87
Adjusted working capital (1)	**67,700**	129,586	(48)	**67,702**	129,586	(48)
Senior notes (3)	**784,000**	412,120	90	**784,000**	412,120	90
Shares outstanding, end of period (#000s)						
Class A Common Voting Shares (2)	**192,271**	165,340	16	**192,271**	165,340	16
Class B Common Non-Voting Shares	**816**	966	(16)	**816**	966	(16)
Weighted average shares (#000s) – basic (2)	**192,460**	167,272	15	**189,560**	166,950	14
OPERATING						
Production						
Oil and natural gas liquids (bbls/d)	**20,869**	3,253	542	**15,527**	3,250	378
Natural gas (Mmcf/d)	**89.7**	23.0	290	**67.3**	19.5	245
Oil equivalent (boe/d)	**35,820**	7,084	406	**26,739**	6,505	311
Realized prices						
Oil and natural gas liquids ($/bbl)	**66.33**	60.52	10	**70.16**	57.09	23
Natural gas ($/mcf)	**4.62**	2.64	75	**5.14**	3.38	52
Oil equivalent ($/boe)	**50.22**	36.35	38	**53.67**	38.67	39
Operating netback per boe ($)						
Oil and natural gas revenue	**50.22**	36.35	38	**53.67**	38.67	39
Realized hedging (loss) gain	**(0.04)**	0.03	(233)	**(1.70)**	0.13	(1,408)
Processing and third party income	**0.17**	0.77	(78)	**0.15**	0.71	(79)
Royalties	**(6.35)**	(3.42)	86	**(4.90)**	(2.63)	86
Operating expenses (4)	**(4.32)**	(6.91)	(38)	**(4.83)**	(6.86)	(30)
Transportation expenses (4)	**(3.89)**	(3.82)	2	**(4.65)**	(4.03)	15
Operating netback (1)	**35.79**	23.00	56	**37.74**	25.99	45
Undeveloped land holdings						
Gross acres	**290,236**	223,196	30	**290,236**	223,196	30
Net acres	**284,442**	219,245	30	**284,442**	219,245	30
Number of wells drilled – gross (net)	**10 (10.0)**	8 (8.0)	25	**35 (35.0)**	12 (12.0)	192

(1) See "Non-IFRS Financial Measures"
(2) On September 8, 2014, the Company amended its articles of incorporation to divide the issued and outstanding Class A Common Voting Shares on a two-for-one basis. The share split has been reflected in the condensed interim statements for the three and nine months ended September 30, 2014 and on a retroactive basis.
(3) Senior notes as reported represent US$700.0 million principal converted to Canadian dollars at the closing exchange rate for the period end.
(4) Certain comparative figures for prior periods have been reclassified to conform to the current period's presentation.

SUBSEQUENT EVENT

On October 29, 2014, the Company signed an underwriting agreement and filed a final prospectus for an initial public offering ("IPO") to raise gross proceeds of $810 million through the issuance of 45 million Class A Common Voting Shares at a price of $18.00 per common share (the "IPO price"). The underwriters' commission was 5% of the gross proceeds of the IPO. The expenses of the IPO, excluding the underwriters' commission, are estimated to be approximately $2.5 million, and will be paid by the Company out of the proceeds of the treasury offering. The IPO closed on November 5, 2014. As part of the IPO, the underwriters exercised an option (the "Over- Allotment Option") for an additional 6.75 million Class A Common Voting Shares (representing 15% of the base IPO), resulting in gross proceeds of $121.5 million.

The Company's Class A Common Voting Shares trade under the symbol "VII" on the Toronto Stock Exchange.

DESCRIPTION OF BUSINESS

Seven Generations is a Canadian company engaged in the development of the Kakwa River Project (the "Project"). Located approximately 100 kilometers south of Grande Prairie, Alberta, the Project is a tight, liquids rich gas and light oil project in the early stages of development. Seven Generations has a corporate headquarters in Calgary, Alberta and an operations headquarters in Grande Prairie, Alberta.

RESULTS OF OPERATIONS

Daily Production

	Three months ended September 30			**Nine months ended September 30**		
	2014	2013	**% Change**	**2014**	2013	**% Change**
Oil and natural gas liquids (bbls/d)	**20,869**	3,253	542	**15,527**	3,250	378
Natural gas (Mmcf/d)	**89.7**	23.0	290	**67.3**	19.5	245
Total (boe/d)	**35,820**	7,084	406	**26,739**	6,505	311

The Company's production for the third quarter of 2014 averaged 35,820 boe/d, which represents a 406% increase over 7,084 boe/d in the third quarter of 2013 and a 49% increase from the second quarter of 2014 which averaged 23,999 boe/d. For the first nine months of 2014, the Company's production increased to 26,739 boe/d compared to 6,505 boe/d for the same period in 2013, an increase of 311%.

Oil and natural gas liquids volumes in the third quarter of 2014 includes 12,580 bbls/d of oil and condensate and 8,289 bbls/d of natural gas liquids such as propane, butane, pentane and ethane. These represent significant increases over third quarter of 2013 volumes of 1,614 bbls/d of oil and condensate and 1,639 bbls/d of natural gas liquids.

For both the three and nine months ended September 30, 2014, oil and natural gas liquids accounted for 58% of total production volume compared to 46% and 50%, respectively, of total production in the comparative periods of 2013.

Commodity Pricing

	Three months ended September 30			**Nine months ended September 30**		
	2014	2013	**% Change**	**2014**	2013	**% Change**
Average Benchmark Prices						
Oil – WTI (US$/bbl)	**97.26**	105.83	(8)	**99.63**	98.16	2
Oil – Edmonton Par ($/bbl)	**97.33**	105.17	(8)	**101.37**	95.57	6
Natural gas – AECO NGX 5A ($/mcf)	**4.02**	2.44	65	**4.78**	3.00	59
Average exchange rate – (CAD to US)	**0.918**	0.963	(5)	**0.914**	0.977	(6)

The Company realized the following commodity prices:

	Three months ended September 30			**Nine months ended September 30**		
	2014	2013	**% Change**	**2014**	2013	**% Change**
Oil and natural gas liquids ($/bbl)	**66.33**	60.52	10	**70.16**	57.09	23
Natural gas ($/mcf)	**4.62**	2.64	75	**5.14**	3.38	52
Total ($/boe)	**50.22**	36.35	38	**53.67**	38.67	39

Average AECO natural gas prices for the third quarter increased 65% in 2014 compared to 2013. As a result, the Company's average realized natural gas price has increased by 75% to $4.62/mcf for the third quarter of 2014 compared to $2.64/mcf in the same period in 2013. The Company receives a blend of pricing based on AECO 7A and 5A benchmark indexes. The relative pricing between these two indexes has fluctuated throughout the quarter. The Company's average realized natural gas price is higher than AECO natural gas prices due to a premium received for heating content.

The average realized prices for oil and natural gas liquids primarily reflect a combination of prices for condensate and for natural gas liquids such as propane, butane, pentane and ethane. The Company's average realized prices have increased for both product streams in the third quarter of 2014 by 10% to $66.33/bbl compared to $60.52/bbl for the same period in 2013. For the first nine months of 2014, the Company realized average prices of $70.16/bbl for natural gas liquids as compared to $57.09/bbl for the comparative period in 2013, an increase of 23%.

Revenues

	Three months ended September 30			Nine months ended September 30		
	2014	2013	**% Change**	**2014**	2013	**% Change**
($ thousands)						
Oil and natural gas liquids	**127,343**	18,110	603	**297,423**	50,672	487
Natural gas	**38,158**	5,582	584	**94,405**	18,009	424
Revenues (excluding realized gains or losses on risk management contracts)	**165,501**	23,692	599	**391,828**	68,681	471

Revenues increased by $141.8 million or 599% to $165.5 million in the third quarter of 2014 compared to $23.7 million in the same period of 2013. The increase in revenues is due to higher production volumes combined with higher commodity prices. For the nine months ended September 30, 2014, the increase in revenues was $323.1 million, an increase of 471%, to $391.8 million compared to $68.7 million for the same period in 2013.

Risk Management Contracts

The Company utilizes financial commodity price hedges to protect funds from operations against commodity price volatility. The Company's risk management program resulted in the following:

	Three months ended September 30			Nine months ended September 30		
	2014	2013	**% Change**	**2014**	2013	**% Change**
($ thousands)						
Realized gain (loss)	**(148)**	17	(971)	**(12,426)**	230	(5,503)
Unrealized gain (loss)	**33,390**	(765)	4,465	**17,993**	(1,321)	1,462
Total gain (loss)	**33,242**	(748)	4,544	**5,567**	(1,091)	610

The fair value of unsettled financial instruments is recorded as an asset or liability with the change in value recorded as an unrealized gain or loss in the statements of net income and cash flows.

The following hedging contracts were outstanding at September 30, 2014:

Commodity	Term	Contract	Volume	Average Price/Unit
Natural gas	Oct 1, 2014 - Dec 31, 2014	Fixed Price	41,000 GJ/d	CDN$3.91
Natural gas	Oct 1, 2014 - Dec 31, 2014	Costless Collar	24,000 GJ/d	CDN$4.00 - $5.00
Natural gas	Jan 1, 2015 - Dec 31, 2015	Fixed Price	8,500 GJ/d	CDN$3.82
Natural gas	Jan 1, 2015 - Mar 31, 2015	Fixed Price	7,000 GJ/d	CDN$4.20
Natural gas	Jan 1, 2015 - Mar 31, 2015	Costless Collar	58,000 GJ/d	CDN$4.07 - $5.24
Natural gas	Apr 1, 2015 - Jun 30, 2015	Fixed Price	25,000 GJ/d	CDN$3.86
Natural gas	Apr 1, 2015 - Dec 31, 2015	Fixed Price	30,000 GJ/d	CDN$3.91
Natural gas	Jul 1, 2015 - Sept 30, 2015	Fixed Price	5,000 GJ/d	CDN$3.86
Natural gas	Oct 1, 2015 - Dec 31, 2015	Fixed Price	10,000 GJ/d	CDN$3.78
Oil	Oct 1, 2014 - Dec 31, 2014	Fixed Price	7,400 bbls/d	CDN$104.86
Oil	Oct 1, 2014 - Dec 31, 2014	Costless Collar	3,400 bbls/d	CDN$100.00-$110.98
Oil	Jan 1, 2015 - Dec 31, 2015	Fixed Price	1,100 bbls/d	CDN$99.81
Oil	Jan 1, 2015 - Mar 31, 2015	Fixed Price	10,100 bbls/d	CDN$102.57
Oil	Apr 1, 2015 – Jun 30, 2015	Fixed Price	10,500 bbls/d	CDN$102.43
Oil	Jul 1, 2015 – Sept 30, 2015	Fixed Price	6,500 bbls/d	CDN$101.44
Oil	Oct 1, 2015 - Dec 31, 2015	Fixed Price	1,000 bbls/d	CDN$100.75

At September 30, 2014, the net fair value of these contracts was an asset of $15.3 million (December 31, 2013 – liability of $2.6 million). Realized gains and losses on these contracts are recognized on the monthly settlement of the contracts.

