2015
ANNUAL REPORT

SEVEN GENERATIONS
ENERGY

2015 AT A GLANCE

Seven Generations Energy Ltd. is an independent, publicly-traded energy company focused on the acquisition, development and value optimization of high-quality, tight-rock, natural gas resource plays.

Seven Generations differentiates itself through its core attributes: the quality of its liquids-rich asset, large resource size, desirable location and market access, a high degree of operational control, proven and innovative technical execution and unique operating approaches.

We are committed to protecting the natural beauty of the environment and preserving its capacity for current and future generations. While we recognize that our activity and operations impact the air, water, land and natural life, we believe it is vital that we work with all our stakeholders to reduce and minimize our environmental impacts.

Our strategy

Financial Stability
Profitable growth to achieve positive free cash flow

Full-Cycle Profitability
Earning a return on capital employed across the entire commodity cycle

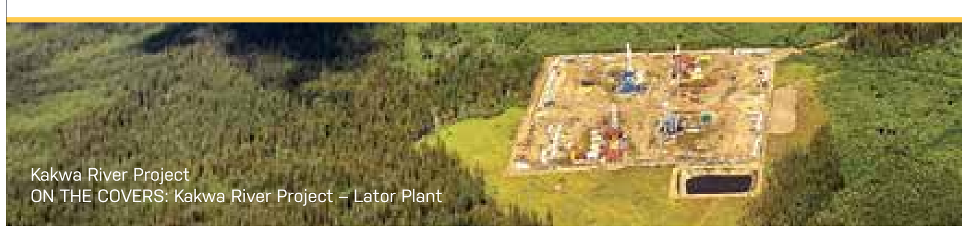
Stakeholder Interests
Recognizing that in a competitive world, only those who best serve their stakeholders can expect to survive in the long term

Innovation
Applying innovation and technology to remain among North America's lowest supply cost unconventional gas developers

Seven Generations trades on the **Toronto Stock Exchange** under the symbol **VII.**

$415 million
↑26%
FUNDS FROM OPERATIONS

$23.72
per boe
OPERATING NETBACK AFTER HEDGING



Kakwa River Project
ON THE COVERS: Kakwa River Project – Lator Plant

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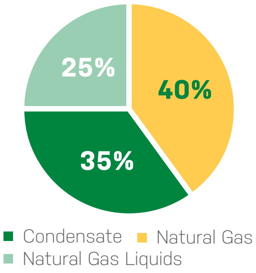
60,400 boe/d
↑94%

2015 PRODUCTION

100 to 110
thousand boe/d

2016 PRODUCTION FORECAST

Production Split



CEO'S MESSAGE

Pat Carlson,
Chief Executive Officer

Let me start by thanking our shareholders for their continued investment support and for meeting with us, providing feedback that helps us mould and adapt our business strategy to remain competitive in North America's evolving energy market. We feel privileged that our meeting schedules at investor conferences are generally full, that shareholders call or visit us at our offices and that our occasional investor field tours are filled with a variety of inquisitive guests. Investors' thoughts, input and challenges to our thinking help us evolve our strategy. Their ideas and thinking help us serve all of our stakeholders in a differentiating way, consistent with our Level 1 Policy Statement, our Code of Conduct, which is on page 15 of this report.

The way things have evolved as a public company, I get about two chances per year to write to all shareholders about our strategy – one in the autumn after we announce our budget guidance for the coming year and one in the spring through this annual report. With each report, I like to focus on business strategy. I like to leave reporting on operations and finance, except for the high level strategic implications, to my very capable colleagues who lead those functions in our leadership team – Marty Proctor, President and Chief Operating Officer and Chris Law, Chief Financial Officer. Just as my views are forged through my communication with shareholders, theirs are equally fashioned by their interactions with a variety of shareholder audiences.

In this update I would like to describe the state of our evolving thinking on the following issues:

1. Key elements of competition in the over-supplied North American gas market

2. Challenges and opportunities to expand the market for our products – turning a red ocean blue

3. 7G's resources in the context of the capacity of northwest Alberta and northeast British Columbia as a market supply region

4. Evolving expectations for social license in our operating area

1. Key elements of competition in the over-supplied North American gas market

I want to highlight some elements of the competitive environment that most profoundly affect our profitability and future potential. For those who have been following our story, some of this may be repetitive, but I hope to add new insights that contribute to an evolving vision for Seven Generations.

North America natural gas – a textbook free market

The North American natural gas market is as close to a textbook free market as reality allows. Natural gas is largely an undifferentiated commodity. For most buyers, one unit of natural gas is the same as the next. The lowest price gets the market. There are many buyers and many sellers. Competition is efficient.

Market access constraints

The ability of producers to get their products to market – market access – is defined by the availability of gathering, processing and pipeline capacity between the natural gas field and the consumer. For producers in northwest Alberta and northeast British Columbia, some market features have added a layer of complexity to their competitiveness. These include:

- Transcontinental pipelines that are in place to deliver natural gas from northwest Alberta and northeast British Columbia across most of Canada and into the U.S. markets along the West Coast and in the U.S. Midwest – the Chicago-area market;

- 7G is under contract to Alliance Pipeline to ramp up delivery from the present 250 million cubic feet per day (MMcf/d) of liquids-rich natural gas to 500 MMcf/d of liquids-rich natural gas into the Chicago-area market by late 2018. We also have 107 MMcf/d of leaner natural gas contracted on the TransCanada pipeline system to start delivery in 2018. Eastbound pipelines out of northwest Alberta and northeast British Columbia have been fully contracted in recent months forcing those wishing to contribute natural gas supply to pay a premium to use space contracted to a third party or accept less-reliable transportation service that is interruptible. Liquids pipelines out of the region are also full, which means that liquids are being shuffled via truck to find available space on the regional gathering lines; and

- Some producers have contracted aspects of their gathering and processing to midstream service providers which may limit their ability to adjust rates or optimize costs. I will elaborate on the Canadian midstream model later.

New Canadian and Alberta governments – so far, so good

The 2015 Alberta and Canadian elections brought uncertainty at the provincial and federal levels. Uncertainty also exists, in some cases, as to the costs that may arise in connection to claims made, or rights asserted, by First Nations communities. This added element of risk is probably reflected in the cost of capital and the willingness of Canadian operators to invest in development. The Alberta government's January announcement defining the basic structure of its royalty program provided producers with considerable comfort, particularly as a result of the stated desire to make returns equivalent in the present and new system, which takes effect in 2017. The new royalty formula will include a surrogate for well capital cost that more closely matches the industry's actual track record and there are provisions to file special applications for experimental well designs. This is particularly encouraging for 7G because innovation is required to remain competitive and we believe we are among the industry leaders in well design innovation.

Find a market niche – something that can be done and that most others are not focused on.

Get the best expertise – companies are built on ideas and know-how. People own that.

Diversify to increase risk tolerance with respect to key risks.

Keep control of your products and your operations until you get a fungible product to an open market.

Canada's new government has a strong focus on climate change, and Alberta's government has already announced its greenhouse gas emission reduction program. A recent gathering of Canada's prime minister and the nation's premiers provides some comfort that the federal government will stand back and let provinces administer their own schemes, provided that they do implement a mechanism on carbon emissions within a mutually agreed upon range. The recent international agreement on climate change at the December 2015 conference in Paris gives hope to British Columbia and Alberta operators that competing developers in other natural gas producing jurisdictions will soon also bear a burden for carbon dioxide and methane emissions. If revenue-neutral greenhouse gas reduction programs are implemented and gradually escalated around the world, behavior aimed at emission reductions should be encouraged, end users will bear more of the real cost associated with the use of fossil fuels, projects will be burdened similarly for emissions from their production and the industry will be transitioned towards a more sustainable outlook.

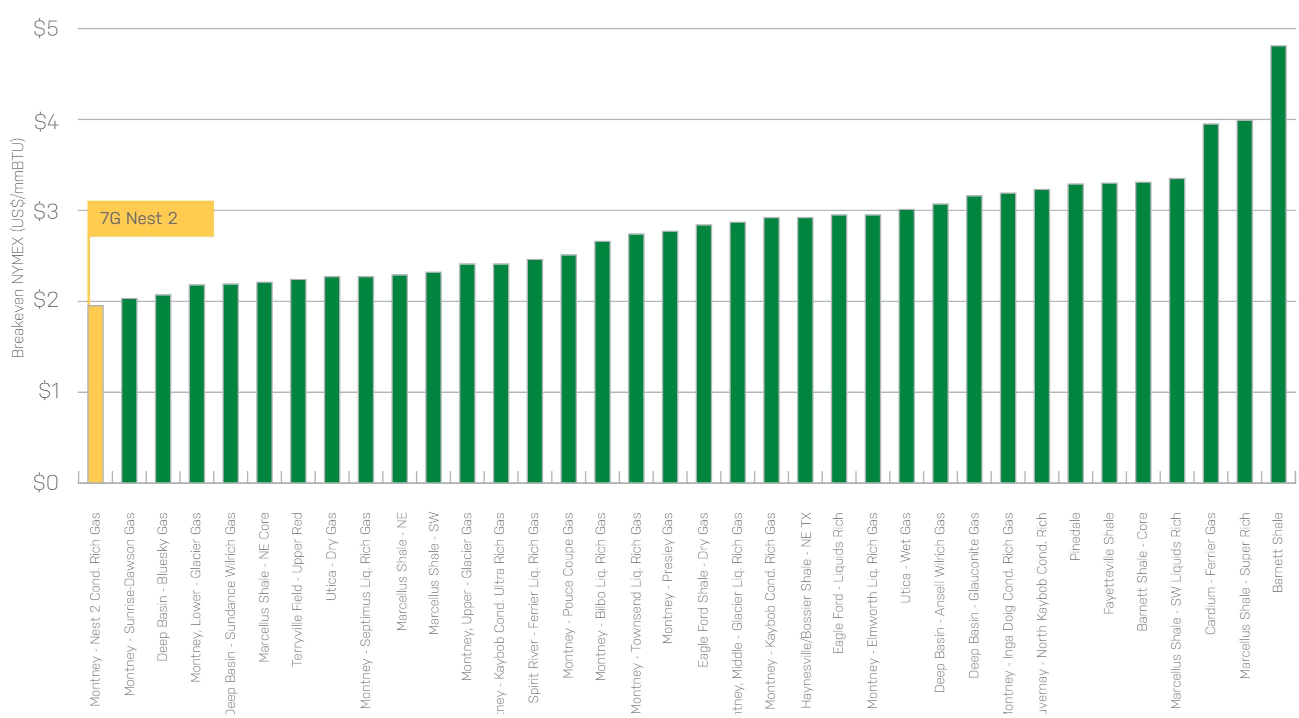
I look at it this way. As the energy industry, we are the start of a supply chain that provides consumers with many of the products that they need and want. Provided that climate change burdens are evenly applied, we will still be called upon to produce our products. The products with the least greenhouse gas emissions, from source to consumption, will gain an edge, and the industry will still be rewarded with returns for meeting consumer demand. Our challenge will be to deliver more valuable products to our customers per net tonne of carbon dioxide (CO_2) equivalent emissions. With our modern production and processing facilities, our control over our operations, our high production rate and our high resource recovery natural gas wells, I believe we are well positioned to be a net winner as the global marketplace evolves to comply with the Paris agreement.

North America's plentiful and competitive supply will continue to squeeze margins

Innovative competitors with very high quality assets and access to the traditional customers served by northwest Alberta and northeast British Columbia producers threaten to further flood our markets and put downward pressure on our profit margins. To help investors compare projects and natural gas plays, some energy market analysts publish comparisons of supply costs of various plays. Their research is calibrated to continental benchmark natural gas and oil prices – the price per million British thermal units (MMBtu) of natural gas at Henry Hub, Louisiana and the price for a barrel for West Texas Intermediate crude oil at Cushing, Oklahoma. Prices for various qualities of oil and natural gas at distinct locations across North America are based on several factors relative to the benchmark prices. They include the value of the commodity by specification, local supply and demand variations, plus the ability and cost to ship supplies between market locations. When analysts compare projects they often present a chart with bars for the array of projects that they analyze, with each play measured on a comparable set of criteria. These charts rank projects or plays according to the Henry Hub natural gas price that is required for the next unit of natural gas to be produced, provided that it meets the analyst's economic threshold, such as a 15 percent before tax internal rate of return. These plays are often sorted from the lowest cost project on the left to the highest cost on the right. The resulting profile typically takes the shape of a boot and thus we call the presentation a "supply cost boot diagram". This supply cost may also be called the threshold price or the breakeven price. This method of ranking projects by their competitiveness usually only includes the cost to add supply to an established project, not the full-cycle costs, which would also take into account processing and market access infrastructure, original cost of the resource, land costs, and sunk costs that were required for the developer to test and commercialize the play. On the next page is a typical boot diagram prepared by Credit Suisse in February 2016, using an oil price of US$40 per barrel (bbl).

"We recognize that the business environment for natural gas resource developers is rapidly evolving. Therefore it only makes sense that we adopt the notion that we must be nimble, cognizant of future possibilities, preserving of options, yet moving decisively and quickly to capture benefits for all of our stakeholders."

NYMEX ($USD/MMBtu) Breakeven* Price by Play – $40/bbl oil price



*Assumes a 15% IRR, US$40/bbl WTI, WTI less US$5/bbl for Edmonton Par, US$0.50/MMBtu AECO basis and FX of 0.75 (US$/C$).
Source: Credit Suisse Equity Research – February 1, 2016.

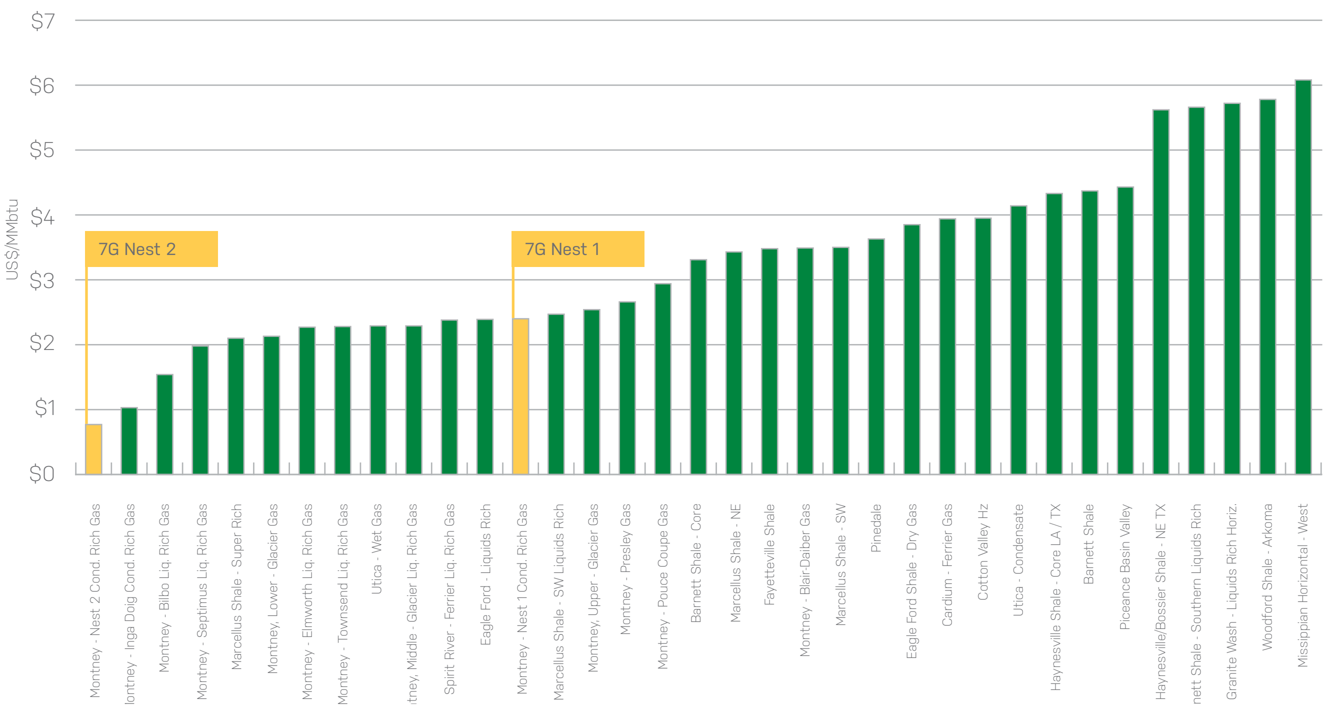
You'll see that our Nest 2 play in our Kakwa River Project, with a projected supply cost of US$1.95 per MMBtu, is ranked as having the best economics among 36 natural gas projects across North America that this particular analyst presented. These projects represent our core competitors. This supply cost boot diagram clearly illustrates our prime objective: stay at the toe of the boot.