Subsequent to September 30, 2014, the Company entered into new hedging contracts as follows:

Commodity	Term	Contract	Volume	Average Price/Unit
Natural gas	Jul 1, 2015 – Dec 31, 2015	Fixed Price	20,000 GJ/d	CDN$3.46
Natural gas	Oct 1, 2015 - Dec 31, 2015	Fixed Price	5,000 GJ/d	CDN$3.75
Natural gas	Jan 1, 2016 – Mar 31, 2016	Fixed Price	17,500 GJ/d	CDN$3.79
Oil	Apr 1, 2015 – Jun 30, 2015	Fixed Price	500 bbls/d	CDN$96.33

Royalty Expense

	Three months ended September 30			Nine months ended September 30		
	2014	2013	**% Change**	**2014**	2013	**% Change**
($ thousands, except per unit amounts)						
Gross royalties	**21,814**	2,596	740	**38,294**	6,723	470
Gas cost allowance (“GCA”)	**(889)**	(369)	141	**(2,549)**	(2,058)	24
Net royalties	**20,925**	2,227	840	**35,745**	4,665	666
Per boe	**6.35**	3.42	86	**4.90**	2.63	86
Effective royalty rate						
Gross	**13%**	11%	18	**10%**	10%	-
Net	**13%**	9%	44	**9%**	7%	29

The average gross royalty rate for the third quarter of 2014 were 13% compared to 11% in the same period of 2013. The new Montney wells on production qualify for various royalty incentives for a period of time. The percentage of the Company’s total production eligible for incentives at any one time will vary depending on the timing that new wells are brought on production and the volumes produced by those wells. The increase in the overall average royalty rate for the third quarter of 2014 is due to royalty incentives ending for certain wells. For the fourth quarter of 2014, the Company expects the effective royalty rate (net) to be approximately 10% due to new wells commencing production that will qualify for royalty incentives.

For the three months ended September 30, 2014, GCA increased by $0.5 million, or 141%, compared to the same period in 2013. GCA deductions are estimated during a production year, and are subject to adjustment in the second quarter of the following year after actual cost filings have been processed by the Alberta Crown. GCA deductions are largely based on amortization of historical costs, and therefore do not necessarily remain constant on a per unit or percentage of revenue basis.

Interest and Third Party Income

	Three months ended September 30			Nine months ended September 30		
	2014	2013	**% Change**	**2014**	2013	**% Change**
($ thousands, except per unit amounts)						
Interest and other income	**512**	506	1	**1,920**	1,013	90
Processing and third party income	**571**	501	14	**1,099**	1,255	(12)
Total	**1,083**	1,007	8	**3,019**	2,268	33
Per boe – interest & other income	**0.16**	0.77	(79)	**0.26**	0.57	(54)
Per boe – processing & third party income	**0.17**	0.77	(78)	**0.15**	0.71	(79)

The average cash balances held by the Company for the first nine months of 2014 were higher than in the same period of 2013 which increased interest and other income by $0.9 million to $1.9 million. The Company received net proceeds of $346.5 million from a debt financing in February 2014. In 2013, two financings were completed. In May 2013, the Company raised debt for net proceeds of $393.8 million, and in December 2013, the Company received $238.3 million of net proceeds from an equity issue.

Processing income and third party income increased to $0.6 million in the third quarter of 2014 from $0.5 million in the third quarter of 2013; this increase was mainly due to higher volumes from third party wells in the third quarter of 2014. For the first nine months of 2014, processing income decreased by $0.2 million or, 12%, to $1.1 million from $1.3 million in the same period of 2013. With increased production from the Company’s own wells, the volume of third party volumes processed through Company-owned facilities is expected to decrease.

Operating Expenses

	Three months ended September 30			Nine months ended September 30		
	2014	2013	**% Change**	**2014**	2013	**% Change**
($ thousands, except per unit amounts)						
Operating expenses	**14,245**	4,502	216	**35,295**	12,190	190
Per boe	**4.32**	6.91	(38)	**4.83**	6.86	(30)

Total operating expenses increased as a result of higher liquids production and field activity levels, including increased field staffing to accommodate super pad operations. On a unit of production basis, operating expenses for the third quarter of 2014 decreased by $2.59/boe or 38% to $4.32/boe as compared to $6.91/boe in the third quarter of 2013. Operating expenses per boe have improved in the first nine months of 2014 with a number of new wells coming on production. As such, the unit of production operating expenses for the nine months of 2014 decreased by $2.03/boe or 30% to $4.83/boe as compared to $6.86/boe for the same period in 2013.

The Company's 2014 capital budget includes construction of four super pad facilities, which are sites that contain gas compression, separation, dehydration and liquids pumping capabilities, and installation of a 25,000 bbls/d condensate stabilizer. The super pad facilities were online in the third quarter 2014 while construction of the stabilizer commenced and is expected to be operational by the first quarter of 2015.

Transportation Expenses

	Three months ended September 30			Nine months ended September 30		
	2014	2013	**% Change**	**2014**	2013	**% Change**
($ thousands, except per unit amounts)						
Transportation expenses	**12,814**	2,486	415	**33,974**	7,156	375
Per boe	**3.89**	3.82	2	**4.65**	4.03	15

Transportation expenses include condensate and NGL pipeline tariffs and trucking as well as gas pipeline tariffs. Transportation expenses increased on a per unit of production basis by $0.07/boe to $3.89/boe in the third quarter of 2014 compared to $3.82/boe for the same period in 2013. The increase is primarily due to higher trucking costs as condensate was trucked to feeder pipeline terminals and truck facilities rather than the pipeline terminal as a result of pipeline capacity restrictions in the Grande Prairie area. For the nine months ended September 30, 2014, on a unit of production basis, transportation expenses increased $0.62/boe or 15% to $4.65/boe from $4.03/boe for the comparative period in 2013.

General and Administrative Expenses

	Three months ended September 30			Nine months ended September 30		
	2014	2013	**% Change**	**2014**	2013	**% Change**
($ thousands, except per unit amounts)						
Gross general and administrative expenses	**5,328**	2,683	99	**15,657**	8,126	93
Capitalized overhead costs	**(650)**	(516)	26	**(2,138)**	(1,600)	34
Overhead recoveries	**(221)**	(161)	37	**(654)**	(461)	42
Net general and administrative expenses	**4,457**	2,006	122	**12,865**	6,065	112
Per boe – gross	**1.62**	4.12	(61)	**2.14**	4.58	(53)
Per boe – net	**1.35**	3.08	(56)	**1.76**	3.42	(49)

Gross general and administrative expenses for the third quarter of 2014 increased by $2.6 million to $5.3 million from $2.7 million for the comparative period in 2013. For the first nine months of 2014, gross general administrative expenses are higher by $7.6 million or 93%, compared to the same period in 2013. This increase is primarily attributable to increased personnel costs to support the Company's expanded activities. However, as a result of higher production levels, gross general and administration expenses on a unit of production basis decreased by $2.50/boe or 61% to $1.62/boe for the three months ended September 30, 2014 compared to $4.12/boe in the same period of 2013.

Depletion, Depreciation and Amortization

	Three months ended September 30			Nine months ended September 30		
	2014	2013	**% Change**	**2014**	2013	**% Change**
($ thousands, except per unit amounts)						
Total depletion, depreciation & amortization	**46,927**	8,104	479	**101,477**	25,213	302
Per boe	**14.24**	12.43	15	**13.90**	14.20	(2)

Depletion, depreciation and amortization expense was $46.9 million and $101.5 million for the three and nine months ended September 30, 2014, compared to $8.1 million and $25.2 million in the comparative periods of 2013, respectively. This is a result of a 406% increase in production volumes for the third quarter compared to the same period of 2013. On a boe basis, there was an increase of $1.81/boe or 15%, to $14.24/boe for the third quarter of 2014 compared to $12.43/boe in the same period of 2013 and a decrease of $0.30/boe or 2% in the first nine months of 2014 to $13.90/boe from $14.20/boe for same period in 2013.

Stock Based Compensation

	Three months ended September 30			Nine months ended September 30		
	2014	2013	**% Change**	**2014**	2013	**% Change**
($ thousands)						
Gross stock based compensation	**5,193**	5,018	4	**11,952**	11,195	7
Capitalized stock based compensation	**(1,649)**	(1,351)	22	**(3,899)**	(3,191)	22
Net stock based compensation	**3,544**	3,667	(3)	**8,053**	8,004	1

Stock based compensation is a non-cash expense. Gross stock based compensation for the third quarter of 2014 has increased by $0.2 million to $5.2 million compared to $5.0 million for the same period of 2013. In the third quarter of 2013, the stock options and performance warrants granted in 2008 were amended to extend the expiry date by one year. As a result of these amendments, a one-time charge of $2.1 million (net - $1.7 million) of expense was recognized in the third quarter of 2013. For the first nine months of 2014, there was an increase of $0.8 million or 7% to $12.0 million in gross stock based compensation as compared to $11.2 million in the same period of 2013.

The stock based compensation values are estimated using the Black-Sholes pricing model in which estimates for expected life of the instruments, current market value of the shares compared to exercise price, stock volatility and interest rates are all important variables. 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.

Gain (Loss) on Disposition of Assets

	Three months ended September 30			Nine months ended September 30		
	2014	2013	**% Change**	**2014**	2013	**% Change**
($ thousands						
Gain (loss) on disposition of assets	**(281)**	-	100	**3,239**	-	100

During the nine months ended September 30, 2014, 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 three months ended September 30, 2014, losses were recorded related to expired mineral leases. The Company recorded a gain of $3.2 million on the assets disposed of for the nine months ended September 30, 2014.

Finance Expense

	Three months ended September 30			Nine months ended September 30		
	2014	2013	**% Change**	**2014**	2013	**% Change**
($ thousands)						
Interest on senior notes	**15,724**	8,568	84	**44,760**	13,378	235
Revolving credit facility fees and other	**313**	123	154	**1,285**	558	130
Amortization of premium and debt issue costs	**12**	295	(96)	**(352)**	448	(179)
Accretion	**289**	207	40	**890**	499	78
	16,338	9,193	78	**46,583**	14,883	213

On May 10, 2013, the Company issued US$400.0 million of senior unsecured notes. On February 5, 2014 an additional US$300.0 million (US$321.0 million with premium) of senior unsecured notes were issued under the same indenture. The notes bear interest at 8.25% per annum (calculated using a 360-day year). Interest expense for the third quarter of 2014 was $15.7 million (US$14.4 million), which is recorded in Canadian dollars using average monthly exchange rates.

The standby fees and other charges associated with the Company's revolving credit facility increased to $0.3 million and $1.3 million in the three and nine months ended September 30, 2014 compared to $0.1 million and $0.6 million in the same periods of 2013, respectively. This is due to higher standby fees as a result of the increases to the borrowing capacity on the credit facility in 2014.

Accretion expense relates to decommissioning liabilities which are recorded over time at their present value. Accretion expense increased by $0.1 million in the third quarter of 2014 to $0.3 million due to new wells drilled and new facilities. For the first nine months of 2014, accretion was $0.9 million compared to $0.5 million for the comparative period in 2013. Accretion and amortization of premium and debt issue costs are non-cash expenses.

Foreign Exchange Loss (Gain)

	Three months ended September 30			Nine months ended September 30		
	2014	2013	**% Change**	**2014**	2013	**% Change**
($ thousands)						
Unrealized	**38,059**	(8,768)	2,233	**25,844**	7,097	264
Realized	**(5,000)**	1,631	(43)	**(3,731)**	(6,940)	(46)
Net foreign exchange loss (gain)	**33,059**	(7,137)	563	**22,113**	157	13,985
As at September 30:						
C$ equivalent of 1 US$	**0.893**	0.971	(8)	**0.893**	0.971	(8)

The Company's exposure to foreign exchange gains and losses relates to the US dollar senior unsecured notes, as well as US dollar cash balances. The unrealized foreign exchange loss of $25.8 million for the nine months ended September 30, 2014 is primarily due to the change in foreign exchange rates since February 2014, when the US$300.0 million senior unsecured notes were issued. Unrealized foreign exchange losses for the third quarter of 2013 were $38.1 million compared to $1.6 million for the comparative period in 2013. The Company has also realized foreign exchange gains of $3.7 million on US dollar cash balances. The Company converted US$275.0 million to Canadian dollars in the first nine months of 2014. Realized foreign exchange gains on the conversion and remaining cash balances still held in US dollars and the settlement of normal revenues and invoices denominated in US dollars was $5.0 million for the third quarter of 2014.

Deferred Income Tax Expense (Recovery)

	Three months ended September 30			Nine months ended September 30		
	2014	2013	**% Change**	**2014**	2013	**% Change**
($ thousands)						
Deferred income tax expense (recovery)	**16,754**	(142)	11,899	**31,976**	58	55,031

For the nine months ended September 30, 2014, deferred income tax expense increased to $32.0 million from $0.1 million in the same period of 2013. The Company recognized a deferred income tax expense of $16.7 million for the three months ended September 30, 2014, an increase of $16.8 million from a $0.1 million deferred income tax recovery recorded for the three months ended September 30, 2013. The Company's effective income tax rate is impacted by permanent differences. Stock based compensation is a non-deductible expense and foreign exchange gains or losses relating to the issue of the senior notes are one-half taxable or deductible. The majority of the permanent differences for the three and nine months ended September 30, 2014 relate to $3.6 million and $8.1 million, respectively, for non-taxable stock based compensation expense and $16.0 million and $12.2 million, respectively, for non-taxable portion of foreign exchange losses arising on the translation of the US dollar denominated senior notes and cash.

Funds from Operations and Net Income (Loss)

	Three months ended September 30			Nine months ended September 30		
	2014	2013	**% Change**	**2014**	2013	**% Change**
($ thousands, except per share amounts)						
Funds from operations	**106,294**	4,780	2,124	**226,430**	27,159	734
Per share – basic (1)	**0.55**	0.03	1,733	**1.19**	0.17	600
Per share – diluted (1)	**0.48**	0.03	1,500	**1.02**	0.16	538
Net income (loss)	**30,482**	(955)	3,292	**75,572**	(8,533)	986
Per share – basic (1)	**0.16**	(0.01)	1,700	**0.40**	(0.05)	900
Per share – diluted (1)	**0.14**	(0.01)	1,500	**0.34**	(0.05)	780

(1) On September 8, 2014, the Company amended its articles of incorporation to divide the issued and outstanding Class A Common Voting Shares on a two-for-one basis. The share split has been reflected in the condensed interim statements for the three and nine months ended September 30, 2014 and 2013 on a retroactive basis.

Funds from operations increased by $101.5 million in the third quarter of 2014 to $106.3 million compared to $4.8 million in the same period of 2013. The increase was due to production volumes increasing by 406% combined with higher netbacks due to improved commodity pricing that was partially offset by interest expense on the senior notes. For the first nine months of 2014, funds from operations increased by $199.2 million to $226.4 million compared to $27.2 million in the same period of 2013, an increase of $1.02 per share ($0.86 per share, diluted).

Net income increased by $31.5 million to $30.5 million for the third quarter of 2014 compared to a net loss of $1.0 million in the comparative 2013 period. The increase in net income was attributable to the items impacting funds from operations noted above as well as unrealized gains on risk management contracts of $33.4 million. This was offset by higher depletion charges as production volumes have increased, $38.1 million of unrealized foreign exchange losses and $16.8 million for deferred income tax expense. The increase to net income for the first nine months of 2014 was $84.1 million to $75.6 million, an increase of $0.45 per share ($0.39 per share, diluted) as compared to a net loss of $8.5 million for the same period in 2013.

Capital Investments

	Three months ended September 30			Nine months ended September 30		
	2014	2013	**% Change**	**2014**	2013	**% Change**
($ thousands)						
Land acquisitions	**1,408**	8,991	(84)	**40,484**	58,373	(31)
Geological and geophysical	**216**	3	71	**268**	5	5,260
Drilling and completions	**234,879**	102,314	130	**514,457**	192,579	167
Facilities and equipment	**90,447**	29,707	204	**190,425**	141,977	34
Capitalized salaries and benefits	**862**	587	47	**2,786**	1,650	69
Office and other	**611**	583	5	**1,596**	1,506	6
Total capital investment	**328,423**	142,185	131	**750,016**	396,090	89
Property dispositions	**-**	-	-	**(9,420)**	-	100
Capital investment, net of dispositions	**328,423**	142,185	131	**740,596**	396,090	87

Over the past year, Seven Generations has significantly accelerated its capital investment program. The Company exited the third quarter of 2014 with ten drilling rigs, compared to seven rigs operating in the third quarter of 2013. Drilling and completions has increased $132.6 million, investing $234.9 million in the third quarter of 2014 compared to the same period in 2013. Similarly, facilities and equipment investing increased $60.7 million to $90.5 million for the three months ended September 30, 2014 compared to $29.7 million in 2013. Land acquisitions was $1.4 million for the third quarter of 2014 compared to $9.0 million for the same period in 2013.

LIQUIDITY AND CAPITAL RESOURCES

The capital structure of the Company is as follows:

As at	**September 30, 2014**	December 31, 2013
Senior notes	**785,830**	414,525
Adjusted working capital deficiency[1]	**-**	-
Total debt	**785,830**	414,525
Total debt as a % of total capital	**45%**	33%
Total equity [2]	**941,100**	827,953
Total equity as a % of total capital	**55%**	67%
Total capital	**1,726,930**	1,242,478

(1) Adjusted working capital is defined as current assets less current liabilities, excluding unrealized financial instruments and deferred credits.
(2) Equity is defined as share capital plus contributed surplus plus any retained earnings (deficit) and other comprehensive income (deficit).

The Company's objective for managing capital continues to be to maintain a strong balance sheet and capital base to provide financial flexibility to position the Company for 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. Near-term major acquisitions and capital development will be funded by funds flow from operations, cash or cash equivalents, equity financings, the available credit facility and debt financings. 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. The Company monitors its financing requirements and will pursue further debt or equity financings to support capital development and acquisition objectives, as required.

On May 10, 2013, the Company closed a private placement of US$400.0 million of senior unsecured notes. On February 5, 2014, the Company closed a private placement of an additional US$300.0 million of senior unsecured notes issued under the same indenture. The notes issued in February 2014 were issued at 107% of par, resulting in gross proceeds to the Company of US$321.0 million. The notes bear interest at 8.25% per annum (calculated using a 360-day year) payable on May 15 and November 15 of each year. The notes will mature May 15, 2020.

In December 2013, the Company closed a private equity placement of approximately 20.0 million Class A Common Shares at $12.50 per share, for total gross proceeds of $251.0 million (net $238.3 million).

At September 30, 2014, the Company had adjusted working capital of $67.7 million (December 31, 2013 – $214.9 million). In the third quarter of 2014, the Company increased its revolving credit facility to $480.0 million, which has a three year term ending in September 2017. The credit facility is subject to a redetermination of the borrowing base semi-annually and is secured by a floating charge over the Company's assets. The credit facility bears interest rates based on a pricing grid that increases as a result of the increased ratio of indebtedness to earnings before interest, taxes, depreciation, depletion and amortization. The credit facility also includes standby fees on balances not drawn. The Company is not subject to externally imposed capital requirements.