When oil prices fall significantly, as they have in the past 22 months, our comparative economic advantage to other plays is eroded. For us, condensate is a valuable product because it is priced similar to oil and condensate is about 35 percent of our production by energy equivalence. It generates a large proportion of our revenue – more or less depending upon oil prices. In this market backdrop, we remain ranked as the most competitive, but our lead is diminished.

Credit Suisse also produced a boot diagram in August of 2015 based on an oil price of US$60/bbl, which is on page 6. In the $40 oil chart that is above, the breakeven price for the lowest cost projects, including 7G's Montney Nest 2 Condensate Rich Gas, is much higher – US$1.95 per MMBtu. The difference in price relative to the next best projects is less pronounced, 8 cents compared to 26 cents when the oil price is $60/bbl.

In an open market, like the North American natural gas market is, the market sets a price at which demand is just met at the breakeven price of the most expensive supply needed. Because the owners of the lowest cost supplies may not be willing or able to supply the entire market need, some natural gas projects that have higher than the lowest breakeven price will be called upon to supply natural gas. To continue to develop in the economic environment described in the conditions illustrated in the boot diagram, a project needs to be nearer to the toe of the boot than the project that barely meets the profitability criteria that the analyst has used.

NYMEX ($USD/MMBtu) Breakeven* Price by Play – $60/bbl oil price



*Assumes a 15% IRR, US$60/bbl WTI, WTI less US$5/bbl for Edmonton Par, US$0.50/MMBtu AECO basis and FX of 0.80 (US$/C$)
Source: Credit Suisse Equity Research – August 10, 2015.

Our target has always been to possess a project among those at the toe of the boot and to have a considerable margin on the most threatening alternatives. Some of the concerns that are brought to light upon comparative examination of these two charts are:

- The projects with the lowest breakeven price are mostly liquids-rich natural gas projects. The profitability of liquids-rich natural gas projects are strongly affected by the price of oil because some of the liquids produced are priced in the oil market. That is not to say that the oil price is the only change in Credit Suisse's two analyses, but the first chart shows five projects with a breakeven price of less than US$2.25 per MMBtu while the second chart shows seven. I believe that two factors likely contribute to this shift in supply cost.

First, the overall cost of natural gas is coming down. We attribute this economy, in part, to reduced upstream goods and services costs because of a downturn in industry activity. Despite modest growth in North American natural gas demand over recent years, the very recent downturn in activity has resulted from two events:

- The need for fewer natural gas wells to satiate decline replacement and the modest growth in demand in the natural gas market; and
- The reduction in drilling for oil targets due to collapsed oil prices. Innovation and efficiency measures, like the ones being implemented by 7G, are being applied across the natural gas industry. This has resulted in improved productivity and recovery per well and lower costs.

Second, the extra revenue that the most liquids-rich natural gas projects receive does not provide as much differential to the breakeven price when oil prices are low. In fact, there were times in the summer of 2015 when a portion of Alberta propane was selling at a negative price. That means some Alberta producers were having to pay people to take their propane volumes. While not great, we were fortunate. Propane pricing at the Conway, Kansas benchmark, which is the price we receive for our volumes extracted at Aux Sable in Illinois, continued to trade last summer in the range of US$10 to US$15 per bbl. In both markets, the natural gas liquids (NGLs) production growth has shown that it can outpace North American demand, which can result in it becoming a by-product that, at times, costs producers money to get to market.

The Supply Cost Sensitivities diagram on the following page shows a graph of two of 7G's development areas:

- Nest 2 (yellow line) is very rich in liquids and we are undertaking what we believe to be commercial development of one of the continent's lowest supply cost natural gas resources. It achieves a 20 percent internal rate of return at prices as low as oil at US$30 per bbl and US$2.20 per MMBtu. Keep in mind that supply cost is not the total cost; it is just the cost to add wells to maintain production; and

- Deep Southwest (green line) has leaner natural gas that we are still testing and have not yet started to experiment with well designs and development methods. To achieve a 20 percent internal rate of return, by our estimate from what we have learned to date, we require a natural gas price of US$4.25 per MMBtu when oil is priced at US$30 per bbl. We are not drilling and completing wells in the Deep Southwest, but if we can apply our most recent innovations and efficiencies, we would expect to achieve much improved breakeven prices and increase the potential for commercial development.

The slope of the supply cost sensitivities curve for each area suggests the high degree of sensitivity of breakeven price to liquids content. Of course that sensitivity evaporates if the liquids market is so oversupplied that NGLs are essentially given away. A fact of liquids-rich natural gas production is that the producer must find a market for all of the resulting products:

- Condensate – the best market currently is the Canadian oil sands
- Butane – a finite amount is useful to refiners and petrochemical manufacturers
- Propane – limited markets exist for this as a petrochemical feedstock and as a portable fuel for use in locations that are not served by natural gas
- Ethane – a highly valued petrochemical feedstock that is grossly oversupplied such that it is largely used as a supplement to methane in natural gas fuel

At the rate we produce these commodities, storage for any extended period of time is impractical. We must sell all of them in order to sell any of them, and at times the market for some products disappears in the wash of oversupply.

Supply Cost Sensitivities: Price required for 20% IRR

(pre-tax, management type curves, half-cycle)

Assumptions:

Sliding scale for WTI & FX; $30 US/bbl WTI @ 0.70 CAD/USD FX to $100/bbl WTI @ 0.90 CAD/USD FX. NGLs as % of WTI: C3 35%, C4 50%, Alberta C5+ 93%. Chicago gas discount $0.01 to NYMEX HH. Unit transportation costs: sales gas $1.00/Mcf. Recovered liquids: $5.80/bbl.

Nest 2: Average opex (first 3 years) $3.88, ~$6.8MM natural gas deep drilling credit pool for 2450m lateral. 15% raw gas shrink.

Deep Southwest: Average opex (first 3 years) $6.12/boe, ~$7.7MM natural gas deep drilling credit pool for 2200m lateral. 15% raw gas shrink.

Half-cycle economics: include only the cost to drill, complete, tie & equip a well. No costs for central processing, regional gathering, condensate stabilization, other infrastructure, land acquisition, corporate overheard (G&A), financing or corporate taxes are included. Drill, Complete, Tie-in Costs; Nest 2: $12.0MM, Deep Southwest: $14.0MM.

Facing continental competition

Probably the most threatening competitive alternative to our Kakwa Nest natural gas is Utica and Marcellus natural gas because of its close proximity to the Chicago market. In the US$60/bbl boot chart, 7G's Montney Nest 2 has a clear supply cost advantage as do a few other Montney areas. Collectively, we may be able to satiate the market such that there is little motivation for the Utica and Marcellus producers to push into and compete in the Chicago market. However, the other boot diagram suggests that when the price is US$40/bbl, we have only a few cents per MMBtu advantage over our closest rivals, including other Canadian supplies, and the lowest cost Utica and Marcellus supply. We have a very high quality resource base and we believe that we are among the leaders in innovation. Therefore, we are likely on track to be able to capture, with prudent management of experimental investments aimed at improving well economics, the most value from our resource. As others optimize their development methods, there is a strong probability that the bars closest to the toe of the boot will become less differentiated. No matter what quality or technology advantages we and other northwest Alberta and northeast British Columbia developers may possess at low prices, the transportation costs related to the long distance from the market becomes the largest portion of our cost, and enables an advantage for supplies closer to the market.

In the final analysis, as the market sorts through various supplies of natural gas, we may find ourselves among a few profitable suppliers, but with little margin for superior returns unless we can find new ways to add value to our product. These observations point to the need to continue to innovate and to seek operating efficiencies in order to reduce our breakeven price so that we can maintain a superior operating margin. They also suggest that, as we consider marketing our growth potential, we should look for ways to expand the market away from the grossly oversupplied regions that are nearer to our competitors in Ohio, Pennsylvania and Texas.

Midstream processor service models – help or hinder

We support the continued renaissance in Canadian midstream service business models. Traditional midstream service models may significantly impair the competitiveness of Canadian natural gas projects when those producers enter into longer-term service agreements with midstream natural gas processors and/or shippers. Two experiences highlighted to me the need to reconsider the midstream service model as it is currently presented to Canadian producers.

First, I spent the better part of a day with an industry analyst. She's really a commodity price expert that I hold in very high regard for her insights upon the macroeconomic environment for the oil and natural gas industry. She indicated to me that market circumstances strongly favour vertically integrated companies. This left her to speculate that, if the present market prevails for a few more months, we should expect to see a wave of industry consolidation by the integrated companies – which own and operate their assets from the reservoir to the commodity markets. Some of the vertically integrated companies have better access to capital, the desire to own and control large, high-quality assets and have the financial and international operating ability to back the huge infrastructure investments that would be required to open up new markets in power generation, petrochemical manufacturing and Liquefied Natural Gas (LNG) exports off Canada's West Coast.

My second experience has come via a wave of distressed businesses. In the past few months, as oil prices have collapsed, we have been invited to make proposals to acquire some of the smaller liquids-rich natural gas projects, and even a few larger ones. In most cases, the assets are offered for sale in a distressed economic situation. In most of the cases that we have reviewed, the operators have contracted aspects of their field gathering and processing to midstream service providers. In the highly competitive, over-supplied market environment, where just a few cents per MMBtu determine whether a project is profitable or unprofitable, developable or not developable, able to attract capital or not able to attract capital, developers cannot afford some of the fees and conditions that we believe often go along with the use of midstream service providers. The table on the following page illustrates common elements of the Canadian midstream service model that can put the upstream operator at a disadvantage relative to a vertically integrated company that owns its own midstream and transportation assets.

It is important to note that this list does not apply to all midstream arrangements. In fact, it is possible that the entire list applies to none, but multiple elements of the list are common. 7G's reaction to the observations in the following table has been to establish an expert midstream group within the Company. We have supplemented the upstream and marketing expertise of Senior Vice President Marketing, Merle Spence with two former midstream/petrochemical executives, including, as recently announced, Charlotte Raggett, our Vice President Midstream Business Development, and a senior marketing expert. Our team has developed a proposed midstream service model that, if and when it gets take-up by the existing midstream business, will combine the strengths of credit ratings, balance sheets and access to vast amounts of low-cost capital of the healthiest midstreamers with highest quality upstream resources.

Many recently announced energy infrastructure arrangements are already departing from the traditional model, providing a greater ability for the upstream developer to adapt to market circumstances and access new markets more effectively. The new model provides a more sustainable economic balance of the risk/reward and value equation, giving all participants more financial resilience to endure the increasing competitive forces faced by Canada's natural gas sector, and is a better fit with 7G's integrated development plans.

The traditional midstream model historically served a very valuable purpose. It enabled very small explorers and producers to secure midstream expertise and infrastructure that their projects were too small or geographically dispersed to support. With the shale gas revolution, though, many projects are large enough to support their own gathering and processing infrastructure. Many, on their own, or in cooperation with just a few others, can support major transcontinental shipping and marketing initiatives. The Alliance Pipeline and Aux Sable processing facilities are a previous example of a producer-driven market expansion project.

Well financed and very large developers are faced with the option of vertically integrating to achieve the advantages described in the "vertically integrated" column below. A hybrid model might provide essentially all of the advantages of being vertically integrated to one or more major anchor tenant developers, while a midstream partner could provide a share of the capacity to developers desirous of small amounts of capacity. Financing of the anchor tenant's share could be through the midstream, or on a rent-to-own basis, or through direct financing.

For resource plays, such as very large tight-gas developments, in the final analysis, the value that underpins the infrastructure investment is the upstream asset – the oil and natural gas reserves. The nature of upstream assets has changed. Risks associated with the infill development of a very large, delineated resource are much lower than the risks associated with the historic oil and gas exploration and production business. For large projects, there is a compelling argument for a much lower cost of capital for financing or infrastructure developments that support one, or a few, very large, well-advanced projects.

An upstream producer's view of the Canadian midstream/downstream business model

Developer's value consideration	Vertically integrated	Canadian midstream model
What is the nominal cost of capital to producer?	Varies – but single digit interest rates have been achieved by developers with strong balance sheets and strong value propositions.	>9% interest on actual capital cost. Some interest rates may appear lower because higher than either actual or market capital cost is ascribed
How is risk managed? Who benefits from capital efficiencies that are gained?	Owner optimizes facility engineering and construction, taking reasonable risks to minimize cost. Upsides from excess capacity and debottlenecking are captured for the owner's benefit.	Midstreamer designs conservatively, over-estimates and over-pays to ensure plant capacity and schedule targets are met. Fees on design rate cover midstreamer's capital plus interest. Excess processing capacity goes to midstreamer to contract to third parties.
What product specifications are used at delivery points?	The specifications are optimized along the system to maximize value and minimize cost, and can change as suits the owner.	Specifications are often set to over-process in the field to eliminate any cost/risk to midstreamer and/or penalize producer for off-specification product. Product quality is physically downgraded by mixing during shipping requiring reprocessing. Extra or unnecessary field processing is at developer's expense.
What happens when producer desires a change in delivered volumes?	System is expeditiously adjusted to maximize value. Third party volumes may be processed to add revenue where excess capacity is available.	Expansions typically take 1 to 4 years. Producer often pays take-or-pay penalty on reduction of deliveries. Midstreamer deploys extra capacity for its own benefit. Producer often cannot assign partial contract to a third party.
Financial security	Balance sheet asset. Third party financial institutions have access to all of developer's assets.	Letter of credit, drag on credit capacity of producer, possibly land dedication also. Third party backers for large projects have indirect access to developer's resources, direct access to midstreamer's assets.
Customer service	Owner is a customer.	Service marketing and operations departments are often silos. Midstreamer is advantaged to minimize cost which is reflected in service.
Contribution to industry reputation/ social license	Fully owned, fully aligned. Part of community engagement by developer.	Focus most often on provincial or national scale. Regional engagement can be lost.
Ability to capture premium for founding sponsorship	Inherently captured.	All to midstreamer.