In the fourth quarter of 2014, the Company closed its IPO for gross proceeds of $931.5 million, including the underwriters' Over-Allotment Option. The Company plans to fund the remaining capital budget for 2014 of approximately $326 million and the 2015 capital budget of $1.6 billion using the net IPO proceeds along with adjusted working capital, the available credit facility of $480.0 million and funds from operations. The Company anticipates continuing to accelerate and add drilling rigs throughout the remainder of 2014 with a significant portion of the 2014 fourth quarter capital budget allocated to drilling and completions. Facilities and equipment investments for the remainder of 2014 is directed towards expanding the Company's capacity to bring on additional production and to meet pipeline specifications. The Company's 2014 and 2015 capital budgets for facilities, includes construction of an additional 250 Mmcf/d natural gas plant, interconnecting pipeline and a meter station on the Alliance pipeline system. These facilities are expected to be on-stream in the second quarter of 2016 in advance of the Company's shipping capacity on the Alliance pipeline system which is anticipated to increase total raw gas production up to 500 Mmcf/d by 2018.

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 September 30, 2014:

	Total	Less than 1 year	1-3 years	4-5 years	Thereafter
($ thousands)					
Accounts payable and accrued liabilities	**198,170**	198,170	-	-	-
Senior notes [1]	**784,000**	-	-	-	784,000
Interest on senior notes [1]	**363,826**	64,681	129,360	129,360	40,425
Firm transportation and processing agreements [2]	**1,039,893**	7,554	267,142	283,391	481,806
Operating leases [3]	**14,769**	2,061	4,014	3,277	5,417
Estimated contractual obligations	**2,400,658**	272,466	400,516	416,028	1,311,648

(1) Balances denominated in US dollars have been translated at the September 30, 2014 exchange rate.
(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.

Effective August 27, 2014, the Company entered into an agreement to have a third party provide a 24-hour dedicated crew for hydraulic fracturing. The agreement has an initial term of one year. The Company may terminate the agreement on less than 60 days' notice and payment to the third party of an amount equal to $50,000 for each day less than 60 days that notice of the termination is given.

Subsequent to September 30, 2014, the Board of Directors approved a retention bonus plan for management and employees. The retention bonuses will be payable in four equal instalments payable every six months starting on May 5, 2015. Each instalment payment will be contingent upon the individual still being employed by the Company on the date of payment. The maximum retention bonuses payable over the two-year period starting November 5, 2014 is approximately $6.0 million.

OFF-BALANCE SHEET ARRANGEMENTS

The Company has certain fixed lease arrangements which were entered into in the normal course of operations. All leases are treated as operating leases, where the lease payments are included in operating expenses or G&A expenses depending on the nature of the lease. No asset or liability has been recorded for these leases on the balance sheet at September 30, 2014 or December 31, 2013. These arrangements are disclosed in the notes to the annual financial statements of the Company.

The Company did not have any physical delivery contracts outstanding at September 30, 2014 or December 31, 2013.

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 November 12, 2014, Seven Generations had 244,353,704 Class A Common Voting Shares and 649,657 Class B Common Non-Voting Shares issued and outstanding.

On September 8, 2014, the Company amended its articles of incorporation to divide the issued and outstanding Class A Common Voting Shares on a two-for-one basis. The Class B Common Non-Voting Shares were not divided. Stock options and performance warrants issued prior to the completion of the IPO will continue to be exercisable into the same number of Class B Common Non-Voting Shares. On conversion of Class B Common Non-Voting Shares into Class A Common Voting Shares, holders will receive two Class A Common Voting Shares for each Class B Common Non-Voting Share converted. The share split has been reflected in the condensed interim statements for the three and nine months ended September 30, 2014 on a retroactive basis for the Class A Common Voting Shares and per share information.

INTERNAL CONTROL OVER FINANCIAL REPORTING

The Company is required to comply with National Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings". The Company is not required to make any certifications regarding the disclosure controls and procedures ("DC&P") and internal control over financial reporting ("ICFR") in place as at September 30, 2014. Management will certify the design of the Company's DC&P and ICFR as at March 31, 2015 and the effectiveness of DC&P and ICFR as at December 31, 2015. The evaluation of ICFR will be based on the framework in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. 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.

CRITICAL ACCOUNTING ESTIMATES

A summary of the Company's significant accounting policies can be found in note 3 to the December 31, 2013 financial statements. The preparation of the financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets and liabilities, income and expenses. Actual results may differ from these estimates. There have been no significant changes in the Company's critical accounting estimates from those disclosed in management's discussion and analysis for the year ended December 31, 2013.

CHANGES IN ACCOUNTING POLICIES

As of January 1, 2014, the Company adopted several new IFRS interpretations and amendments in accordance with the transitional provisions of each standard. A brief description of each new accounting policy and its impact on the Company's financial statements is provided below.

IAS 36 "Impairment of Assets" has been amended to reduce the circumstances in which the recoverable amount of cash generating units is required to be disclosed and clarify the disclosures required when an impairment loss has been recovered or reversed in the period. The retrospective adoption of these amendments will only impact the Company's disclosures in the notes to the financial statements in periods when an impairment loss or impairment reversal is recognized.

IAS 39 "Financial Instruments: Recognition and Measurement" has been amended to clarify that there would be no requirement to discontinue hedge accounting if a hedging derivative was novated, provided certain criteria are met. The retrospective adoption of the amendments does not have any impact on the Company's financial statements.

IFRIC 21 “Levies” was developed by the IFRS Interpretations Committee and is applicable to all levies imposed by governments under legislation, other than outflows that are within the scope of other standards (e.g., IAS 12 “Income Taxes”) and fines or other penalties for breaches of legislation. The interpretation clarifies that an entity recognizes a liability for a levy when the activity that triggers payment, as identified by the relevant legislation, occurs. It also clarifies that a levy liability is accrued progressively only if the activity that triggers payment occurs over a period of time, in accordance with the relevant legislation. Lastly, the interpretation clarifies that a liability should not be recognized before the specified minimum threshold to trigger that levy is reached. The retrospective adoption of this standard does not have any material impact on the Company’s financial statements.

FUTURE ACCOUNTING POLICY CHANGES

In February 2014, the IASB tentatively decided to require an entity to apply IFRS 9 "Financial Instruments" for annual periods beginning on or after January 1, 2018. IFRS 9 is still available for early adoption. The full impact of the standard on the Company’s financial statements will not be known until changes are finalized.

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. The standard is required to be adopted either retrospectively or using a modified transition approach for fiscal years beginning on or after January 1, 2017, with earlier adoption permitted. IFRS 15 will be applied by Seven Generations on January 1, 2017 and the Company is currently evaluating the impact of the standard on the financial statements.

SELECTED QUARTERLY INFORMATION

	Q3 2014	Q2 2014	Q1 2014	YTD 2014
FINANCIAL ($ thousands, except per share amounts)				
Oil and natural gas liquids revenues	**127,343**	93,742	76,338	297,423
Natural gas revenues	**38,158**	29,254	26,993	94,405
Total revenues	**165,501**	122,996	103,331	391,828
Realized hedging loss	**(148)**	(6,873)	(5,405)	(12,426)
Processing and third party income	**571**	243	285	1,099
Interest and other income	**512**	782	626	1,920
Royalties	**(20,925)**	(9,434)	(5,386)	(35,745)
Operating expenses	**(14,245)**	(9,659)	(11,391)	(35,295)
Transportation expenses	**(12,814)**	(9,940)	(11,220)	(33,974)
General and administrative expense	**(4,457)**	(5,233)	(3,175)	(12,865)
Interest expense	**(16,037)**	(16,262)	(13,746)	(46,045)
Foreign exchange	**8,367**	(618)	223	7,972
Other	**(31)**	(30)	22	(39)
Funds from operations [1]	**106,294**	65,972	54,164	226,430
Per share – basic [2]	**0.55**	0.35	0.29	1.19
Per share –diluted [2]	**0.48**	0.31	0.25	1.02
Net income	**30,482**	43,926	1,164	75,572
Per share – basic [2]	**0.16**	0.23	0.01	0.40
Per share – diluted [2]	**0.14**	0.20	0.01	0.34
Capital investments, net of dispositions				
Land	**1,408**	28,137	1,519	31,064
Drilling and completions	**234,879**	155,284	124,294	514,457
Facilities and equipment	**90,447**	34,172	65,806	190,425
Other	**1,689**	1,531	1,430	4,650
Total capital investments	**328,423**	219,124	193,049	740,596
Adjusted working capital [1]	**67,700**	277,222	424,581	67,700
Senior notes [3]	**784,000**	746,900	773,850	784,000
OPERATING				
Average daily production				
Oil and natural gas liquids (bbls/d)	**20,869**	14,005	11,608	15,527
Natural gas (Mmcf/d)	**89.7**	60.0	51.7	67.3
Total (boe/d)	**35,820**	23,999	20,231	26,739
Realized prices				
Oil and natural gas liquids ($/bbl)	**66.33**	73.55	73.07	70.16
Natural gas ($/mcf)	**4.62**	5.36	5.80	5.14

SELECTED QUARTERLY INFORMATION - continued

	Q4 2013	Q3 2013	Q2 2013	Q1 2013	YE 2013
FINANCIAL ($ thousands, except per share amounts)					
Oil and natural gas liquids revenues	39,900	18,110	15,745	16,817	90,572
Natural gas revenues	10,921	5,582	7,039	5,388	28,930
Total revenues	50,821	23,692	22,784	22,205	119,502
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	(5,623)	(2,486)	(2,529)	(2,141)	(12,779)
General and administrative expense	(2,052)	(2,006)	(2,175)	(1,884)	(8,117)
Interest expense	(8,970)	(8,691)	(5,051)	(194)	(22,906)
Foreign exchange	(133)	(24)	6	10	(141)
Other	7	-	-	-	7
Funds from operations (1)	23,114	4,780	9,223	13,156	50,273
Per share – basic (2)	0.14	0.03	0.06	0.08	0.30
Per share – diluted (2)	0.12	0.03	0.05	0.08	0.27
Net income (loss)	(5,625)	(955)	(8,454)	876	(14,158)
Per share – basic (2)	(0.03)	(0.01)	(0.05)	0.01	(0.08)
Per share – diluted (2)	(0.03)	(0.01)	(0.05)	0.01	(0.08)
Capital investments, net of dispositions					
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	178,238	142,185	121,436	132,469	574,328
Adjusted working capital (1)	214,877	129,586	268,137	(23,559)	214,877
Senior notes (3)	425,440	412,120	420,720	-	425,440
OPERATING					
Average daily production					
Oil and natural gas liquids (bbls/d)	6,771	3,253	2,994	3,509	4,139
Natural gas (Mmcf/d)	28.9	23.0	19.1	16.4	21.9
Total (boe/d)	11,585	7,084	6,182	6,240	7,786
Realized prices					
Oil and natural gas liquids ($/bbl)	64.05	60.52	57.78	53.25	59.96
Natural gas ($/mcf)	4.11	2.64	4.04	3.65	3.62

SELECTED QUARTERLY INFORMATION - continued

	Q4 2012	Q3 2012	Q2 2012	Q1 2012	YE 2012
FINANCIAL ($ thousands, except per share amounts)					
Oil and natural gas liquids revenues	10,994	11,308	9,269	7,047	38,618
Natural gas revenues	5,820	4,636	3,707	2,844	17,007
Total revenues	16,814	15,944	12,976	9,891	55,625
Realized hedging gain	224	520	655	404	1,803
Processing and third party income	405	485	575	568	2,033
Interest and other income	433	431	223	93	1,180
Royalties	(2,922)	(959)	(859)	(793)	(5,533)
Operating expenses	(3,233)	(2,227)	(2,204)	(2,101)	(9,765)
Transportation expenses	(641)	(625)	(503)	(400)	(2,169)
General and administrative expense	(1,808)	(1,491)	(1,324)	(1,304)	(5,927)
Interest expense	(50)	(51)	(117)	(49)	(267)
Foreign exchange	-	-	-	-	-
Other	(618)	-	-	-	(618)
Funds from operations [1]	8,604	12,027	9,422	6,309	36,362
Per share – basic [2]	0.05	0.07	0.07	0.05	0.25
Per share – diluted [2]	0.05	0.07	0.07	0.05	0.24
Net loss	(379)	(247)	(875)	(1,073)	(2,574)
Per share – basic [2]	-	-	(0.01)	(0.01)	(0.02)
Per share – diluted [2]	-	-	(0.01)	(0.01)	(0.02)
Capital investments, net of dispositions					
Land	16,775	21,461	10,916	10,584	59,736
Drilling and completions	43,007	25,545	13,169	21,196	102,917
Facilities and equipment	42,346	14,331	3,496	10,033	70,206
Other	669	477	522	442	2,110
Total capital investments	102,797	61,814	28,103	42,255	234,969
Adjusted working capital [1]	95,089	189,336	195,286	16,605	95,089
Senior notes [3]	-	-	-	-	-
OPERATING					
Average daily production					
Oil and natural gas liquids (bbls/d)	1,439	1,528	1,355	912	1,309
Natural gas (Mmcf/d)	17.3	19.4	18.9	13.3	17.2
Total (boe/d)	4,316	4,763	4,512	3,123	4,180
Realized prices					
Oil and natural gas liquids ($/bbl)	83.07	80.44	75.19	84.90	80.59
Natural gas ($/mcf)	3.66	2.60	2.15	2.36	2.70

(1) See "Non-IFRS Financial Measures"
(2) On September 8, 2014, the Company amended its articles of incorporation to divide the issued and outstanding Class A Common Voting Shares on a two-for-one basis. The share split has been reflected in the condensed interim statements for the three and nine months ended September 30, 2014 and on a retroactive basis.
(3) Senior notes as reported represent US$700.0 million principal converted to Canadian dollars at the closing exchange rate for the period end.

SEVEN GENERATIONS ENERGY LTD.

Condensed Balance Sheets

Unaudited
(thousands of Canadian dollars)

As at	Notes	**September 30 2014**	December 31 2013
Assets			
Current assets			
Cash and cash equivalents	4	**202,991**	310,737
Accounts receivable		**62,264**	30,500
Risk management contracts	12	**14,527**	-
Deposits and prepaid expenses		**6,956**	2,579
		286,738	343,816
Risk management contracts	12	**819**	-
Property, plant and equipment	5	**1,727,567**	1,060,387
Goodwill		**4,010**	4,010
		2,019,134	1,408,213
Liabilities			
Current liabilities			
Outstanding cheques in excess of bank balances		**6,339**	3,252
Accounts payable and accrued liabilities		**198,172**	125,687
Risk management contracts	12	**-**	2,646
Current portion of deferred credits		**123**	118
		204,634	131,703
Senior notes	7	**785,830**	414,525
Deferred credits		**1,004**	1,048
Decommissioning liabilities	8	**45,262**	23,656
Deferred income taxes		**41,304**	9,328
		1,078,034	580,260
Equity			
Share capital	9	**824,511**	790,064
Contributed surplus	9	**48,754**	45,626
Retained earnings (deficit)		**67,835**	(7,737)
		941,100	827,953
		2,019,134	1,408,213

See accompanying notes to the condensed financial statements

SEVEN GENERATIONS ENERGY LTD.

Condensed Statements of Income (Loss) and Comprehensive Income (Loss)

Unaudited
(thousands of Canadian dollars, except per share amounts)

	Notes	Three months ended September 30 **2014**	2013	Nine months ended September 30 **2014**	2013
Revenues					
Oil and natural gas sales		**165,501**	23,692	**391,828**	68,681
Royalties		**(20,925)**	(2,227)	**(35,745)**	(4,665)
		144,576	21,465	**356,083**	64,016
Risk management contracts					
Realized gain (loss)	12	**(148)**	17	**(12,426)**	230
Unrealized gain (loss)	12	**33,390**	(765)	**17,993**	(1,321)
Interest and third party income		**1,083**	1,007	**3,019**	2,268
		178,901	21,724	**364,669**	65,193
Expenses					
Operating		**14,245**	4,502	**35,295**	12,190
Transportation		**12,814**	2,486	**33,974**	7,156
General and administrative	10	**4,457**	2,006	**12,865**	6,065
Depletion, depreciation and amortization		**46,927**	8,104	**101,477**	25,213
Stock based compensation	5	**3,544**	3,667	**8,053**	8,004
Loss (gain) on disposition of assets		**281**	-	**(3,239)**	-
		82,268	20,765	**188,425**	58,628
Operating income		**96,633**	959	**176,244**	6,565
Finance expense	11	**16,338**	9,193	**46,583**	14,883
Foreign exchange loss (gain)	13	**33,059**	(7,137)	**22,113**	157
Income (loss) before taxes		**47,236**	(1,097)	**107,548**	(8,475)
Taxes					
Deferred income tax expense (recovery)		**16,754**	(142)	**31,976**	58
Net income (loss) and comprehensive income (loss) for the period		**30,482**	(955)	**75,572**	(8,533)
Net income (loss) per share	9				
Basic		**0.16**	(0.01)	**0.40**	(0.05)
Diluted		**0.14**	(0.01)	**0.34**	(0.05)

See accompanying notes to the condensed financial statements

SEVEN GENERATIONS ENERGY LTD.

Condensed Statements of Changes in Equity

Unaudited
(thousands of Canadian dollars)

	Notes	Share capital	Contributed surplus	Retained earnings (deficit)	Total
Balance at December 31, 2012		545,057	32,581	6,421	584,059
Net loss		-	-	(8,533)	(8,533)
Stock based compensation	9	-	9,119	-	9,119
Value attributed to modification of stock options and performance warrants	9	-	2,076	-	2,076
Exercise of stock options	9	1,383	(518)	-	865
Exercise of performance warrants	9	2,167	(428)	-	1,739
Balance at September 30, 2013		**548,607**	**42,830**	**(2,112)**	**589,325**
Balance at December 31, 2013		790,064	45,626	(7,737)	827,953
Net income		-	-	75,572	75,572
Stock based compensation	9	-	11,952	-	11,952
Exercise of stock options	9	15,303	(5,538)	-	9,765
Exercise of performance warrants	9	19,144	(3,286)	-	15,858
Balance at September 30, 2014		**824,511**	**48,754**	**67,835**	**941,100**

See accompanying notes to the condensed financial statements

SEVEN GENERATIONS ENERGY LTD.

Condensed Statements of Cash Flows

Unaudited
(thousands of Canadian dollars)

	Notes	Three months ended September 30 **2014**	Three months ended September 30 2013	Nine months ended September 30 **2014**	Nine months ended September 30 2013
Operating activities					
Net income (loss) for the period		**30,482**	(955)	**75,572**	(8,533)
Deferred income tax expense (recovery)		**16,754**	(142)	**31,976**	58
Depletion, depreciation and amortization		**46,927**	8,104	**101,477**	25,213
Unrealized loss (gain) on risk management contracts	12	**(33,390)**	765	**(17,993)**	1,321
Stock based compensation	9	**3,544**	3,667	**8,053**	8,004
Amortization of premium and debt issue costs	11	**12**	295	**(352)**	448
Accretion	11	**289**	207	**890**	499
Loss (gain) on disposition of assets		**281**	-	**(3,239)**	-
Unrealized foreign exchange loss (gain)		**41,426**	(7,161)	**30,085**	149
Decommissioning expenditures		**-**	-	**(206)**	-
Other		**(31)**	-	**(39)**	-
Changes in non-cash working capital	13	**11,776**	9,886	**(4,982)**	13,972
Cash provided by operating activities		**118,070**	14,666	**221,242**	41,131
Financing activities					
Issue of senior notes	7	**-**	-	**356,342**	404,960
Debt issue costs	7	**-**	293	**(9,840)**	(11,147)
Issue of common shares	9	**16,811**	-	**25,623**	2,604
Cash provided by investing activities		**16,811**	293	**372,125**	396,417
Investing activities					
Property, plant and equipment additions		**(328,423)**	(142,185)	**(740,596)**	(396,090)
Changes in non-cash working capital	13	**46,936**	22,134	**40,637**	28,815
Cash used in investing activities		**(281,487)**	(120,051)	**(699,959)**	(367,275)
Foreign exchange on cash held in foreign currencies		**(3,367)**	(1,607)	**(4,241)**	6,948
Increase (decrease) in cash and cash equivalents		**(149,973)**	(106,699)	**(110,833)**	77,221
Cash and cash equivalents, beginning of period		**346,625**	330,125	**307,485**	146,205
Cash and cash equivalents, end of period		**196,652**	223,426	**196,652**	223,426
Cash and cash equivalents are comprised of:					
Cash and cash equivalents		**202,991**	224,873	**202,991**	224,873
Outstanding cheques in excess of bank balances		**(6,339)**	(1,447)	**(6,339)**	(1,447)
		196,652	223,426	**196,652**	223,426
Supplementary information for operating activities – cash payments					
Interest paid		**1,200**	117	**27,897**	946
Income taxes paid		**-**	-	**-**	-

Supplementary disclosure of cash flow information (Note 13)

See accompanying notes to the condensed financial statements

Notes to Condensed Financial Statements

Unaudited
(all tabular amounts in thousands of Canadian dollars, except share, per share and price information)

For the three and nine months ended September 30, 2014 and 2013

1. REPORTING ENTITY

Seven Generations Energy Ltd. ("Seven Generations" or the "Company") is incorporated under the *Canada Business Corporations Act*. Seven Generations is a Canadian company focused on exploration, development and production of oil and natural gas in western Canada. Seven Generations' principal place of business is located at 300, 140 – 8th Avenue S.W., Calgary, Alberta T2P 1B3.