2. Challenges and opportunities to expand the market for our products – turning a red ocean blue

A management textbook that I have found to be very useful is *Blue Ocean Strategy*, by Renée Mauborgne and W. Chan Kim, published by Harvard Business Review in 2005. As the authors' website describes, the behaviour that they define as blue ocean strategy is "the simultaneous pursuit of differentiation and low cost to open up a new market space and create new demand." They contrast Blue Ocean Strategy with the more common Red Ocean Strategy, which involves going head-to-head with competitors in the same markets, using, more or less, the same strategies to, almost hopelessly, seek differentiating margins. The founders of the Alliance Pipeline and the Aux Sable fractionation plant in Chicago had what I would interpret to be a Blue Ocean strategy – build a special pipeline to keep liquids in natural gas that normal pipelines would require removing, ship the liquids-rich natural gas to a point near the market and separate the natural gas into products adjacent to the markets. In the broader sense, perhaps an extension of the concept, our use of specially designed plants to deliver into the Alliance pipeline is a Blue Ocean Strategy. We use Super Pads that have the capacity to accommodate a large number of wells, perhaps more than 50, which are drilled and added to the Super Pad facility over time. The Super Pad reduces several common problems:

- It provides lean natural gas that can be used for gas lift to effectively blow the inflowing liquids up the well to the surface;
- It enables removal of water that is naturally produced with the natural gas so that the tendency for the gathering system to become plugged with hydrates – a special type of ice formed from methane and water – is reduced;
- It prevents liquid slugs and facilitates a more effective flow of liquids and gases to central processing plants, achieving improved throughput efficiency of the central plants and reduced safety and operating capacity reduction risks; and
- It enables the control, over a broad range, of the downhole producing pressure of natural gas wells, which facilitates a process known as "slowback" a restricted flow rate that seems to increase condensate recovery.

Driving for innovation and efficiency

There are fundamentally two ways to compete:

- Do the same things as competitors but in a more effective and efficient way; and
- Innovate to find and do different things than competitors in broadly the same business.

The boundaries between these two types of activity are often blurred and stopping to classify is probably not as good of a use of time as continuing to drive for both efficiency and innovation. I think organizations are most effective when they have champions for both methods of competing. We compete both ways. We have two champions. We recruited our President and Chief Operating Officer, Marty Proctor, partly because he is very proficient in operational effectiveness, while I naturally focus on innovation. Under Marty's leadership, our costs have dropped and our safety incident frequency has dropped. Our activity level climbed at first, then subsided as we are now getting more done with less wells. Meanwhile, my focus has been to encourage the team to try new well and facility designs, and their success has contributed to our success. Marty has a more balanced ability in both functions than I have. But I think, as a team, we are better than two of either of us would be.

Pursuing new, blue markets

We are looking to find new markets for our natural gas to add to our existing liquids-rich natural gas market in Chicago and new markets for our natural gas liquids to add to our Edmonton-centred Alberta markets. These are red ocean markets, where the aggressive competition by competitors with similar strategies brings to mind bloody waters of a shark feeding frenzy. We can and we are competing in the red oceans of these markets. But Blue Ocean Strategy has me convinced that new markets, markets where our very large, very high-quality resource is essentially required to underpin major investments, can offer us growth potential where we can achieve differentiated netbacks. Here are some of things that we are looking at:

Short- to medium-term possibilities could include:

- Manufacturing petrochemical products from our resources, possibly with participation in an Alberta Government incentive program;
- Given that the Alberta government is planning to phase out coal-fired electricity generation, creating a market that is highly efficient and miserly as to greenhouse gas emissions through the development of natural gas combined cycle electrical power generation; and
- LNG and/or Liquefied Petroleum Gas (LPG) export from North America's West Coast, where the relatively short distances to northern Asia and the cooler temperatures present the prospect of creating a supply at the toe of the supply cost boot for the Asian market, primarily China, Japan, Korea, India and Malaysia. This would require the development of a liquids-rich natural gas pipeline, and fractionation and liquefaction facilities on the West Coast.

Longer term possibilities could include any of the above plus providing solvents for the recovery of heavy oil and oil sands. I have long been very positive about the prospects of solvent-based or solvent-augmented recovery of heavy oil. With the greenhouse gas emission program that the Alberta Government recently announced, I think there is increased motivation for heavier oil producers to look at the combined enhanced recovery and in-situ de-asphalting potential of NGL solvents directly or as an additive to steam.

How do we think that we can get this market expansion initiative done? We have started to assemble industry-leading expertise internally and we will also entertain very synergistic relationships with partners. In either case, we will stick to strategies that I have found essential to success in the four start-ups that I have founded in my career. Before 7G, there was:

- Passage Energy – heavy oil by cold production and waterflood;
- Krang Energy – heavy oil by cold production and horizontal well primary production, marginal natural gas production including well designs for dewatering, and light oil waterflood; and
- North American Oil Sands – oil sands via modularized steam-assisted gravity drainage (SAGD).

In each company, success was built on four strategies that I stick to:

1. Find a market niche – something that can be done and that most others are not focused on. My three previous companies all focused on tackling recovery risk, not discovery risk, which was where most oil and natural gas companies and most sector investors were focused during the lives of those three companies. It is worth noting that 7G's well and facility designs are an extension of reducing recovery risk and cost. As we started 7G, the prevalent trend was to drill short laterals and use central plants for processing. We were among the first companies to focus on liquids-rich natural gas and we did it at a time when industry pioneers were focused on high grading to the highest quality lean natural gas resources.

2. Get the best expertise. Companies are built on ideas and know-how. People own that. Companies do not. I was at an integrated major oil company in the 1980s when the president called a staff meeting and told us that the days when an oil company hired a university graduate and essentially promised him or her a job for life were over. He said companies would focus on employing the best available skills that they required at that time. Going forward, he said that company intended to hire, train and release staff as the corporate need dictated. That was a trend among the big companies then, but they failed to consider that loyalty is a tide that ebbs and flows. Today's workforce is highly mobile. Big companies are excellent training grounds, little companies offer an exciting, stimulating work environment with an opportunity to share in financial success. All of my companies have included resumes from among the industry's leaders in their respective fields.

3. Diversify to increase risk tolerance with respect to key risks. At Passage, we had four core properties using two recovery technologies, in two provincial jurisdictions. At Krang, despite being tiny, we had three business units focused on three areas of enhanced recovery: heavy oil by cold production and horizontal well primary production, marginal natural gas production including well designs for dewatering, and light oil waterflood. At North American Oil Sands, we had several different SAGD development areas. We reduced the risk associated with building permanent facilities over reservoirs that might prove to be sub-optimal by designing the plant to be modular and easily moved. At 7G, our liquids-rich natural gas simultaneously provides condensate, natural gas liquids and natural gas. We have multiple lands, multiple reservoir zones and unique facility designs to produce all products effectively.

4. Keep control of your products and your operations until you get a fungible product to an open market. Most of Passage's heavy oil could be trucked to multiple receiving points depending on which receiver was offering the best value. At Krang, the heavy oil situation was the same, but we also had a couple of dozen natural gas wells tied into a variety of gathering systems with a preference for midstreamers providing services to multiple customers, rather than competitor-owned gathering and processing. At North American, we planned an upgrader that would make a fungible synthetic crude product. These companies did not have partners, except North American, where eventually the partner vended its interest into the company for shares.

Capturing value throughout the chain, seeking vision alignment with potential partners

Our most pressing challenge may be breaking into new markets with no tolerance for inflexibility or excessive profit taking or any inefficiency by others in the value chain. In the case of LNG, we need to win the competition with the vertically integrated companies that intend to get their own natural gas to the Pacific market. We and our value chain partners must be efficient, nimble and aligned with a focus on generating superior returns from our investments throughout the value chain. We must present the Asian market with the lowest cost incremental supply of LNG and LPG, which is the refined derivatives of natural gas liquids. Partners offer many advantages, such as less capital required, access to the partner's specialized expertise and the partner's market network. In the final analysis though, partners need to bring clear value because the list of risks and burdens that they bring is at least as long as the list of assets. We are actively looking for partners willing to align with us in this kind of a vision. Our goal is to create a vertical alliance that has the advantages of a vertically integrated company and the nimbleness of a highly focused, early stage, sector leader through every link of the value chain.

Our very large resource base and the quality of our large inventory allows us to take on risks associated with the earliest stages of planning for enhanced market projects. We don't want to dedicate all of our resources to a single market. Diversification reduces overall risk. On the other hand, the more parties contributing to a vision the harder it is to accomplish goals in a reasonable time. Further, we think that it is unlikely that, when it comes to liquids-rich natural gas, we will find a prospective upstream partner with anywhere near the asset size and quality combination that we have. Thus, bringing in an upstream partner at a conceptual planning and feasibility stage is likely counter-productive. Even though working quickly alone with downstream and midstream partners will be our preference, we still want a portfolio of markets. Therefore, it is likely that in some cases we will have to source natural gas currently owned by others once the commercial plan is in place. We can do this through mergers and acquisitions or through partnerships, whichever serves our shareholders best. One principle is clear though, we would need a superior arrangement to take the initiative and the up-front risks.

So the foregoing articulates our vision for the simultaneous pursuit of differentiation and low cost supply that can open up new market space and create new demand. As we pursue Blue Oceans, we intend to continue to compete to win and to grow in existing markets, just as we have done to date.

3. 7G's resources in the context of the capacity of northwest Alberta and northeast British Columbia as a market supply region

As the break-even price boot diagrams that we have presented show, at least part of our resource is very high quality. There is also a lot of it. Proved plus Probable Reserve estimates are limited by the market that the evaluator believes to be reasonably captured over the next ten years. The category Best Estimate Contingent resources is used to describe, among other contingencies, resources that meet all the criteria to be Proved plus Probable reserves, but the owner has insufficient market access arranged within the forthcoming ten-year window. We have Proved plus Probable Reserves that reflect our contracted market access for ten years and a similar volume of Best Estimate Contingent Resources. There is much remaining to do before we have drilled and produced enough wells throughout our land base such that our evaluators can confidently classify the portions of our land base into the Reserves or Contingent Resources categories.

This situation creates a classic chicken-and-egg problem. We have to have the market in order to get the classification Reserves and we have to have the Reserves in order to provide stakeholders with confidence that we will be able to support new market access projects that often are financed on a lifespan of 15 years, and perhaps as long as 25 or 30 years. Our initial public offering prospectus, published in October 2014, showed that we have future development areas that, if developed today, would have a higher break-even price than the Nest area where our capital is now focused. If, when we can devote capital to their commercialization, we find that they will not competitively fill any infrastructure that we plan to develop, we will need to arrange for other supplies of natural gas, developed through commercial arrangements, to fill that infrastructure. In any case, we would expect to greatly advance commercialization work on our lands outside of the Nest so that we have a better understanding of our own resources well in advance of making major commitments on market access infrastructure.

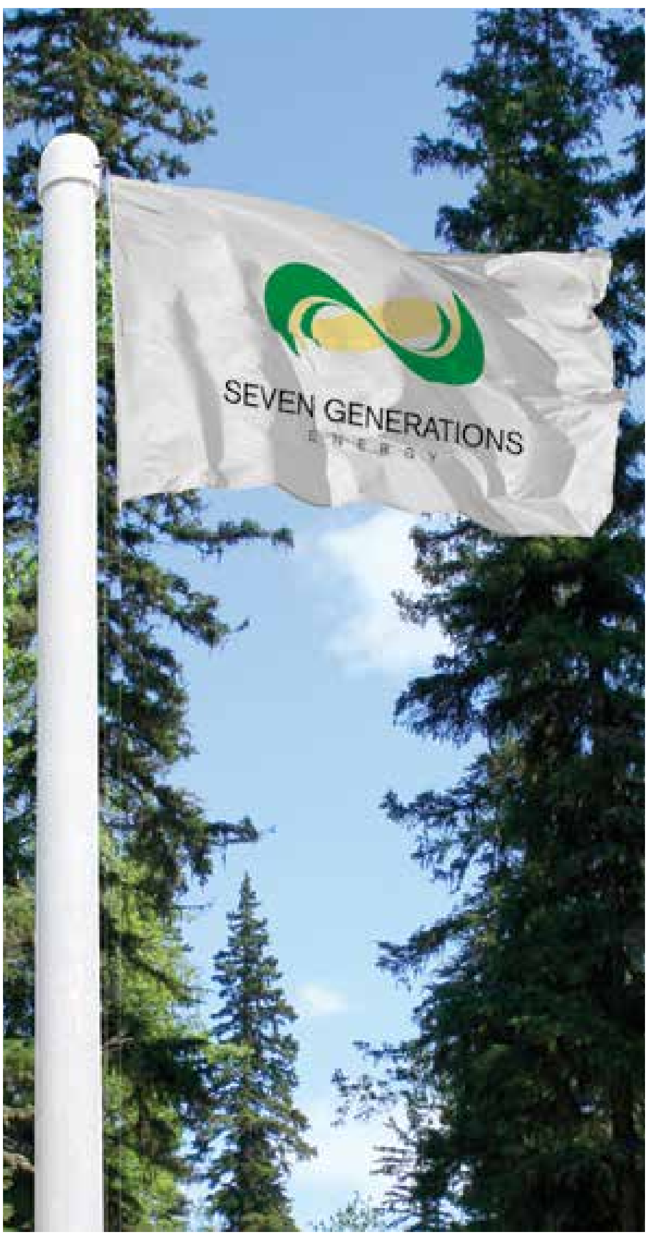
The resource potential in northwest Alberta and northeast British Columbia represents decades of supply. Therefore, we would expect markets to be over supplied for years to come. Canada's National Energy Board reports that the Montney Formation, which underlies a land mass roughly the size of Nova Scotia and New Brunswick combined, holds about 449 trillion cubic feet (Tcf) of marketable natural gas, which represents 140 years of supply at Canada's 2013 consumption rate of 3.2 Tcf per year. The Alberta Energy Regulator estimates that Alberta has an endowment of 3,424 Tcf of natural gas in its shale and siltstone reservoirs. Not all of that is economic, but it is evident that Western Canada has sufficient large resources to underpin market expansion projects: Red Ocean or Blue Ocean.

4. Evolving expectations for social license in our operating area

A First Nations advisor with a previous company told me a story that strongly influenced my business philosophy. She said that when Europeans first sailed up the St. Lawrence River they encountered the highly organized Iroquois society. Although the Iroquois did not have a written language, they had passed down for many generations a constitution that, among other provisions, required that decisions be made to the benefit of seven generations into the future. In 1988, the United Nations' Brundtland Commission published Our Common Future. It defined the concept of sustainable development, which is development that meets the needs of the present generation without compromising the ability of future generations to meet their own needs. Essentially the United Nations came to the same code of human conduct with respect to the environment that the Iroquois honoured as much as a millennium earlier. I asked my friend's permission to use Seven Generations as the name of my next company. Our name is meant to honour that concept and the original North Americans who founded it.

Our Level 1 Policy statement, or Code of Conduct, describes our mission: to differentiate in the service of our stakeholders and our values, the need to act in a way that honours our name and our Level 1 Policy. Together this mission and these values figuratively form a sturdy flag pole from which the flag of Seven Generations Energy's vision flies.