Subsequent to period end, the Company closed its initial public offering (Note 15) and listed its Class A Common Voting Shares on the Toronto Stock Exchange under the symbol "VII".

2. BASIS OF PREPARATION

These condensed financial statements (the "financial statements") have been prepared in accordance with IAS 34 "Interim Financial Reporting" using policies consistent with International Financial Reporting Standards ("IFRS"). These financial statements do not include all the required annual disclosure as prescribed by IFRS and should be read in conjunction with the Company's annual audited financial statements for the year ended December 31, 2013. The Company's accounting policies are unchanged compared to December 31, 2013 except as outlined in Note 3. The use of estimates and judgments is also consistent with the December 31, 2013 financial statements.

The financial statements were approved and authorized for issue by the Board of Directors on November 12, 2014.

Certain comparative figures for prior periods have been reclassified to conform to the current period's presentation.

On September 8, 2014, the Company amended its articles of incorporation to divide the issued and outstanding Class A Common Voting Shares on a two-for-one basis. The Class B Common Non-Voting Shares were not divided. Options and Performance Warrants issued prior to the completion of the initial public offering (Note 15) will continue to be exercisable into the same number of Class B Common Non-Voting Shares. As a result of this division of the Class A Common Voting Shares, Class B Common Non-Voting Shares may now be converted, at the option of the holder of Class B Common Non-Voting Shares or the Company, on the basis of one Class B Common Non-Voting Share for two Class A Common Voting Shares. Class A Common Voting Shares and per share information included in these financial statements reflects the stock split on a retroactive basis.

3. CHANGES IN ACCOUNTING POLICIES

As of January 1, 2014, the Company adopted several new IFRS interpretations and amendments in accordance with the transitional provisions of each standard. A brief description of each new accounting policy and its impact on the Company's financial statements is provided below.

IAS 36 "Impairment of Assets" has been amended to reduce the circumstances in which the recoverable amount of cash generating units is required to be disclosed and clarify the disclosures required when an impairment loss has been recovered or reversed in the period. The retrospective adoption of these amendments will only impact the Company's disclosures in the notes to the financial statements in periods when an impairment loss or impairment reversal is recognized.

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Future Accounting Policy Changes

In February 2014, the IASB tentatively decided to require an entity to apply IFRS 9 "Financial Instruments" for annual periods beginning on or after January 1, 2018. IFRS 9 is still available for early adoption. The impact of the standard on the Company's financial statements will not be known until changes are finalized.

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4. CASH AND CASH EQUIVALENTS

As at	**September 30, 2014**	December 31, 2013
Cash	**595**	4,329
Government treasury bills bearing interest at a weighted average rate of 0.5% (December 31, 2013 – 0.7%) (1)	**202,396**	306,408
	202,991	310,737

(1) Includes term deposit balance of $97.4 million (US$87.0 million) (December 31, 2013 – $61.7 million (US$58.0 million)).

5. PROPERTY, PLANT AND EQUIPMENT

	Oil and natural gas properties	**Other fixed assets**	**Total**
Cost			
Balance at December 31, 2013	1,157,596	4,123	1,161,719
Additions	773,242	1,596	774,838
Dispositions	(6,181)	-	(6,181)
Balance at September 30, 2014	**1,924,657**	**5,719**	**1,930,376**
Accumulated depletion, depreciation and amortization			
Balance at December 31, 2013	100,600	732	101,332
Depletion, depreciation and amortization expense	100,744	733	101,477
Balance at September 30, 2014	**201,344**	**1,465**	**202,809**
Net book value			
Balance at December 31, 2013	1,056,996	3,391	1,060,387
Balance at September 30, 2014	**1,723,313**	**4,254**	**1,727,567**

As at September 30, 2014, the calculation for depletion included an estimated $7.6 billion (September 30, 2013 – $2.8 billion) for future development capital associated with undeveloped estimated recoverable proved plus probable reserves and excluded $140.8 million (September 30, 2013 – $143.0 million) for the cost of undeveloped land for which no recoverable reserves have been assigned and for other capital projects not yet in use.

During the three and nine months ended September 30, 2014, the Company capitalized $2.5 million and $6.7 million (three and nine months ended September 30, 2013 – $1.9 million and $4.8 million) of general and administrative expenses based on direct salaries and benefits paid to exploration and development personnel specifically related to capital activities, including $1.7 million and $3.9 million (three and nine months ended September 30, 2013 – $1.0 million and $3.2 million) related to stock based compensation.

During the nine months ended September 30, 2014, the Company closed asset swap arrangements of non-producing assets. For purposes of determining the gain on disposition, the estimated fair market value was based on the fair value of the asset received. For the three months ended September 30, 2014, losses were recorded related to expired mineral leases. The Company recorded a gain of $3.2 million on the assets disposed of for the nine months ended September 30, 2014.

6. BANK DEBT

On September 15, 2014, the Company and its lending syndicate agreed to an amendment to the senior secured revolving credit arrangement (the “credit facility”) that increased the borrowing capacity from $150.0 million to $480.0 million and extended the maturity date of the credit facility to September 2017. The credit facility is subject to a redetermination of the borrowing base semi-annually and is secured by a floating charge over the Company’s assets. The credit facility bears interest rates based on a pricing grid that increases or decreases based on the ratio of indebtedness to earnings before interest, taxes, depreciation, depletion and amortization. The credit facility also includes standby fees on balances not drawn.

During the three and nine months ended September 30, 2014, no amounts were drawn on the credit facility. During the year ended December 31, 2013, the Company borrowed up to $30.7 million on the credit facility for a period of one week. As at September 30, 2014 and December 31, 2013, there was no balance outstanding on the credit facility.

7. SENIOR NOTES

	Nine months ended September 30, 2014	Year ended December 31, 2013
Balance, beginning of period	**414,525**	-
Issuance of debt	**356,342**	404,960
Debt issue costs	**(9,840)**	(11,201)
Foreign exchange loss	**25,155**	19,958
Amortization of premium and debt issue costs	**(352)**	808
Balance, end of period	**785,830**	414,525

On February 5, 2014, the Company closed a private placement of US$300.0 million of senior unsecured notes issued under a supplemental indenture to the indenture governing the terms of the US$400.0 million of senior unsecured notes issued on May 10, 2013. The February 2014 notes were issued at 107% of par, resulting in gross proceeds to the Company of US$321.0 million.

8. DECOMMISSIONING LIABILITIES

	Nine months ended September 30, 2014	Year ended December 31, 2013
Balance, beginning of period	**23,656**	21,298
Liabilities incurred	**15,548**	2,621
Changes in estimated discount rates (1)	**2,746**	(3,679)
Changes in estimates (2)	**2,628**	2,683
Decommissioning expenditures	**(206)**	-
Accretion	**890**	733
Balance, end of period	**45,262**	23,656

(1) The Bank of Canada's long-term risk-free bond rate of 2.6 percent (December 31, 2013 - 3.2 percent) and an inflation rate of 2.0 percent (December 31, 2013 – 2.0 percent) were used to calculate the present value of the decommissioning liabilities at September 30, 2014.
(2) Changes in the status of wells and the estimated costs of abandonment and reclamation are factors resulting in a change in estimate.

9. EQUITY

Authorized

Unlimited number of Class A Common Voting Shares
Unlimited number of Class B Common Non-Voting Shares
Unlimited number of A, B, C, and D Preferred Shares
Unlimited number of Special Voting Shares

On May 29, 2014, shareholders approved a resolution to amend the Company's Articles of Incorporation to allow holders of Class B Common Shares to convert into Class A Common Shares on a 1 for 1 basis.

On September 8, 2014, the Company amended its articles of incorporation to divide the issued and outstanding Class A Common Voting Shares on a two-for-one basis. As a result of this division of the Class A Common Voting Shares, Class B Common Non-Voting Shares may now be converted, at the option of the holder of Class B Common Non-Voting Shares or the Company on the basis of one Class B Common Non-Voting Share for two Class A Common Voting Shares (on a post-division basis).

The share split has been reflected in the condensed interim statements for the three and nine months ended September 30, 2014 on a retroactive basis for the Class A Common Voting Shares and per share information.

Issued and Outstanding

	Nine months ended September 30, 2014		Year ended December 31, 2013	
	Number (000s)	**Amount**	Number (000s)	Amount
Class A Common Voting Shares				
Balance, beginning of period	**185,420**	**783,514**	165,340	542,057
Issued for cash	**-**	**-**	20,080	250,992
Share issue costs, net of deferred tax	**-**	**-**	-	(9,535)
Conversion of Class B Common Non-Voting Shares (1)	**6,851**	**35,013**	-	-
Balance, end of period	**192,271**	**818,527**	185,420	783,514

	Nine months ended September 30, 2014		Year ended December 31, 2013	
	Number (000s)	**Amount**	Number (000s)	Amount
Class B Common Non-Voting Shares				
Balance, beginning of period	**966**	**6,550**	600	3,000
Issued on exercise of stock options	**1,770**	**9,765**	173	865
Issued on exercise of performance warrants	**1,505**	**15,858**	193	1,739
Transfer from contributed surplus on exercise of stock options and performance warrants	**-**	**8,824**	-	946
Conversion to Class A Common Voting Shares (1)	**(3,425)**	**(35,013)**	-	-
Balance, end of period	**816**	**5,984**	966	6,550

(1) Reflects number of Class B Common Non-Voting shares converted into one-for-two Class A Common Voting Shares.