We recognize that the business environment for natural gas resource developers is rapidly evolving. Therefore it only makes sense that we adopt the vision that we must be nimble, cognizant of future possibilities, preserving of options, yet moving decisively and quickly to capture benefits for all of our stakeholders.



Our stakeholders expect us to act in harmony with the biophysical environment, preserving its capacity to recover as various phases of our operations mature and wind down. They also trust us with Alberta's resources. They want us to bring opportunity and prosperity to their communities, to the First Nations communities with traditional rights in the areas where we work, to our suppliers, our partners and customers, our contractors, our employees and our shareholders. They want us to obey laws and regulations. They want us to work with government and regulators to find ways to change the regulatory environment to make our industry more effective in serving stakeholders.

I believe the days of comprehensive regulation and attentive regulatory oversight of industry activity are near an end. Regulators don't have and can't afford the staff to write and enforce regulations that anticipate every responsible course of action for activity. Instead, I believe we will see a trend to higher level regulation, with strong license for those who are responsible to their stakeholders, largely a list similar to those listed in our Level 1 Policy. Others who prove themselves in need of direction will face cumbersome and slow bureaucratic processes.

In service to the government, our company loaned my services, under appropriate confidentiality obligations, to the Royalty Review Panel as a member of the Natural Gas Expert Group. Meanwhile our Chief Financial Officer Chris Law conducted an extensive information campaign providing 7G's views on royalties to our employees, the Grande Prairie community as well as our vendors and contractors, encouraging them to participate in the Panel's website set up to encourage public contribution to the dialogue. We invite regulators and government officials on tours, generally several times a year, so that they can learn about tight, deep-basin, over-pressured mixed hydrocarbon resource plays. The first-hand knowledge they gain will help contribute to the development of policy that might lead to our industry better serving the public. We have provided engineering and geology courses for regulator staff, explaining basic differences between conventional reservoirs and unconventional reservoirs, such as the Montney.

We work hard to get stakeholder input on our plans and to communicate them broadly to our stakeholders. We work hard to engage our stakeholders who want to actively participate in the Kakwa River Project. We take guidance on environmental protection from our name and our Level 1 Policy and we have undertaken initiatives that far exceed applicable regulations, outlined on the following page.

Fresh water conservation

We have studied and compared regional water needs for hydraulic fracturing and have compared these water needs to the carrying capacity of the local surface water drainage system. As a result, we have derived general guidelines for our own surface water use. Our findings have been shared with a public body concerned with water resource protection in which we actively participate. In addition, we are examining and testing the geological column in search of deep aquifers that may meet our needs as both a source of water and a safe zone to dispose of produced water. We are also examining water recycling, from three points of attack: water recycling logistics, the impact of various aspects of water quality on well performance and water recycling technologies.

Habitat conservation

We are pushing the length or our horizontal laterals and the lateral distance of the vertical portion of our wells. Our wells are reaching further and further from our Super Pads to tap more reservoir and cause less surface land disturbance. Pushing both of these limits with our drilling and completions designs has enabled us to access about 2,500 acres of reservoir using a well pad of about 20 acres in size, which means our pads cover less than one percent of the surface covering the reservoir we harvest. Looking ahead, we hope to further extend the drained area relative to the size of the disturbed area, as we advance well construction technologies. This, we believe, will enable us to develop and operate without extirpating key species. Wildlife are left to thrive in the undisturbed forest between our operations, and to quickly and spontaneously repopulate our development areas as we withdraw, first to a relatively quiet production operation and then, ultimately, to abandonment and reclamation.

Greenhouse gas emissions

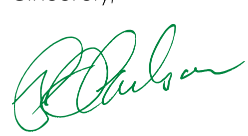
We have modern natural gas production facilities that use air pressurized pneumatic controls, not methane gas. We are working with an environmental compromise, using inert nitrogen foam as a fracture fluid, which requires preliminary flaring of natural gas from the completed well to remove the nitrogen from early flow back natural gas from the reservoir. Alternatively, we also can use predominantly water as the fracturing fluid, which uses six times as much water, but results in little to no flaring. We are working to find an improved well completions method that provides both benefits, and neither compromise.

Seismic activity

We can only produce the Montney formation at commercial rates if we hydraulic fracture the rock in the reservoir. When we hydraulic fracture we are breaking a small interval of the Earth's crust. In some cases that interval of the Earth's crust is still feeling some of the force that it was exposed to more than 50 million years ago when the Pacific tectonic plate slowly slid under the North American plate causing the rippling and tearing – the natural faulting and fracturing – that built and shaped the Rocky Mountains. When we break the Montney formation we can allow the Earth to release some of that force. When the Earth's crust trembles from breaking the Montney formation directly from the hydraulic fracture, or directly plus the indirect effects of the relieving natural stress, we expect to cause seismic activity. Seismic activity simply means shaking of the Earth. Many human activities, such as road building, hydro-electric dam and large project construction and passing trains, shake the Earth. When we discuss this matter with our stakeholders, we find they are almost exclusively concerned with seismic activity so severe that it leads to damage to property or the biophysical environment. We have not experienced, nor do we believe that our project will cause, that kind of seismic activity. However, to be fully informed on the potential impacts, we have voluntarily installed an array of geophones that we are monitoring for seismic activity from our operations.

While our list of things to do that differentiate us in the eyes of our stakeholders, things above and beyond mere compliance, continues to grow, the demands of our Level 1 Policy Statement are on the minds of all of our employees in the decisions that we make. As I close, I thank those stakeholders we see most often, our employees, contractors, suppliers, partners, our community members and shareholders, for all their contributions in completing a very successful first year as a public company. The year was crowned with additional success by a deep honour bestowed on Seven Generations. The Chamber of Commerce in Grande Prairie, the home of our operating headquarters, honoured us with the title Business Citizen of the Year 2016. We are privileged to call Grande Prairie home and tag ourselves Grande Prairie's Energy Company.

Sincerely,



Pat Carlson, P.Eng.
CEO

March 2016

CODE OF CONDUCT

We believe that companies have only the rights given to them by society. While people have a natural entitlement to basic rights, corporations are an instrument created by society to provide its needs and ought to have no expectation of basic entitlements other than equitable rights with other corporations, including those wholly owned by a person.

We recognize that rights, sufficient to build and operate an energy project, can be granted and taken away by society. Over the longer term, companies can only expect to thrive if they serve the legitimate needs of society in which they exist. To thrive, companies must differentiate, rise above the pack, standout as being among the best with all of their stakeholders. At Seven Generations Energy Ltd., we acknowledge this granted entitlement and accept from our stakeholders a duty to thrive and an understanding of the need to differentiate.

Specifically, in acceptance of this challenge to differentiate with all stakeholders, we acknowledge:

- The **need of society** for us to conduct our business in a way that protects the natural beauty of the environment and preserves the capacity of the earth to meet the needs of present and future generations;
- The **need of Canada and Alberta** for us to obey all regulations and to proactively assist with the formulation of new policy that enables our company and our industry to better serve society;
- The **need of the communities** where we operate to be engaged in the planning of our projects and to participate in the benefits arising from them as they are built and operated;
- The **need of our business partners and infrastructure customers** to be treated fairly and attentively;
- The **need of our suppliers and service providers** to be treated fairly and paid promptly for equipment and services provided to us and to receive feedback from us that can help them to be competitive and thrive in their businesses;
- The **need of our employees** to be compensated fairly and provided a safe, healthy and happy work environment including a healthy work life – outside life balance; and
- The **need of our shareholders and capital providers** to have their investment managed responsibly and ethically and to earn strong returns.

We see ourselves as being in the service business, serving the needs of our stakeholders. We seek satisfaction for all stakeholders. Differentiation is imperative. We support an open and competitive business environment, recognizing in the competitive world that we envision, only those who best serve their stakeholders can expect the support required to survive for the longer term.

PRESIDENT'S MESSAGE

Marty Proctor,
President & Chief Operating Officer

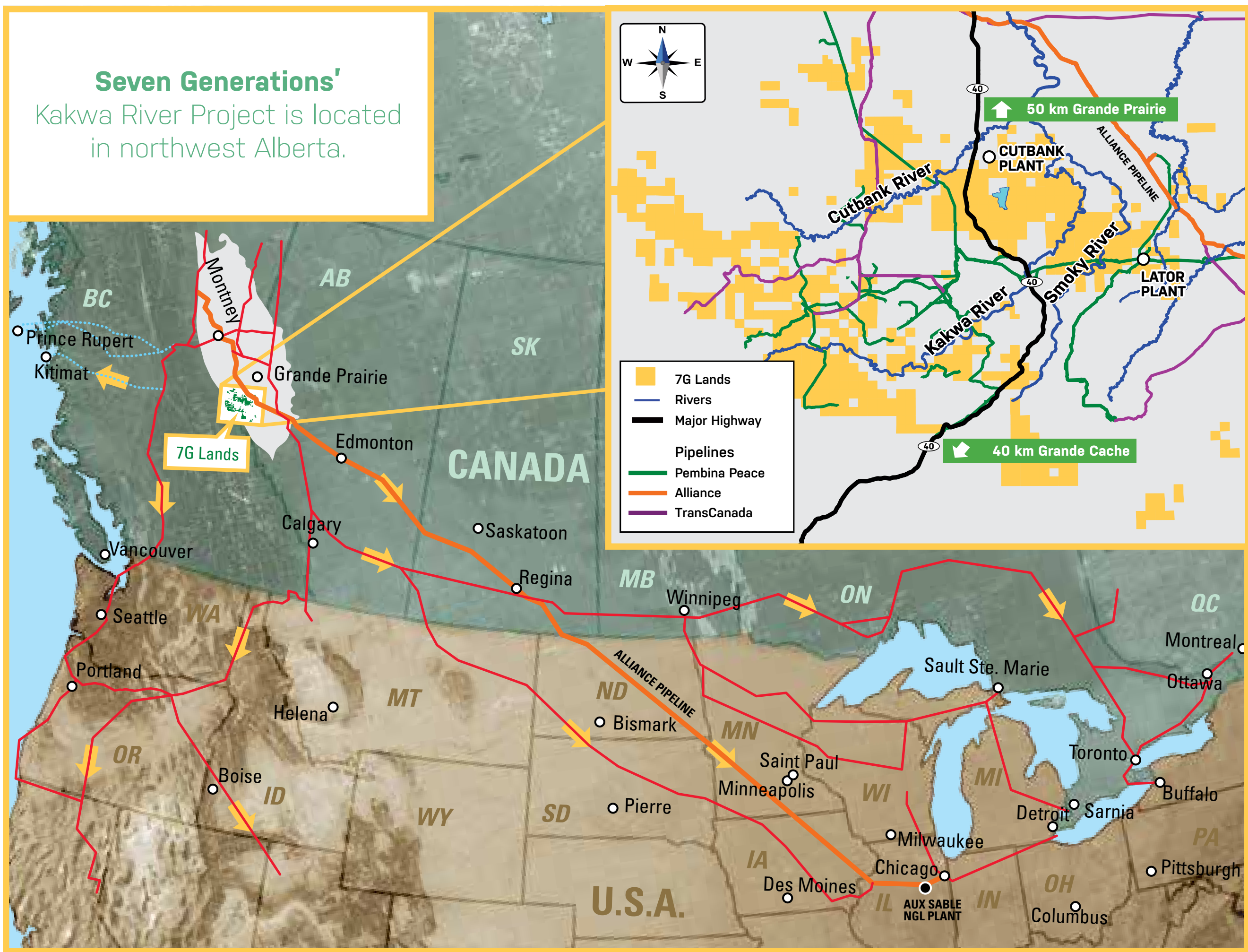
In our first full calendar year as a public company, we nearly doubled production, drilled long wells faster, improved well completion efficiency, lowered costs and built significant natural gas processing facilities. And while we grew production and reserves, we maintained our balance sheet strength. Despite a 43 percent year-over-year drop in commodity prices, 2015 funds from operations remained robust at $415 million, up 26 percent compared to 2014.

In 2015, we continued to deliver results that met or exceeded the production, operating cost, and capital investment targets that we communicated to the market. It is significant to note that we delivered the operational results while steadfastly adhering to our Level 1 Corporate Policy which defines how we deal with all stakeholders. Our Level 1 Policy commitment to staff and contractors includes providing a safe work environment. Our intense focus on creating a gold standard safety culture resulted in a Total Recordable Incident Frequency (TRIF) that was substantially better than the previous year and comparable to the performance achieved by the best run companies.

In the fall of 2014, we announced a $1.6 billion 2015 budget to deliver 55,000 to 60,000 barrels of oil equivalent per day (boe/d) of production. Then in February of 2015 we announced that we would reduce the capital investment, setting guidance between $1.3 billion and $1.35 billion, but we maintained the same production target. Capital investment in 2015 was $1.31 billion, which was at the low end of our guidance range, and production was 60,403 boe/d, which was slightly more than the upper end of the production guidance range. We understand that delivering what we promise, quarter-by-quarter and year-by-year, is critical to the success of our company.

An important target that we set several years ago was to deliver 250 million cubic feet per day (MMcf/d) of liquids-rich natural gas by December 1, 2015, which meets our Alliance Pipeline firm transportation commitment. We achieved this milestone by efficiently executing our 2015 program, which included drilling 82 and completing 58 Montney wells, expanding our gas processing capacity to at least 260 MMcf/d and commissioning a 25,000 barrel per day (bbl/d) stabilizer to process our condensate production.

In 2015, we drilled 82 wells with lateral sections averaging 2,713 meters 20 percent faster and 24 percent cheaper than in 2014. The cost per meter drilled has improved from $2,370 per metre in 2014 to about $1,800 per metre in 2015 with the fourth quarter of 2015 averaging about $1,550 per metre. As a result, the cost to drill a well moved from $6.6 million in 2014 to $5.0 million in 2015 and $4.1 million in the fourth quarter of 2015. We estimate that approximately 70 percent of our drilling cost reductions have been achieved through innovation and efficiency, for example reducing spud-to-rig-release days from 57 in the fourth quarter of 2014 to 36 in the fourth quarter of 2015. The remaining 30 percent of the drilling cost savings have resulted from suppliers and service providers reducing their charge rates, reflecting lower margins in the service and supply business and improved efficiencies on the service and supply side. We expect that the majority of the drilling cost savings that we have realized will be preserved as the industry recovers and returns to higher activity levels.



We completed a total of 58 wells in 2015, with an average of 29 stages per well, an average of 4,395 metric tonnes of sand per well, at an average cost of $6.8 million per well. During the fourth quarter we completed 13 wells with an average cost of $6.1 million per well, which, using fourth quarter drilling costs, would result in a construction cost of $10.2 million per well. Our completions costs were down about 26 percent in 2015, while we pumped significantly more sand per well than in 2014. However, we are not focused on headline well costs alone, instead we are committed to maximizing the value of our resource.

With this in mind, we continue to push the envelope on completions. For example, we tested proppant densities on three wells ranging from 2 tonnes to 6 tonnes per metre during the fourth quarter. We have also started to use slickwater for a portion of our completions, which eliminates nitrogen related flaring and reduces our carbon footprint. We will continue to compare the results to our standard nitrogen foam fracture completions as we work to optimize our completions technology. Our innovation and optimization focus, which included tests with larger hydraulic fractures spaced closer together than our previous standard design, along with our deliberate restraints on production rates, a technique known as slow-back, have improved our Kakwa well type curves – the core measure of well productivity. The combination of lower well costs and improved type curves generates better economics, which helps to offset the negative effect of low commodity prices.

Our facility engineering team had many significant accomplishments in 2015, completing major projects ahead of schedule and under budget, and advancing additional projects that are required to meet our future processing needs as our production continues to grow. Our Lator 2 natural gas processing plant came online in the fourth quarter, approximately six weeks ahead of schedule and 15 percent under budget, and it is demonstrating operational performance consistent with the design capacity. Our second nominal 250 MMcf/d gas processing plant, the Cutbank plant, is under construction and is on time and budget. We expect it to be processing incremental gas volumes in the second quarter of 2016. We are also constructing a 29 km, 24-inch diameter natural gas sales pipeline, including a 2.2 km section of pipe under the Cutbank River, which was directionally drilled at a steep angle about 80 metres below the riverbed, leaving the surface of the river valley untouched. This new pipeline connects our nearly complete Cutbank processing plant to the Alliance Pipeline for the delivery of liquids-rich natural gas to the Chicago area market. Building our own facilities means that we can complete these projects on our own timeline and budget, and ensures we have control over the processing capacity that supports our planned growth.

During the fourth quarter, production facilities were installed on 7G's seventh Super Pad, #6, where production began flowing at the end of January. Construction continued to progress on schedule and budget for 7G's eighth Super Pad, #4-14, which is expected to be commissioned in the first quarter of 2016. These eight Super Pads will bring our total field gathering and processing capacity to 400 MMcf/d of natural gas and 80,000 bbls/d of field condensate. The field-specific design of Super Pad production facilities enables raw gas dehydration and free liquid separation from the very rich natural gas produced at the wellhead. 7G Super Pads are designed and constructed to deliver high-pressure, produced natural gas a short distance back to the wells to facilitate artificial lift. With the high liquids content of our Montney natural gas, the wells tend to load up with liquids as the near-wellbore reservoir pressure declines. When our wells are initially completed, gas lift components are installed to prepare in advance for the time when the bottom-hole pressure is insufficient to lift liquids. Gas lift is an efficient artificial lift method that enables steady production of the field's high volume of condensate and natural gas liquids.

Full year 2015 production was 60,403 boe/d which was slightly above the high end of guidance, and liquids ratios have been consistently around 58 percent, with condensate averaging 35 percent of total corporate volumes. Fourth quarter production averaged 77,700 boe/d which was an approximate 75 percent increase over the fourth quarter of 2014. We continue to choke our wells, or use the slow-back production method, which helps maintain downhole pressures and improves our liquids recoveries while creating a shallower decline in our production profile. Our decline rate is approximately 30 to 35 percent, which is less than typical for resource plays that are produced at unconstrained rates. As a result, the number of wells required to maintain production is relatively low. Considering our strong capital efficiencies and moderate decline rates, we estimate that we could sustain a flat production profile by investing less than the cash flow we expect to generate. We are choosing to invest more than our anticipated cash flow into infrastructure and wells because we believe that the growth program we are executing will maximize the value of our Montney acreage and accelerate our path towards cash flow sustainability.

Our 2015 year-end reserves report continued to reflect our ability to convert resources to reserves to production. McDaniel & Associates Consultants Limited (McDaniel) has estimated that Seven Generations had 73 million barrels of oil equivalent (MMboe) of gross proved developed producing reserves at December 31, 2015, up 115 percent from 34 MMboe at the end of 2014. This

"Innovation is a strategic cornerstone at Seven Generations. We will continue to experiment with well construction techniques, modular facilities, and other innovative and creative methods to improve capital efficiencies and leadership as a low-cost supplier of liquids-rich natural gas for North American consumers."

is significant because it defines our capacity to generate cash flow from existing wells. Additionally, we saw our proved plus probable reserves increase by about 10 percent to about 860 MMboe as the independent evaluators recognize improved recovery from our lands. Within our core producing property called the Nest, we estimate, and McDaniel agrees, that there are more than 930 potential drilling opportunities in the Upper and Middle Montney formation with approximately 54 percent of these potential drilling locations having reserves attributed to them, and the remaining locations having contingent resources attributed to them. These locations represent an inventory of 12 to 18 years of drilling within the Nest. This longevity is based on our current drilling rates of 82 wells in 2015 and our plans to drill about 50 wells in 2016. We are also encouraged by the fact that our focus on technical innovation, operational efficiencies and asset quality are being acknowledged by McDaniel through a combination of decreased future development capital and increased technical reserve revisions. Estimated undiscounted future development costs were 33 percent lower at $4.1 billion for proved reserves and down 20 percent to $7.1 billion for proved plus probable reserves. A 31.5 MMboe increase in gross proved reserves, which was attributable to technical revisions, provides external confirmation that our innovation efforts are improving capital efficiencies and that the quality of the resource is exceeding expectations.

Outlook

Seven Generations plans a 2016 capital investment program of $900 million to $950 million that is focused on drilling, well completions and production facilities, investments that will help advance 7G towards generating positive free cash flow. At current commodity prices, we expect to operate five rigs through the remainder of 2016, down from the average of 10 rigs that we operated through most of 2015. This lower rig count reflects 7G's improved capital efficiencies and reduced capital investment in drilling due to lower commodity prices. 2016 production is expected to average 100,000 to 110,000 boe/d, representing an approximate 75 percent increase over 2015 average production of 60,403 boe/d. In 2016, 7G's liquids are expected to range between 55 and 60 percent of total production.

2016 capital investments are weighted towards the early months of 2016 with a focus on completing and commissioning the Cutbank plant, which is expected to take 7G's processing capacity at Kakwa from 260 MMcf/d to 510 MMcf/d of liquids-rich natural gas. Our seventh Super Pad was completed early this year. As the rest of 2016 unfolds, we plan to complete and tie-in about 67 wells, finish the construction of 7G's eighth and ninth Super Pads and related gathering pipelines and complete construction of major production facilities, including a second 25,000 bbl/d condensate stabilizer at the Karr facility.

In 2016, the Company has contracted firm transportation capacity on Alliance Pipeline that averages approximately 350 MMcf/d, and that Alliance capacity is scheduled to incrementally step up to 500 MMcf/d in late 2018. Owning and operating our gathering lines and processing facilities increases our operational flexibility. We constantly analyze our business plan and can adapt quickly as the investment environment changes. Having control of our infrastructure, and the excess processing capacity that the new Cutbank plant will provide, means that when there is a strengthening of commodity prices, we could choose to increase our pace of drilling and completions to grow more quickly. Conversely, if commodity prices deteriorate to a level at which developing our Nest 2 locations is no longer prudent, we would work with our marketing partner to subcontract our capacity on Alliance Pipeline.

In executing our 2016 program we will remain focused on safety, protecting the environment and serving our stakeholders. Innovation is a strategic cornerstone at Seven Generations, which means we will continue to experiment with well construction techniques, modular facilities, and other innovative and creative methods to improve capital efficiencies and leadership as a low-cost supplier of liquids-rich natural gas for North American consumers.

Sincerely,

Marty Proctor
President & Chief Operating Officer

March 2016

HIGHLIGHTS SUMMARY

FINANCIAL

- Funds from operations reached $415 million, up 26 percent compared to 2014, despite a 43 percent year-over-year drop in commodity prices;
- Capital investment of $1.31 billion was at the low end of 7G's 2015 guidance range of $1.30 billion to $1.35 billion; and
- Achieved netback after hedging of $23.72 per barrel of oil equivalent, which benefited from a $6.83 per boe increase from commodity price hedging.

OPERATIONAL

- Record production of 60,403 barrels of oil equivalent per day (boe/d), and up 94 percent from 2014 and slightly more than 7G's 2015 guidance range of 55,000 to 60,000 boe/d;
- Drilled 82 wells at an average cost of $5 million per well, down 24 percent compared to 2014;
- Completed 58 wells and an average cost of $6.8 million per well, down 26 percent, while the volume of sand proppant pumped into each well increased about 34 percent;
- A determined focus on innovation and optimization focus boosted well productive performance, larger hydraulic fractures spaced closer together, along with our deliberate restraints on production rates, a technique known as slowback, improved Kakwa well type curves – the fundamental to for measuring well productivity;
- Completed construction and commissioning six weeks early and about 15 percent under budget of Lator 2 natural gas processing plant, which added 200 million cubic feet per day (MMcf/d) of processing capacity. Lator complex capacity increased to 260 MMcf/d and operational performance demonstrating design capacity; and
- Commenced delivery under contract with Alliance Pipeline of liquids-rich natural gas to an effective pricing point at Chicago.

RESERVES – EVALUATED BY MCDANIEL AS AT DECEMBER 31, 2015

- Gross proved developed producing reserves were 73.3 MMboe, up 115 percent from 34.1 MMboe at December 31, 2014;
- Total gross proved reserves were 424 MMboe and gross proved plus probable reserves were 859 MMboe, representing an increase of 1 percent and 9 percent, respectively, when compared to 7G's December 31, 2014 total proved and proved plus probable reserves;
- Total undiscounted future development costs were estimated to be $4.1 billion for proved reserves, down 33 percent, and $7.1 billion for proved plus probable reserves, down 20 percent, compared to the end of 2014. Lower future development costs are the product of technical innovation, improving capital and operational efficiencies and enhanced productive performance from the Company's high quality Kakwa River Project asset; and
- Before tax net present value of future net revenue estimates, using a discount rate of 10 percent per annum, was $2.9 billion for gross proved reserves and $6.5 billion for gross proved plus probable reserves.

STRONG BALANCE SHEET

- Maintained a strong balance sheet despite a 43 percent decrease in commodity prices;
- Expanded existing senior secured credit facility, provided by a syndicate of ten financial institutions, by 30 percent, or $200 million, to $850 million;
- Raised US$425 million long term debt – 6.750 percent senior notes due 2023; and
- Added to the S&P/TSX Composite Index, the headline index for the Canadian equity markets, in June, 2015.

2015 FINANCIAL AND OPERATING RESULTS

Year ended December 31	2015	2014	% Change
OPERATIONAL			
Production			
Oil and condensate (bbls/d)	**21,204**	11,061	92
NGLs (bbls/d)	**14,341**	6,989	105
Natural gas (MMcf/d)	**149**	79	89
Oil equivalent (boe/d)	**60,403**	31,136	94
Liquids percent	**59%**	58%	2
Realized prices			
Oil and condensate ($/bbl)	**50.84**	85.34	(40)
NGLs ($/bbl)	**10.34**	24.10	(57)
Natural gas ($/Mcf)	**2.65**	4.50	(41)
Oil equivalent ($/boe)	**26.85**	47.06	(43)
Operating netback per boe ($) (1)			
Oil and natural gas revenue	**26.85**	47.06	(43)
Royalties	**(2.63)**	(4.57)	(42)
Operating expenses	**(4.59)**	(4.77)	(4)
Transportation expenses	**(2.74)**	(3.06)	(10)
Netback prior to hedging	**16.89**	34.66	(51)
Realized hedging gain (loss)	**6.83**	0.86	nm
Netback after hedging	**23.72**	35.52	(33)
General and administrative expenses per boe	**1.10**	1.78	(38)
Selected financial information			
Oil and natural gas revenue	**591,924**	534,833	11
Funds from operations (1)	**414,609**	327,933	26
Per share – diluted	**1.54**	1.46	5
Operating income (loss) (1)	**52,105**	119,521	(56)
Per share – diluted	**0.21**	0.53	(60)
Net income (loss)	**(187,296)**	144,200	(230)
Per share – diluted	**(0.75)**	0.64	(217)
Weighted average shares – diluted	**249,549**	224,717	11
Total capital investments	**1,308,973**	1,120,336	17
Available funding (1)	**1,118,143**	1,133,800	(1)
Net debt (1)	**1,250,857**	158,270	nm
Debt outstanding	**1,546,761**	813,880	90

(1) Operating netback, funds from operations, operating income, available funding and net debt are not defined under IFRS. See "Non-IFRS Financial Measures" in Management's Discussion and Analysis for the year ended December 31, 2015.

MANAGEMENT'S DISCUSSION AND ANALYSIS

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

ABOUT SEVEN GENERATIONS ENERGY LTD.

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

Highlights for The Fourth Quarter and Year Ended December 31, 2015

Financial Performance

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

Capital Investments

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

Transportation and Marketing

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

Risk Management

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

Reserves Update

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

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

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

(1) Proved developed producing plus proved developed non-producing reserves.

(2) Company gross reserve as determined by McDaniel, the Company's independent reserves evaluator.

(3) Before tax net present value using a 10% discount rate.

Outlook and 2016 Guidance

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

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

OPERATIONAL AND FINANCIAL HIGHLIGHTS

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

	Three months ended December 31			Year ended December 31		
($ thousands, except per share and volume data)	**2015**	2014	% Change	**2015**	2014	% Change
Production						
Condensate (bbls/d)	**25,572**	14,747	73	**21,204**	11,061	92
NGLs (bbls/d)	**19,236**	10,783	78	**14,341**	6,989	105
Liquids (bbls/d)	**44,808**	25,530	76	**35,545**	18,050	97
Natural gas (MMcf/d)	**197**	112	76	**149**	79	89
Total Production (boe/d)	**77,699**	44,178	76	**60,403**	31,136	94
Liquids ratio	**58%**	58%	0	**59%**	58%	2
Financial						
Operating income (loss) (1)	**(14,191)**	34,815	(141)	**52,105**	119,521	(56)
Per share – diluted	**(0.06)**	0.14	(143)	**0.21**	0.53	(60)
Revenue (2)	**245,914**	287,141	15	**676,709**	639,432	11
Net income (loss) for the period	**(28,922)**	68,628	(142)	**(187,296)**	144,200	(230)
Per share – diluted	**(0.11)**	0.28	(139)	**(0.75)**	0.64	(217)
Funds from operations (1)	**106,031**	101,503	4	**414,609**	327,933	26
Per share – diluted	**0.40**	0.41	(2)	**1.54**	1.46	5
Adjusted Working Capital	**306,143**	653,800	(53)	**306,143**	653,800	(53)
Weighted average shares – diluted	**252,896**	248,510	2	**249,549**	224,717	11
Total capital investments	**301,149**	370,320	(19)	**1,308,973**	1,110,916	18
Available funding (1)	**1,118,143**	1,133,800	(1)	**1,118,143**	1,133,800	(1)
Net debt (1)	**1,250,857**	158,270	nm	**1,250,857**	158,270	nm
Debt outstanding	**1,546,761**	813,880	90	**1,546,761**	813,880	90

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

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

Production

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

Operating Income (Loss)

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

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

Net Income (Loss)