Compensation Plans

On August 27, 2014, the Board adopted a Performance and Restricted Share Unit ("PRSU") Plan and a Deferred Share Unit ("DSU") Plan. The maximum number of Class A Common Voting Shares that may be issued to officers and employees under the PRSU Plan is 1,000,000. Each Share Unit issued under the PRSU Plan will grant to the holder the right to receive a Class A Voting Common Share or, in certain circumstances, the cash equivalent of a Class A Common Share, based on the achievement of certain performance criteria. The vesting schedule of the PRSUs will be determined at the discretion of the Compensation Committee of the Board. The maximum number of Class A Common Voting Shares that may be issued to non-executive directors under the DSU Plan is 600,000. Each DSU may be redeemed for a Class A Common Voting Share issued by the Company from treasury. The vesting schedule of the DSUs will be determined at the discretion of the Compensation Committee, but generally in the case of DSUs granted in lieu of director retainers or as annual incentives, the DSUs vest immediately on the award date.

Stock Options

The Company has issued stock options to its directors, officers, and employees to acquire up to 6.2 million Class B Common Non-Voting Shares. These stock options were granted under the stock option plan contained in the Amended and Restated Shareholders' Agreement ("USA") effective while Seven Generations was a private company. The stock options have a seven-year term from the date of grant and vest over a period of three years. After the closing of the initial public offering (Note 15), no additional stock options may be granted under this plan.

In anticipation of an initial public offering, the Company's stock option plan was amended and restated on August 27, 2014 (the "New Plan"). Stock options awarded after the closing of the initial public offering will be issued under the New Plan. These stock options will be exercisable for Class A Common Voting Shares rather than Class B Common Non-Voting Shares. The stock options will vest over a period of three years, or as otherwise set out by the Board in the applicable grant agreement, and will have a maximum term of ten years. The maximum number of Class A Common Voting Shares issuable under the New Plan and other share based compensation arrangements (excluding the performance warrants) must not exceed 10% of the aggregate of the number of outstanding Class A Common Voting Shares plus two times the number of outstanding Class B Common Non-Voting Shares.

Pursuant to the USA, the Company committed to grant up to 10% of the number of issued and outstanding shares with each stock option exercisable into a Class B Common Non-Voting Share at $5.00 per share. At the date of the USA, the Company had committed to issue 5,978,000 stock options, based on the number of issued shares under its initial financing. Per the USA, immediately prior to the completion of a change of control, liquidity event or qualified initial public offering (the "Liquidity Event"), the Company would be obligated to make whole, for the after-tax economic value, option holders who held options with exercise prices greater than $5.00 per share. Based on the exercise prices of options issued to date, the Company has an obligation, triggered by a Liquidity Event, of approximately $10.0 million. The liability will be settled by the issue of Class A Common Voting Shares to provide the equivalent after-tax economic value of this obligation. The shares to be issued will be determined based on the fair market value prevailing as of the date of the issuance.

The following table sets forth a reconciliation of stock options exercisable into Class B Common Non-Voting Shares:

	Number of options (000s)	Weighted average exercise price ($)
Balance at January 1, 2013	5,825	6.04
Granted	1,128	11.41
Exercised	(173)	5.00
Forfeited	(67)	5.71
Balance at December 31, 2013	6,713	6.97
Granted	1,373	33.08
Exercised	(1,770)	5.52
Forfeited	(131)	8.93
Balance at September 30, 2014	6,185	13.07

A summary of stock options outstanding and exercisable into Class B Common Non-Voting Shares at September 30, 2014 is as follows:

	Options Outstanding		Options Vested	
Exercise price ($)	Number of options (000s)	Weighted average remaining life (years)	Number of options (000s)	Weighted average remaining life (years)
5.00	2,921	2.9	2,897	2.9
11.00	1,895	5.3	869	5.1
25.00	244	6.4	-	-
35.00	961	6.7	-	-
35.00 (1)	164	6.9	-	-
	6,185	4.4	3,766	3.4

(1) As at September 30, 2014, the exercise price was yet to be determined. Based on the share price of the Company's initial public offering (Note 15), the exercise price has been set at $36.00.

The fair value of stock options granted was estimated using a Black-Scholes pricing model with the following weighted average assumptions:

	Three months ended September 30		Nine months ended September 30	
	2014	2013	**2014**	2013
Fair value of options granted ($/option)	**16.32**	4.32	**15.47**	4.10
Risk-free interest rate (%)	**1.34**	1.24	**1.40**	1.06
Expected life (years)	**4.0**	2.4	**3.9**	2.1
Expected forfeiture rate (%)	**3.0**	3.0	**3.0**	3.0
Expected volatility (%)	**60**	65	**60**	65
Expected dividend yield (%)	**-**	-	-	-

During the three months ended September 30, 2013, the stock options granted in 2008 were amended to extend the expiry date by one year in order to realign compensation with the Company's business plan. The incremental fair value of the stock option modifications of $0.4 million was expensed in the three months ended September 30, 2013. The fair value was estimated using a Black-Scholes pricing model with the following weighted average assumptions:

Fair value of option modification ($/option)	0.22
Risk-free interest rate (%)	1.22
Expected life (years)	2.5
Expected forfeiture rate (%)	3.0
Expected volatility (%)	65
Expected dividend yield (%)	-

Performance Warrants

The Company has issued performance warrants to its directors, officers, and employees to acquire up to 13.1 million Class B Common Non-Voting Shares. The performance warrants have a seven-year term from the date of grant and vest over a period of five years. As of September 30, 2014, no more performance warrants can be issued.

Pursuant to the USA, the Company committed to grant up to 14,945,000 performance warrants exercisable at $7.50, $9.00, $10.50, $12.00 and $13.50 per share. Per the USA, immediately prior to the completion of a Liquidity Event, the Company would be obligated to make whole, for the after-tax economic value, warrant holders who held warrants with exercise prices greater than those specified in the USA as well as for warrants which have not yet been issued. Based on the number and exercise prices of warrants issued to date, the Company has an obligation for these warrants, triggered by a Liquidity Event, of approximately $26.0 million. The liability will be settled by the issue of Class A Common Voting Shares to provide the equivalent after-tax economic value of this obligation. The shares to be issued will be determined based on the fair market value prevailing as of the date of the issuance.

The following table sets forth a reconciliation of performance warrants exercisable into Class B Common Non-Voting Shares:

	Number of warrants (000s)	Weighted average exercise price ($)
Balance at January 1, 2013	13,896	10.66
Granted	1,118	12.01
Exercised	(193)	9.00
Forfeited	(408)	10.56
Balance at December 31, 2013	14,413	10.77
Granted	675	33.30
Exercised	(1,506)	10.54
Forfeited	(488)	12.20
Balance at September 30, 2014	13,094	11.95

A summary of performance warrants outstanding and exercisable into Class B Common Non-Voting Shares at September 30, 2014 is as follows:

	Warrants Outstanding		Warrants Vested	
Weighted average exercise price ($)	Number of warrants (000s)	Weighted average remaining life (years)	Number of warrants (000s)	Weighted average remaining life (years)
10.50	9,623	2.8	7,390	2.6
11.70	2,804	5.1	894	5.0
25.00	47	6.3	-	-
35.00	620	6.7	-	-
	13,094	3.5	8,284	2.8

The fair value of performance warrants granted was estimated using a Black-Scholes pricing model with the following weighted average assumptions:

	Three months ended September 30		Nine months ended September 30	
	2014	2013	**2014**	2013
Fair value of warrants granted ($/warrant)	**-**	4.26	**17.73**	3.90
Risk-free interest rate (%)	**-**	1.23	**1.43**	1.05
Expected life (years)	**-**	2.4	**5.0**	2.1
Expected forfeiture rate (%)	**-**	3.0	**3.0**	3.0
Expected volatility (%)	**-**	65	**60**	65
Expected dividend yield (%)	**-**	-	**-**	-

During the three months ended September 30, 2013, the performance warrants granted in 2008 were amended to extend the expiry date by one year in order to realign compensation with the Company's business plan. The incremental fair value of the performance warrant modifications of $1.7 million was expensed in the three months ended September 30, 2013. The fair value was estimated using a Black-Scholes pricing model with the following weighted average assumptions:

Fair value of option modification ($/option)	0.42
Risk-free interest rate (%)	1.22
Expected life (years)	2.5
Expected forfeiture rate (%)	3.0
Expected volatility (%)	65
Expected dividend yield (%)	-

The Company recorded stock based compensation expense of $3.5 million and $8.1 million relating to the stock options and performance warrants for the three and nine months ended September 30, 2014 (three and nine months ended September 30, 2013 - $3.7 million and $8.0 million), respectively. During the nine months ended September 30, 2014, $3.9 million of direct and incremental stock based compensation expense was capitalized to property, plant and equipment (nine months ended September 30, 2013 - $3.2 million).

Per Share Amounts

Basic and diluted per share amounts have been calculated based on the following:

	Three months ended September 30 (1)		Nine months ended September 30 (1)	
	2014	2013	**2014**	2013
Net income (loss) for the period	**30,482**	(955)	**75,572**	(8,533)
Weighted average number of common shares (000s) (1)				
Shares outstanding, beginning of period	**187,352**	167,272	**187,352**	166,540
Shares issued	**5,108**	-	**2,208**	410
Basic	**192,460**	167,272	**189,560**	166,950
Effect of outstanding stock options and performance warrants(1),(2)	**29,691**	5,965	**32,538**	5,378
Diluted	**222,151**	173,237	**222,098**	172,328

(1) Reflects two-for-one share split.
(2) Only dilutive stock options and performance warrants have been included above.