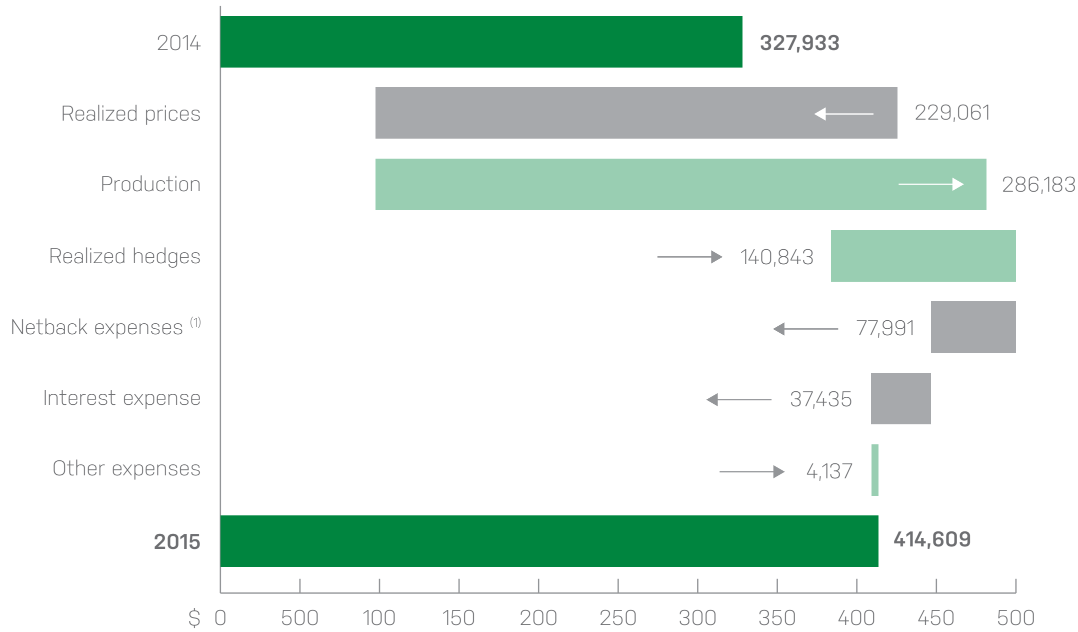
For the fourth quarter of 2015, the Company recognized an operating loss of $28.9 million compared to net income of $68.6 million for the same period in 2014. In addition to the items impacting operating income (loss) noted above, the decrease is due to higher unrealized foreign exchange losses on the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

Funds from Operations

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

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

Funds from Operations for the Year Ended December 31, 2015
$000s



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

Capital Investments

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

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

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

Available Funding

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

Operating Netback

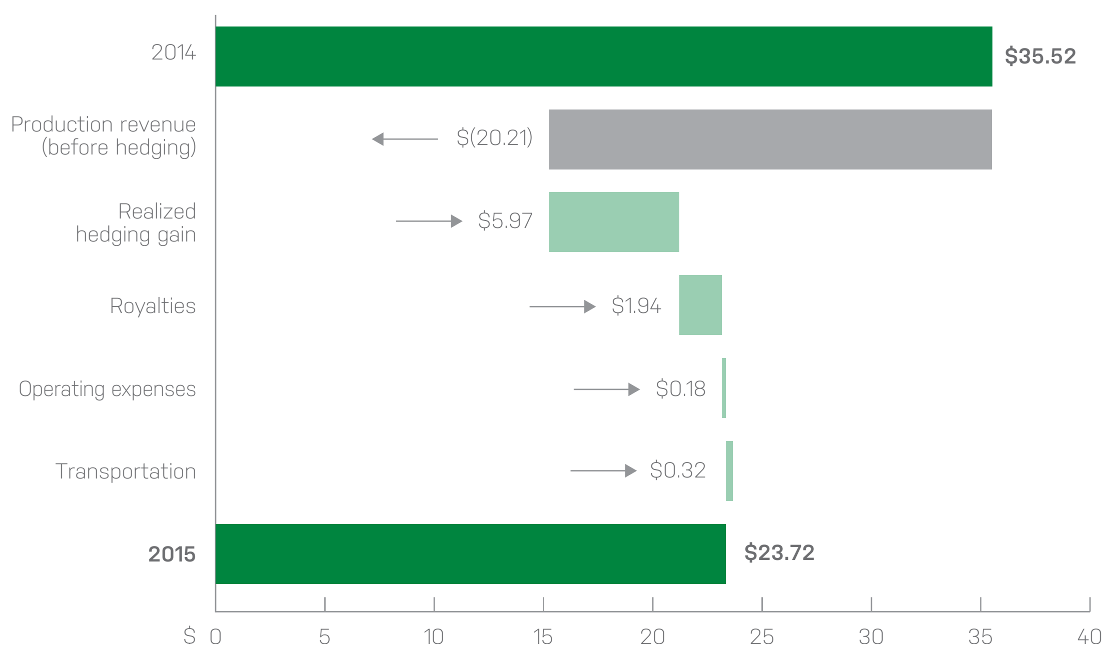
	Three months ended December 31			Year ended December 31		
	2015	2014	% Change	**2015**	2014	% Change
Sales	**24.97**	38.23	(35)	**26.85**	47.06	(43)
Realized hedging	**3.21**	5.45	(41)	**6.83**	0.86	nm
Royalties	**(1.70)**	(3.97)	(57)	**(2.63)**	(4.57)	(42)
Operating expenses	**(4.11)**	(4.67)	(12)	**(4.59)**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

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

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

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

Operating Netback for the Year Ended December 31, 2015
$/bbl



Selected Annual Financial Information

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

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

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

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

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

Daily Production

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

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

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

Well Information

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

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

Commodity Pricing

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

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

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

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

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

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

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

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

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

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

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

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

Liquids and Natural Gas Sales

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

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

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

Risk Management Contracts

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

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

(1) Represents actual cash settlements or receipts under the respective contracts.

(2) Represents the change in fair value of the contracts during the period.

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

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

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

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

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

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

Royalty Expense

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

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

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

Other Income

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

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

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

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

Operating Expenses

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

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

Transportation Expenses

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

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

General and Administrative Expenses

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

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

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

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

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

Depletion, Depreciation and Amortization

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

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

Stock Based Compensation

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

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

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

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

Finance Expense

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

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

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

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

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

Foreign Exchange Loss (Gain)

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

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

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

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

Gain on Disposition of Assets

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

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

Income Tax Expense

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

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

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

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

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

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

Capital Investments

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

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

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

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

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

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

Liquidity and Capital Resources

The capital structure of the Company is as follows:

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

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

(2) Market capitalization is calculated using the total common shares outstanding at December 31, 2015 multiplied by the closing share price of $13.48 at December 31, 2015 (closing share price of $17.50 at December 31, 2014).

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

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

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

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

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

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

Subsequent Event

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

Financial Instruments and Risk Management Contracts

Financial Instrument Classification and Measurement

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

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

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

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

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

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

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

Financial Assets and Financial Liabilities Subject to Offsetting

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

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

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

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

Credit Risk

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

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

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

Market Risk

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

(a) Commodity Price Risk

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

Risk Management Contracts

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

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

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

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

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

(b) Interest Rate Risk

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

(c) Foreign Currency Exchange Risk

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

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

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

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

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

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

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

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

Liquidity Risk

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

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

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

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

Contractual Obligations

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

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

(1) Balance represents US$1.1 billion principal converted to Canadian dollars at the closing exchange rate for the period end.

(2) Subject to completion of certain pipeline and facility upgrades by the counterparty transportation company.

(3) The Company is committed under operating leases for office premises.

(4) In November 2014, the Board of Directors approved a retention bonus plan for management and employees in aggregate of $6.0 million, payable over the two-year period starting November 5, 2014. Of this amount, $2.7 million is payable in 2016.

Off-balance Sheet Arrangements

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

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

Outstanding Share Data

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

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

Controls and Procedures

Disclosure Controls and Procedures

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

Internal Control over Financial Reporting

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

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

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

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

Critical Accounting Policies and Estimates

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

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

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

Risk Assessment

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

- Volatility in market prices and demand for oil, NGLs and natural gas and hedging activities related thereto;
- General economic, business and industry conditions;
- Variance of the Company's actual capital costs, operating costs and economic returns from those anticipated;
- The ability to find, develop or acquire additional reserves and the availability of the capital or financing necessary to do so on satisfactory terms;
- Risks related to the exploration, development and production of oil and natural gas reserves and resources;
- Negative public perception of oil sands development, oil and natural gas development and transportation, hydraulic fracturing and fossil fuels;
- Actions by governmental authorities, including changes in government regulation, royalties and taxation;
- The rescission, or amendment to the conditions of, groundwater licenses of the Company;
- Management of the Company's growth;
- The ability to successfully identify and make attractive acquisitions, joint ventures or investments, or successfully integrate future acquisitions or businesses;
- The availability, cost or shortage of rigs, equipment, raw materials, supplies or qualified personnel;
- Adoption or modification of climate change legislation by governments;

- The absence or loss of key employees;
- Uncertainty associated with estimates of oil, NGLs and natural gas reserves and resources and the variance of such estimates from actual future production;
- Dependence upon compressors, gathering lines, pipelines and other facilities, certain of which the Company does not control;
- The ability to satisfy obligations under the Company's firm commitment transportation arrangements;
- The uncertainties related to the Company's identified drilling locations;
- The high-risk nature of successfully stimulating well productivity and drilling for and producing oil, NGLs and natural gas;
- Operating hazards and uninsured risks;
- The possibility that the Company's drilling activities may encounter sour gas;
- Execution of the Company's business plan;
- Failure to acquire or develop replacement reserves;
- The concentration of the Company's assets in the Kakwa River Project area;
- Unforeseen title defects;
- Aboriginal claims;
- Failure to accurately estimate abandonment and reclamation costs;
- Development and exploratory drilling efforts and well operations may not be profitable or achieve the targeted return;
- Horizontal drilling and completion technique risks and failure of drilling results to meet expectations for reserves or production;
- Limited intellectual property protection for operating practices and dependence on employees and contractors;
- Third-party claims regarding the Company's right to use technology and equipment;
- Expiry of certain leases for the undeveloped leasehold acreage in the near future;
- Failure to realize the anticipated benefits of acquisitions or dispositions;
- Failure of properties acquired now or in the future to produce as projected and inability to determine reserve and resource potential, identify liabilities associated with acquired properties or obtain protection from sellers against such liabilities;
- Governmental regulations;
- Changes in the interpretation and enforcement of applicable laws and regulations;
- Environmental, health and safety requirements;
- Restrictions on drilling intended to protect certain species of wildlife;
- Potential conflicts of interests;
- Actual results differing materially from management estimates and assumptions;
- Seasonality of the Company's activities and the Canadian oil and gas industry;
- Weather related risks, fires and natural disasters;
- Alternatives to and changing demand for petroleum products;
- Extensive competition in the Company's industry;
- Changes in the Company's credit ratings;
- Third-party credit risk;

- Dependence upon a limited number of customers;
- Lower oil, NGLs and natural gas prices and higher costs;
- Terrorist attacks or armed conflict;
- Loss of information and computer systems;
- Inability to dispose of non-strategic assets on attractive terms;
- Security deposits may be required under provincial liability management programs;
- Reassessment by taxing authorities of the Company's prior transactions and filings;
- Variations in foreign exchange rates and interest rates;
- Third-party credit risk including risk associated with counterparties in risk management activities related to commodity prices and foreign exchange rates;
- Sufficiency of insurance policies;
- Potential of litigation;
- Variation in future calculations of non-IFRS measures;
- Sufficiency of internal controls;
- Third-party breach of agreements;
- Impact of expansion into new activities on risk exposure;
- Inability of the Company to respond quickly to competitive pressures; and
- Risks related to the common shares that are publicly traded and the senior notes and other indebtedness.

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

Changes in Accounting Policies

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

Future Accounting Policy Changes

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

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

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

Non-IFRS Financial Measures

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

Funds from Operations

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

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

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

Operating Income (Loss)

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

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

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

(1) Unrealized gains and losses on risk management contracts result from the fair market valuation of the hedge contracts as at December 31.

(2) Unrealized foreign exchange gains and losses result from the translation of the US$ denominated senior notes and cash and cash equivalents using period end exchange rates.

(3) Non-recurring gain resulting from disposition of assets.

Operating Netback

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

Available Funding

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

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

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

Net Debt

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

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

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

SELECTED QUARTERLY INFORMATION

($ thousands, except per share amounts, production rates and unit)	Q4 2015	Q3 2015	Q2 2015	Q1 2015	YTD 2015
FINANCIAL					
Total revenues	**178,478**	149,723	155,183	108,540	591,924
Realized hedging gain	**22,980**	35,262	41,683	50,655	150,580
Midstream revenue	**1,300**	-	-	-	1,300
Processing and third party income	**691**	467	294	385	1,837
Interest and other income	**879**	1,248	1,450	1,300	4,877
Royalties	**(12,127)**	(17,704)	(12,886)	(15,181)	(57,898)
Operating expenses	**(29,378)**	(26,819)	(23,537)	(21,454)	(101,188)
Transportation expenses	**(23,984)**	(13,493)	(9,893)	(12,966)	(60,336)
General and administrative	**(7,128)**	(5,450)	(5,136)	(6,629)	(24,343)
Interest expense	**(29,105)**	(28,211)	(24,946)	(17,973)	(100,235)
Foreign exchange loss	**3,456**	(98)	4,614	242	8,214
Other	**(31)**	(31)	(31)	(30)	(123)
Funds from operations (1)	**106,031**	94,894	126,795	86,889	414,609
Per share – diluted	**0.40**	0.35	0.47	0.32	1.54
Operating income (1)	**(14,191)**	13,813	28,485	23,998	52,105
Per share – diluted	**(0.06)**	(0.21)	0.11	0.09	(0.07)
Net loss	**(28,922)**	(53,726)	(21,950)	(82,698)	(187,296)
Per share – diluted	**(0.11)**	(0.21)	(0.09)	(0.34)	(0.75)
Capital investments:					
Land	**2,169**	1,930	259	780	5,138
Drilling and completions	**181,108**	145,626	222,164	264,879	813,777
Facilities and equipment	**114,153**	134,494	128,588	100,723	477,958
Other	**3,719**	3,064	3,299	2,018	12,100
Total capital investments (before dispositions)	**301,149**	285,114	354,310	368,400	1,308,973
Total assets	**3,758,982**	3,707,714	3,559,768	3,170,401	3,758,982
Available funding (1)	**1,118,143**	1,141,232	1,325,954	861,385	1,118,143
Net debt (1)	**1,250,857**	989,843	710,200	505,234	1,250,857
Debt outstanding	**1,546,761**	1,491,184	1,395,485	888,356	1,546,761
OPERATING					
Average daily production					
Oil and condensate (bbls/d)	**25,572**	22,606	20,702	15,810	21,204
NGLs (bbls/d)	**19,236**	14,094	11,914	12,042	14,341
Natural gas (MMcf/d)	**197**	143	130	125	149
Total (boe/d)	**77,699**	60,600	54,219	48,768	60,403
Realized prices					
Oil and condensate ($/bbl)	**46.72**	49.18	60.29	47.59	50.84
NGLs ($/bbl)	**12.35**	7.99	9.78	10.41	10.34
Natural gas ($/Mcf)	**2.57**	2.81	2.63	2.62	2.65
OPERATING NETBACK (1)					
Liquids and natural gas revenues	**24.97**	26.86	31.45	24.73	26.85
Realized hedging gain	**3.21**	6.32	8.45	11.54	6.83
Royalties	**(1.70)**	(3.18)	(2.61)	(3.46)	(2.63)
Operating expenses	**(4.11)**	(4.81)	(4.77)	(4.89)	(4.59)
Transportation expenses	**(3.36)**	(2.42)	(2.00)	(2.95)	(2.74)
Operating netback after hedging	**19.01**	22.77	30.52	24.97	23.72

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

SELECTED QUARTERLY INFORMATION CONTINUED

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

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

SELECTED QUARTERLY INFORMATION CONTINUED

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

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

Forward-looking Information Advisory

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

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

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

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

Independent Reserves Evaluation

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

Oil and Gas Definitions

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

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

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

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

gross means:

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

net means:

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

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

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

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

Abbreviations

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

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

INDEPENDENT AUDITOR'S REPORT

March 8, 2016

TO THE SHAREHOLDERS OF SEVEN GENERATIONS ENERGY LTD.

We have audited the accompanying consolidated financial statements of Seven Generation Energy Ltd. and its subsidiary, which comprise the consolidated balance sheet as at December 31, 2015 and the consolidated statement of income (loss) and comprehensive income (loss), statement of changes in equity and statement of cash flows for the year then ended, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audit is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Seven Generations Energy Ltd. and its subsidiary as at December 31, 2015 and their financial performance and their cash flows for the year then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Other Matters

The financial statements of Seven Generations Energy Ltd. for the year ended December 31, 2014, were audited by another auditor who expressed an unmodified opinion on those statements on March 10, 2015.

PricewaterhouseCoopers LLP

Chartered Professional Accountants
Calgary, Alberta

CONSOLIDATED BALANCE SHEETS

(thousands of Canadian dollars)

As at December 31	Notes	2015	2014
Assets			
Current assets			
Cash and cash equivalents	6	**405,046**	848,136
Accounts receivable		**76,439**	64,417
Risk management contracts	19	**98,570**	138,122
Deposits and prepaid expenses		**12,418**	9,355
		592,473	1,060,030
Risk management contracts	19	**52,996**	997
Oil and natural gas assets	7	**3,109,503**	2,049,760
Goodwill		**4,010**	4,010
		3,758,982	3,114,797
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	9	**187,883**	268,231
Risk management contracts	19	**18,320**	-
		206,203	268,231
Risk management contracts	19	**10,039**	-
Senior notes	10	**1,546,761**	813,880
Deferred credits		**850**	973
Decommissioning liabilities	11	**79,109**	52,163
Deferred income taxes	12	**129,370**	68,624
		1,972,332	1,203,871
Equity			
Share capital	13	**1,775,673**	1,719,779
Contributed surplus		**61,810**	54,684
Retained earnings (Deficit)		**(50,833)**	136,463
		1,786,650	1,910,926
		3,758,982	3,114,797

Commitments and contingencies (Note 22)

Subsequent event (Note 24)

See accompanying notes to the consolidated financial statements.

Approved by the Board of Directors

Dale Hohm

Kent Jespersen

CONSOLIDATED STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)

(thousands of Canadian dollars, except per share amounts)

Year ended December 31	Notes	2015	2014
Revenues			
Liquids and natural gas sales		**591,924**	534,833
Royalties		**(57,898)**	(51,890)
		534,026	482,943
Risk management contracts			
Realized gain	19	**150,580**	9,737
Unrealized gain (loss)	19	**(15,911)**	141,765
Other income		**8,014**	4,987
		676,709	639,432
Expenses			
Operating	16	**101,188**	54,261
Transportation		**60,336**	34,833
General and administrative	17	**24,343**	20,258
Depletion, depreciation and amortization	7	**283,535**	159,447
Stock based compensation	14	**13,987**	11,950
Finance expense	18	**102,011**	63,641
Foreign exchange loss		**219,301**	47,673
Liquidity event expense	23	**-**	35,947
Gain on disposition of assets	7	**(2,602)**	(4,286)
		802,099	423,724
Income (loss) before taxes		**(125,390)**	215,708
Taxes			
Current income tax expense	12	**104**	-
Deferred income tax expense	12	**61,802**	71,508
		61,906	71,508
Net income (loss) and comprehensive income (loss)		**(187,296)**	144,200
Net income (loss) per share	15		
Basic		**(0.75)**	0.73
Diluted		**(0.75)**	0.64

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(thousands of Canadian dollars)

	Notes	Share capital	Contributed surplus	Retained earnings (deficit)	**Total**
Balance at December 31, 2013		790,064	45,626	(7,737)	827,953
Net income for the period		-	-	144,200	144,200
Issue of common shares	13	931,500	-	-	931,500
Share issue costs (net of deferred tax)	13	(36,637)	-	-	(36,637)
Stock based compensation	14	-	18,012	-	18,012
Exercise of stock options and performance warrants	13, 14	34,852	(8,954)	-	25,898
Balance at December 31, 2014		1,719,779	54,684	136,463	1,910,926
Net loss for the period		-	-	(187,296)	(187,296)
Tax rate change on share issue costs	13	1,056	-	-	1,056
Stock based compensation	14	-	20,014	-	20,014
Exercise of stock options and performance warrants	13, 14	54,838	(12,888)	-	41,950
Balance at December 31, 2015		**1,775,673**	**61,810**	**(50,833)**	**1,786,650**

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(thousands of Canadian dollars)

Year ended December 31	Notes	2015	2014
Operating activities			
Net income (loss) for the period		**(187,296)**	144,200
Items not affecting cash:			
Deferred income tax expense	12	**61,802**	71,508
Depletion, depreciation and amortization	7	**283,535**	159,447
Unrealized (gain) loss on risk management contracts	19	**15,911**	(141,765)
Stock based compensation	14	**13,987**	11,950
Non-cash finance expenses	18	**1,626**	691
Gain on disposition of assets	7	**(2,602)**	(4,286)
Unrealized foreign exchange loss		**227,769**	50,311
Decommissioning expenditures	11	**-**	(206)
Other		**(123)**	(70)
Changes in non-cash working capital	21	**(34,492)**	10,129
Cash provided by operating activities		**380,117**	301,909
Financing activities			
Issue of shares for cash	13	**-**	931,500
Issue of shares on option exercises	13	**41,950**	25,898
Share issue costs	13	**-**	(48,849)
Issue of debt	10	**515,052**	356,342
Debt issue costs	10	**(11,329)**	(9,840)
Cash provided by financing activities		**545,673**	1,255,051
Investing activities			
Oil and natural gas asset additions	7	**(1,308,973)**	(1,120,336)
Proceeds on disposition of property	7	**-**	9,420
Changes in non-cash working capital	21	**(61,001)**	91,512
Cash used in investing activities		**(1,369,974)**	(1,019,404)
Unrealized foreign exchange gain on cash held in foreign currencies		**1,094**	3,095
Increase (decrease) in cash and cash equivalents		**(443,090)**	540,651
Cash and cash equivalents, beginning of year		**848,136**	307,485
Cash and cash equivalents, end of year		**405,046**	848,136

Supplementary disclosure of cash flow information (Note 21)

See accompanying notes to the consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

AS AT AND FOR THE YEARS ENDED DECEMBER 31, 2015 AND 2014

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

1. NATURE OF BUSINESS

Seven Generations Energy Ltd. ("Seven Generations" or the "Company") is incorporated under the *Canada Business Corporations Act* and commenced operations in 2008. Seven Generations is a Canadian company focused on the exploration, development and production of oil and natural gas properties in western Canada. Seven Generations' principal place of business is located at 300, 140 – 8th Avenue SW., Calgary, Alberta T2P 1B3. The Company's Class A common shares are publicly traded on the Toronto Stock Exchange under the symbol "VII".

2. BASIS OF PREPARATION

These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

These consolidated financial statements have been prepared on a historical cost basis, except for certain financial instruments which are measured at fair value as explained in Note 18. The consolidated financial statements are presented in Canadian dollars, which is Seven Generations' functional currency.

These consolidated financial statements include the accounts of Seven Generations and its wholly-owned subsidiary, Seven Generations (US) Corp. ("Seven Generations US"). All inter-entity transactions have been eliminated.

The preparation of the consolidated financial statements requires Management to use judgments, estimates and assumptions that affect the reported amounts of assets, liabilities and the disclosure of contingencies at the date of the financial statements, and revenues and expenses during the reporting period. Accordingly, actual results could differ from those estimated. Significant estimates and judgments used in the preparation of the financial statements are detailed in Note 5.

The consolidated financial statements were approved and authorized for issue by the Board of Directors (the "Board") on March 8, 2016.

Certain comparative figures from prior periods have been reclassified to conform to the current year's presentation. The current portion of deferred credits has been disclosed with Accounts Payable and Accrued Liabilities in Note 9.

3. SIGNIFICANT ACCOUNTING POLICIES

Property, Plant and Equipment

(a) Oil and Natural Gas Assets

Oil and natural gas properties are carried at cost, less accumulated depletion and depreciation and accumulated impairment losses, if any.

Oil and natural gas properties represent all costs directly attributable to development of oil and natural gas reserves after technical feasibility and commercial viability have been established. These include lease acquisitions, geological and geophysical costs, drilling and completion costs, production equipment, pipelines and gathering equipment, processing facilities and associated turnarounds, other directly attributable costs, borrowing costs of qualifying assets and estimates of decommissioning liabilities.

Depletion of intangible oil and natural gas assets is calculated using the unit-of-production method based on estimated recoverable reserves before royalties. Natural gas reserves and production are converted to equivalent barrels of oil based upon the relative energy content (6:1). The depletion base includes capitalized costs, plus future costs to be incurred in developing estimated recoverable proved and probable reserves and excludes the cost of assets not yet available for use. Tangible oil and natural gas assets, including natural gas plants, are depreciated on a straight-line basis over their estimated useful lives.

(b) Exploration and Evaluation Assets

Exploration and evaluation ("E&E") assets are those investments for an area or project for which technical feasibility and commercial viability have not yet been determined. The Company capitalizes all E&E costs after the right to explore has been obtained related to exploration properties, including geological and geophysical costs, land acquisition costs and costs for drilling, completion and testing of exploration wells. When technical feasibility and commercial viability is established, the associated E&E assets are tested for impairment at the lower of cost and the estimated recoverable amount is transferred to property, plant and equipment. Any costs in excess of the estimated recoverable amount are charged to expense.

E&E assets are not amortized.

Farm-in and farm-out arrangements for E&E properties are accounted for at cost. No gain or loss is recognized on the disposition of a working interest through a farm-out arrangement.

(c) Other Fixed Assets

Other fixed assets include office furniture and fixtures, computer equipment and field vehicles. They are carried at cost and depreciated over their estimated useful lives at annual rates ranging from 20 percent to 100 percent.

Financial Instruments

Financial assets and liabilities are recognized when the Company becomes party to the contractual provisions of the instrument and are initially measured at fair value. Transaction costs, other than for financial instruments at fair value through profit and loss, are added to or deducted from the fair value of the financial instrument on recognition. Transaction costs for financial instruments at fair value through profit and loss are recognized immediately in net income (loss).

Measurement in subsequent periods is dependent upon whether the financial instrument has been classified as fair value through profit and loss, available for sale, held to maturity, loans and receivables or other financial liabilities. The classification depends on the nature and purposes of the financial instrument and is determined at the time of initial recognition.

Financial instruments designated as fair value through profit and loss are subsequently measured at fair value with changes to those fair values recognized immediately in net income (loss). Available for sale financial assets are subsequently measured at fair value with changes in fair value recognized in other comprehensive income (loss), net of tax. Amounts recognized in other comprehensive income (loss) for available for sale financial assets are transferred to net income (loss) when realized through disposal or impairment. Held to maturity investments, loans and receivables and other financial liabilities are subsequently measured at amortized cost using the effective interest method less any impairment.

An embedded derivative is a component of a contract that modifies the cash flows of the contract. These hybrid contracts are considered to consist of a host contract plus an embedded derivative. The embedded derivative is separated from the host contract and accounted for as a derivative unless the economic characteristics and risks of the embedded derivative are closely related to the host contract. The Company has no material embedded derivatives.

Impairment

(a) Financial Assets

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative impact on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in net income (loss). An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. The impairment reversal is recognized in net income (loss).

(b) Non-financial Assets

The carrying amount of property, plant and equipment is reviewed at each reporting date to determine whether there is any indication of impairment. If such indication exists, then the asset's recoverable amount is estimated. For goodwill, an impairment test is completed each year or when indicators of impairment exist. E&E assets are assessed for impairment when they are reclassified to property, plant and equipment and also if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit" or "CGU"). The recoverable amount of a CGU is the greater of its value in use and its fair value less costs to sell.

In assessing value in use, the estimated future cash flows are discounted to their present value using a discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proved plus probable reserves.

For the purpose of impairment testing, the goodwill acquired in a business combination is allocated to the CGUs that are expected to benefit from the synergies of the combination. E&E assets are allocated to related CGUs when they are assessed for impairment, both at the time of any triggering facts and circumstances as well as upon their eventual reclassification to property, plant and equipment.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in net income (loss). Impairment losses recognized in respect of CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the units and then to reduce the carrying amount of the other assets in the unit (or group of units) on a prorata basis.

An impairment loss in respect of goodwill is not reversed. In respect of oil and natural gas assets, impairment losses recognized in prior years are assessed at each reporting date for any indication that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates that were used to determine the recoverable amount when the impairment was recognized. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion, depreciation and amortization, if no impairment loss had been recognized.

Provisions

(a) General

Provisions are recognized when the Company has a present obligation (legal or constructive) as a result of a past event, it is probable that the Company will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. The amount recognized as a provision is the best estimate of the consideration required to settle the present obligation at the end of the reporting period, taking into account the risks and uncertainties surrounding the obligation. When a provision is measured using the cash flows estimated to settle the obligation, its carrying amount is the present value of those cash flows where the effect of the time value of money is material.

(b) Decommissioning Liabilities

The Company records a liability for obligations associated with the decommissioning of its oil and natural gas assets in the period in which they are incurred, normally when the asset is purchased or developed. On recognition of the liability, there is a corresponding increase in the carrying amount of the related asset, which is depleted on a unit-of-production basis over the life of the reserves. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to earnings. Estimates used are evaluated on a periodic basis and any adjustments are applied prospectively. Actual costs incurred upon settlement of the obligations are charged against the liability.

Income Taxes

Income tax comprises current and deferred taxes. Income tax is recognized in net income (loss), except when it relates to items that are recognized in other comprehensive income (loss) or directly in equity, in which case the related tax expense or recovery is also recognized in other comprehensive income (loss) or equity, respectively.

Current income tax expense is the expected cash tax payable on the taxable income for the period, using tax rates that have been enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized on temporary differences between the carrying amount of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax liabilities are generally recognized for all temporary differences, except for temporary differences arising from goodwill or from the initial recognition (other than in a business combination) of other assets and liabilities in a transaction that affects neither taxable income nor accounting net income (loss). Deferred income tax is determined on a non-discounted basis using tax rates that have been enacted or substantively enacted at the reporting date and that are expected to apply in the periods that the temporary differences reverse. A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary differences can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

Stock Based Compensation

Compensation cost attributable to stock options, performance warrants, deferred share units ("DSUs") and performance and restricted share units ("PRSUs") granted to employees, officers, and directors of Seven Generations is measured at fair value at the date of grant and expensed over the vesting period with a corresponding increase in contributed surplus. Fair value is determined using the Black-Scholes option pricing model. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of stock options, performance warrants and PRSUs that vest, whereas DSUs vest immediately. The performance share units ("PSUs") are granted with certain market conditions, specified at the grant date as determined by the Company's Board of Directors. If the Company satisfies the market conditions, a pre-determined adjustment factor is applied to PSUs eligible to vest at the end of the performance period, based upon the relative share price performance of the Company compared to a peer group over the performance period. The expense recognized over the vesting period of PSUs is the fair value of the PSUs with an estimated adjustment factor. If the actual final adjustment factor is higher than estimated at grant, additional expense is recognized on vesting for the incremental fair value.