10. GENERAL AND ADMINISTRATIVE EXPENSES

	Three months ended September 30		Nine months ended September 30	
	2014	2013	**2014**	2013
Personnel	**2,902**	1,784	**9,321**	5,428
Other	**2,426**	899	**6,336**	2,698
Gross expenses	**5,328**	2,683	**15,657**	8,126
Capitalized salaries and benefits	**(650)**	(516)	**(2,138)**	(1,600)
Operating overhead recoveries	**(221)**	(161)	**(653)**	(461)
	4,457	2,006	**12,865**	6,065

11. FINANCE EXPENSE

	Three months ended September 30		Nine months ended September 30	
	2014	2013	**2014**	2013
Interest on senior notes	**15,724**	8,568	**44,760**	13,378
Revolving credit facility fees and other	**313**	123	**1,285**	558
Amortization of premium and debt issue costs	**12**	295	**(352)**	448
Accretion	**289**	207	**890**	499
	16,338	9,193	**46,583**	14,883

12. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT CONTRACTS

Financial instrument classification and measurement

The Company's financial instruments include cash and cash equivalents, outstanding cheques in excess of bank balances, accounts receivable, 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, outstanding cheques in excess of bank balances and risk management contracts and the credit facility. The credit facility has a floating rate of interest and therefore the carrying value approximates the fair value. 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. The fair value of senior notes is approximately $849,000 as at September 30, 2014 (December 31, 2013 –$434,000).

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 and outstanding cheques in excess of bank balances are classified as Level 1 measurements. Risk management contracts, the credit facility 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 three and nine months ended September 30, 2014 or the year ended December 31, 2013. The carrying value of the Company's accounts receivable, accounts payable and accrued liabilities approximate their fair values due to the short-term maturity of these instruments.

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 September 30, 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	15,979	(1,452)	14,527
Long-term asset	914	(95)	819
Current liability	(1,452)	1,452	-
Long-term liability	(95)	95	-
Net position	15,346	-	15,346

As at December 31, 2013	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	68	(68)	-
Current liability	(2,714)	68	(2,646)
Net position	(2,646)	-	(2,646)

Risk management contracts

The following risk management contracts were outstanding at September 30, 2014:

Commodity	**Term**	**Contract**	**Volume**	**Average Price/Unit**
Natural gas	Oct 1, 2014 - Dec 31, 2014	Fixed Price	41,000 GJ/d	CDN$3.91
Natural gas	Oct 1, 2014 - Dec 31, 2014	Costless Collar	24,000 GJ/d	CDN$4.00 - $5.00
Natural gas	Jan 1, 2015 - Dec 31, 2015	Fixed Price	8,500 GJ/d	CDN$3.82
Natural gas	Jan 1, 2015 - Mar 31, 2015	Fixed Price	7,000 GJ/d	CDN$4.20
Natural gas	Jan 1, 2015 - Mar 31, 2015	Costless Collar	58,000 GJ/d	CDN$4.07 - $5.24
Natural gas	Apr 1, 2015 - Jun 30, 2015	Fixed Price	25,000 GJ/d	CDN$3.86
Natural gas	Apr 1, 2015 - Dec 31, 2015	Fixed Price	30,000 GJ/d	CDN$3.91
Natural gas	Jul 1, 2015 - Sept 30, 2015	Fixed Price	5,000 GJ/d	CDN$3.86
Natural gas	Oct 1, 2015 - Dec 31, 2015	Fixed Price	10,000 GJ/d	CDN$3.78
Oil	Oct 1, 2014 - Dec 31, 2014	Fixed Price	7,400 bbls/d	CDN$104.86
Oil	Oct 1, 2014 - Dec 31, 2014	Costless Collar	3,400 bbls/d	CDN$100.00-$110.98
Oil	Jan 1, 2015 - Dec 31, 2015	Fixed Price	1,100 bbls/d	CDN$99.81
Oil	Jan 1, 2015 - Mar 31, 2015	Fixed Price	10,100 bbls/d	CDN$102.57
Oil	Apr 1, 2015 - Jun 30, 2015	Fixed Price	10,500 bbls/d	CDN$102.43
Oil	Jul 1, 2015 - Sept 30, 2015	Fixed Price	6,500 bbls/d	CDN$101.44
Oil	Oct 1, 2015 - Dec 31, 2015	Fixed Price	1,000 bbls/d	CDN$100.75

During the three and nine months ended September 30, 2014, the Company's risk management contracts resulted in a realized loss of $0.1 million and $12.4 million (three and nine months ended September 30, 2013 – realized gains of $nil and $0.2 million) and an unrealized gain of $33.4 million and $18.0 million (three and nine months ended September 30, 2013 – unrealized loss of $0.8 million and $1.3 million, respectively).

Subsequent to September 30, 2014, the Company entered into new hedging contracts as follows:

Commodity	**Term**	**Contract**	**Volume**	**Average Price/Unit**
Natural gas	Jul 1, 2015 – Dec 31, 2015	Fixed Price	20,000 GJ/d	CDN$3.46
Natural gas	Oct 1, 2015 - Dec 31, 2015	Fixed Price	5,000 GJ/d	CDN$3.75
Natural gas	Jan 1, 2016 – Mar 31, 2016	Fixed Price	17,500 GJ/d	CDN$3.79
Oil	Apr 1, 2015 – Jun 30, 2015	Fixed Price	500 bbls/d	CDN$96.33

13. SUPPLEMENTARY INFORMATION

Change in non-cash working capital

	Three months ended September 30		Nine months ended September 30	
	2014	2013	**2014**	2013
Accounts receivable	**(16,018)**	(2,097)	**(31,764)**	(2,282)
Deposits and prepaid expenses	**(2,625)**	(93)	**(4,377)**	(1,907)
Accounts payable and accrued liabilities	**77,355**	34,210	**71,796**	46,976
	58,712	32,020	**35,655**	42,787
Relating to:				
Operating activities	**11,776**	9,886	**(4,982)**	13,972
Investing activities	**46,936**	22,134	**40,637**	28,815

Foreign exchange loss (gain)

	Three months ended September 30		Nine months ended September 30	
	2014	2013	**2014**	2013
Unrealized foreign exchange loss (gain)	**38,059**	(8,768)	**25,844**	7,097
Realized foreign exchange loss (gain)	**(5,000)**	1,631	**(3,731)**	(6,940)
	33,059	(7,137)	**22,113**	157

14. COMMITMENTS

The following table lists the Company's estimated material contractual commitments at September 30, 2014:

	Total	Less than 1 year	1-3 years	4-5 years	Thereafter
Accounts payable and accrued liabilities	**198,170**	198,170	-	-	-
Senior notes (1)	**784,000**	-	-	-	784,000
Interest on senior notes (1)	**363,826**	64,681	129,360	129,360	40,425
Firm transportation and processing agreements (2)	**1,039,893**	7,554	267,142	283,391	481,806
Operating leases (3)	**14,769**	2,061	4,014	3,277	5,417
Estimated contractual obligations	**2,400,658**	272,466	400,516	416,028	1,311,648

(4) Balances denominated in US dollars have been translated at the September 30, 2014 exchange rate.
(5) Seven Generations has entered into an agreement with a midstream company for firm transportation and processing services, of which the above estimates for timing of payments are subject to completion of certain pipeline and facility upgrades by the counterparty transportation company.
(6) The Company is committed under operating leases for office premises until 2023.

Effective August 27, 2014, the Company entered into an agreement to have a third party provide a 24-hour dedicated crew for hydraulic fracturing. The agreement has an initial term of one year. The Company may terminate the agreement on less than 60 days' notice and payment to the third party of an amount equal to $50,000 for each day less than 60 days that notice of the termination is given.

15. SUBSEQUENT EVENTS

On October 29, 2014, the Company signed an underwriting agreement and filed a final prospectus for an initial public offering ("IPO") to raise gross proceeds of $810 million through the issuance of 45 million Class A Common Voting Shares at a price of $18.00 per common share (the "IPO price"). The underwriters' commission was 5% of the gross proceeds of the IPO. The expenses of the IPO, excluding the underwriters' commission, are estimated to be approximately $2.5 million, and will be paid by the Company out of the proceeds of the treasury offering. The IPO closed on November 5, 2014. Upon completion of the IPO, the Company had 244.0 million Class A Common Voting Shares and 0.8 million Class B Common Non-Voting Shares outstanding. As part of the IPO, the underwriters exercised an option (the "Over- Allotment Option") for an additional 6.75 million Class A Common Voting Shares (representing 15% of the base IPO), resulting in gross proceeds of $121.5 million.

Subsequent to September 30, 2014, the Board of Directors approved a retention bonus plan for management and employees. The retention bonuses will be payable in four equal instalments payable every six months starting on May 5, 2015. Each instalment payment will be contingent upon the individual being employed by the Company on the date of payment. The maximum retention bonuses payable over the two-year period starting November 5, 2014 is approximately $6.0 million.

CORPORATE & SHAREHOLDER INFORMATION

DIRECTORS

C. Kent Jespersen
Chairman
Patrick Carlson
Chief Executive Officer
Michael Kanovsky (2) (3)
Kaush Rakhit (2) (5)
Kevin Brown (1) (4) (5)
Jeff van Steenbergen (1) (5)
Jeff Donahue (1) (3)
Dale Hohm (3) (4)
W.J. (Bill) McAdam (2) (4)

(1) Member of Governance and Nominating Committee
(2) Member of Reserves and Risk Management Committee
(3) Member of Audit and Finance Committee
(4) Member of HSE and Community Engagement Committee
(5) Member of Compensation Committee

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ENGINEERING CONSULTANTS

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AUDITORS

Deloitte LLP
Calgary, Alberta

OFFICERS

Patrick Carlson
Chief Executive Officer
Marty Proctor
President and Chief Operating Officer
Harry Cupric
Chief Financial Officer
Steve Haysom
Senior Vice President
Randy Evanchuk
Executive Vice President
Susan Targett
Vice President, Land
Barry Hucik
Vice President, Drilling
Christopher Law
Vice President, Corporate Planning
Glen Nevokshonoff
Vice President, Development
Merle Spence
Vice President, Construction and Marketing
Randy Hnatuik
Vice President, Business Development

REGISTRAR AND TRANSFER AGENT

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STOCK EXCHANGE

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