Upon the exercise of the stock options, performance warrants, DSUs, PSUs and RSUs, consideration paid together with the amount previously recognized in contributed surplus is recorded as an increase to share capital. The Company's DSU and PRSU plans allow the holder of an DSU or PRSU to receive a cash payment or its equivalent in fully-paid common shares, at the Company's discretion, equal to the fair market value of the Company's Class A common shares calculated at the date of such payment. The Company does not intend to make cash payments under the DSU or PRSU plans and, as such, the PRSUs are accounted for within equity.

Business Combinations and Goodwill

Business combinations are accounted for using the acquisition method. The cost of an acquisition is measured as cash paid and the fair value of other assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. The acquired identifiable assets and liabilities assumed, including contingent liabilities, are measured at their fair values at the date of acquisition. Any excess of the cost of acquisition over the fair value of the net identifiable assets acquired is recognized as goodwill. Goodwill is subsequently carried at cost less accumulated impairment losses, if any. Any deficiency of the cost of acquisition below the fair value of the net identifiable assets acquired is credited to net income (loss) in the period of acquisition. Associated transaction costs are expensed when incurred.

Foreign Currency Translation

Monetary assets and liabilities denominated in a foreign currency are translated at the rate of exchange in effect at balance sheet date. Non-monetary assets and liabilities are translated at the historical exchange rate in effect when the asset was acquired or the liability was incurred. Revenues and expenses are translated at average exchange rates for the period. Translation gains and losses are recognized in the statement of net income (loss) and comprehensive income (loss) in the period in which they are incurred and are reported on a net basis.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand, deposits held with financial institutions and other short-term highly liquid investments that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value, with a maturity of 90 days or less.

Revenue Recognition

Revenue from the sale of oil and natural gas is recognized when risk and rewards of ownership are transferred from the Company to its customers.

Borrowing Costs

Borrowing costs incurred for the construction of qualifying assets are capitalized during the period of time that is required to complete and prepare the assets for their intended use. A qualifying asset is an asset that requires a period of one year or greater to complete or prepare for its intended use. All other borrowing costs are recognized in net income (loss) using the effective interest method. The capitalization rate used to determine the amount of borrowing costs to be capitalized is the weighted average interest rate applicable to the Company's outstanding borrowings during the period.

Jointly Operated Assets

The Company's oil and natural gas activities may involve jointly operated assets. The consolidated financial statements of the Company include the Company's share of these jointly operated assets and a proportionate share of the related revenue and costs.

Per Share Information

Basic per share information is calculated on the basis of the weighted average number of common shares outstanding during the period. For diluted per share information, the weighted average number of shares outstanding is adjusted for the potential number of shares which may have a dilutive effect on net income (loss). Diluted per share information is calculated using the treasury stock method which assumes that proceeds received from the exercise of in-the-money stock options plus the unamortized stock based compensation expense would be used to buy back common shares at the average market price for the period.

4. NEW ACCOUNTING POLICIES

Changes in Accounting Policies

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

Future Accounting Policy Changes

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

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

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

5. SIGNIFICANT ACCOUNTING JUDGEMENTS, ESTIMATES AND ASSUMPTIONS

(a) Judgments

The preparation of financial statements in accordance with IFRS requires management to make judgments, estimates and assumptions that affect the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates. The estimates and associated assumptions are based on historical experience and management's judgment regarding other factors that are considered to be relevant and reasonable in the circumstances. Anticipating future events involves uncertainty and consequently the estimates used by management in the preparation of financial statements may change as future events unfold, additional experience is acquired or the Company's operating environment changes.

IFRS requires that the Company's oil and natural gas properties be aggregated into CGUs, based on their ability to generate largely independent cash flows, which are used to assess the properties for impairment. The determination of the Company's CGUs is subject to management's judgment. The Company's assets are currently held in one CGU.

The Company applies judgment in determining the transfer of risks and rewards of ownership from the Company to its customers. Oil and natural gas revenues are recognized in accordance with this transfer, which typically occurs upon title of asset transfer, at which point cash consideration is receivable, or as products are taken in kind as consideration and the Company has no continuing involvement with the goods or services provided.

The Company assesses revenue agreements using specific criteria to determine whether it is acting as an agent or principal. The Company recognizes revenue on a gross basis when the Company is acting in a principal capacity and on a net basis when the Company is acting in an agent capacity. The Company has concluded it acts in an agent capacity for all revenue transactions whereby third party oil and natural gas volumes are purchased and sold, whereby the Company recognizes the net revenues and net losses in other income separately from oil and natural gas revenues.

The determination of the Company's income tax and royalty liabilities requires interpretation of complex laws and regulations. As such, income taxes and royalties are subject to measurement uncertainty. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. In addition, the recoverability of loss carryforwards and investment tax credits is uncertain. The Company records deferred income tax assets and liabilities using income tax rates substantively enacted at the balance sheet date.

(b) Estimates and Assumptions

The amounts recorded for depletion and depreciation of oil and natural gas properties are based on estimated recoverable reserves and future costs. The level of estimated recoverable reserves and associated future cash flows are also key determinants in assessing whether the carrying values of the Company's oil and natural gas assets and goodwill have been impaired. By their nature, these estimates of reserves and future cash flows are subject to measurement uncertainty. Reserve estimates are determined in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook. The determination of reserve estimates involves the exercise of judgment and the use of estimates for oil and natural gas volumes in place, recovery factors, production rates, future commodity prices and future royalty, operating and capital costs.

The Company's provisions for decommissioning liabilities are based on judgments regarding interpretation of current legal and constructive requirements and estimates of future costs and expected timing for remediation. Actual costs may differ from estimated costs because of changes in laws and regulations, reserves, market conditions, discovery and analysis of site conditions and changes in technology.

The Company uses the Black-Scholes model to estimate the fair value of stock options and performance warrants granted. This requires assumptions regarding interest rates, dividend rates, the underlying volatility of the shares and the expected life and forfeitures of the stock options and performance warrants.

The estimated fair values of financial instruments, by their very nature, are subject to measurement uncertainty. Fair value of financial instruments, where active market quotes are not available, are estimated using the Company's assessment of available market inputs and other assumptions. These estimates may vary from the actual prices that will be achieved upon settlement of the financial instruments.

6. CASH AND CASH EQUIVALENTS

As at December 31	**2015**	2014
Cash	**77,142**	1,448
Short term investments, bearing interest at a weighted average rate of 0.7% (December 31, 2014 – 0.8%) [(1)]	**327,904**	846,688
	405,046	848,136

(1) Includes $Nil US term deposit balance as at December 31, 2015 (2014 – US$66.0 million ($76.6 million)).

7. OIL AND NATURAL GAS ASSETS

	Exploration and evaluation	Developed and producing	Other	Total
Cost				
Balance at December 31, 2013	140,342	1,017,254	4,123	1,161,719
Additions	74,119	1,043,944	2,273	1,120,336
Dispositions	-	(5,134)	-	(5,134)
Non-cash capitalized costs [(1)]	-	33,618	-	33,618
Balance at December 31, 2014	214,461	2,089,682	6,396	2,310,539
Additions	**13,474**	**1,293,589**	**1,910**	**1,308,973**
Dispositions and transfers	**(5,407)**	**2,009**	**-**	**(3,398)**
Non-cash capitalized costs [(1)]	**-**	**37,703**	**-**	**37,703**
Balance at December 31, 2015	**222,528**	**3,422,983**	**8,306**	**3,653,817**
Accumulated depletion, depreciation and amortization				
Balance at December 31, 2013	-	100,600	732	101,332
Depletion, depreciation and amortization expense	-	158,387	1,060	159,447
Balance at December 31, 2014	-	258,987	1,792	260,779
Depletion, depreciation and amortization expense	**-**	**282,022**	**1,513**	**283,535**
Balance at December 31, 2015	**-**	**541,009**	**3,305**	**544,314**
Net book value				
Balance at December 31, 2014	214,461	1,830,695	4,604	2,049,760
Balance at December 31, 2015	**222,528**	**2,881,974**	**5,001**	**3,109,503**

(1) Non-cash capitalized costs include $25.3 million (2014 – $27.6 million) of decommissioning obligation assets, land swap additions and $0.4 million non-cash interest and financing (2014 – $Nil) (Note 18).

As at December 31, 2015, the calculation for depletion included an estimated $6.4 billion (2014 – $8.9 billion) for future development capital associated with undeveloped estimated recoverable proved plus probable reserves and excluded $148.8 million (2014 – $144.7 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 year ended December 31, 2015, the Company capitalized $15.8 million (2014 – $9.8 million) of general and administrative expenses based on actual direct salaries and benefits paid to development personnel specifically related to capital activities, including $6.0 million (2014 – $6.1 million) related to stock based compensation.

During the year ended December 31, 2015, the Company capitalized $4.4 million (2014 – $0.5 million) of borrowing costs.

In 2015, 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. The Company recorded a gain of $2.6 million for the year ended December 31, 2015 (2014 – $4.3 million).

At the end of each reporting period, the Company performs an asset impairment review to ensure that the carrying value of its oil and natural gas properties and associated goodwill is recoverable. At December 31, 2015 and 2014, the Company determined that based on fair value less cost to dispose, both its oil and natural gas assets and goodwill were not impaired. The Company used a discount rate of 10 percent on cash flows from proved plus probable reserves. The estimated cash flows were consistent with the estimates of the Company's independent reserves evaluator.

The impairment review was carried out at December 31, 2015 using the following commodity prices estimated by the independent reserves evaluator:

	WTI Crude Oil (US$/bbl)	US Henry Hub Natural Gas Price (US$/MMBtu)	Edmonton Natural Gasolines C5+ (C$/bbl)	Foreign exchange (US$/C$)
2016	45.00	2.50	60.60	0.73
2017	53.60	2.95	70.50	0.75
2018	62.40	3.40	77.00	0.80
2019	69.00	3.70	85.10	0.80
2020	73.10	3.90	87.50	0.83
2021–2025	84.52	4.52	101.30	0.83

8. BANK DEBT

At December 31, 2015, the Company had available an $850.0 million revolving credit facility (2014 – $480.0 million) with a syndicate of banks (the "credit facility"), expiring in May 2018. 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. At December 31, 2015 and 2014, no amount was drawn on the credit facility.

As of December 31, 2015, the Company had $38.2 million in letters of credit (2014 – $Nil), of which $16.6 million (US$12.0 million) was issued in US dollars.

9. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

As at December 31	**2015**	2014
Trade	**37,206**	18,849
Accrued liabilities	**150,554**	249,259
Deferred credits	**123**	123
	187,883	268,231

10. SENIOR NOTES

	2015	2014
Balance, beginning of year	**813,880**	414,525
Issuance of debt	**515,052**	356,342
Debt issue costs	**(11,329)**	(9,840)
Unrealized foreign exchange loss	**228,802**	53,319
Amortization of premium and debt issue costs	**356**	(466)
Balance, end of year (1)	**1,546,761**	813,880

(1) Balance of principal less debt issue costs at December 31, 2015 is US$1,116.7 million ($1,547.9 million) (December 31, 2014 – US$701.1 million ($814.3 million)).

On May 10, 2013, the Company closed a private placement of US$400.0 million of senior unsecured notes. The notes bear interest at 8.25 percent per annum (calculated using a 360-day year) payable on May 15 and November 15 of each year, commencing on November 15, 2013. The notes will mature May 15, 2020. After May 15 of each of the following years, the notes are redeemable at the Company's option, in whole or in part, at the following redemption prices (expressed as a percentage of the principal amount of the notes): 2016 at 106.188 percent, 2017 at 104.125 percent, 2018 at 102.063 percent and 2019 at 100 percent. At any time prior to May 15, 2016, the Company may redeem up to US$140.0 million principal amount of the notes at a redemption price equal to 108.250 percent of the principal amount of the notes redeemed with the net proceeds of an equity offering by the Company. In addition, at any time prior to May 15, 2016, the Company may redeem all or a part of the notes at a redemption price equal to 100 percent of the aggregate principal amount plus an applicable premium that will be the greater of: (a) 1.0 percent of the principal amount; and (b) an amount equal to the excess of the present value at such redemption date of the redemption price at May 15, 2016 (106.188 percent) plus all accrued interest due through May 15, 2016 over the principal amount of the notes. The Company reviewed the terms of the senior notes to determine if the prepayment options were embedded derivatives. While the prepayment options meet the definition of an embedded derivative, the Company determined the fair value of the prepayment options was not material and an embedded derivative has not been recorded.

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 percent of par, resulting in gross proceeds to the Company of US$321.0 million. The terms for this second placement are the same as above.

On April 30, 2015, the Company issued US$425.0 million of additional senior unsecured notes that bear interest at 6.75 percent per annum (calculated using a 360-day year) payable on October 31 and April 30 of each year, commencing on October 31, 2015. The notes will mature on May 1, 2023. On or after May 1, 2018, the notes are redeemable at the Company's option, in whole or in part, at the following redemption prices (expressed as a percentage of the principal amount of the notes): 2018 at 105.063 percent, 2019 at 103.375 percent, 2020 at 101.688 percent and 2021 and thereafter at 100 percent. In addition, at any time prior to May 1, 2018, the Company may redeem all or a part of the notes at a redemption price equal to 100 percent of the aggregate principal amount plus an applicable premium that will be the greater of: (a) 1.0 percent of the principal amount; and (b) an amount equal to the excess of the present value at such redemption date of the redemption price at May 1, 2018 (105.063 percent) plus all accrued interest due through May 1, 2018 over the principal amount of the note. The Company reviewed the terms of the senior notes to determine if the prepayment options were embedded derivatives. While the prepayment options meet the definition of an embedded derivative, the Company determined the fair value of the prepayment options was not material and an embedded derivative has not been recorded.

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

The notes are carried at amortized cost, net of transaction costs. The notes accrete up to the principal balance on maturity using the effective interest rate method and an effective interest rate of 7.0 percent, 7.3 percent and 8.6 percent for each respective 2015, 2014 and 2013 issuances. Canadian dollar to US dollar exchange rates at the time of the 2015 issuance of US$425.0 million, 2014 issuance of US$300.0 million and the 2013 issuance of $400.0 million were 0.825, 0.901 and 0.940, respectively.

11. DECOMMISSIONING LIABILITIES

	2015	2014
Balance, beginning of year	**52,163**	23,656
Liabilities incurred	**25,263**	20,873
Changes in estimates	**(1,089)**	2,367
Changes in estimated discount rates	**1,110**	4,311
Decommissioning expenditures	**-**	(206)
Accretion	**1,662**	1,162
Balance, end of year	**79,109**	52,163

The total future decommissioning liability was estimated based on the Company's net ownership interest in all wells and facilities, the estimated costs to abandon and reclaim the wells and facilities and the estimated timing of the costs to be incurred in future periods. The total undiscounted amount of the estimated cash flows required to settle the decommissioning liabilities at December 31, 2015 is approximately $139.1 million (2014 – $90.9 million) which is expected to be incurred over the next 35 years with the majority of costs incurred between 2040 and 2050. At December 31, 2015, a risk free rate of 2.0 percent (2014 – 2.3 percent) and an inflation rate of 2.2 percent (2014 – 2.0 percent) were used to calculate the provision for decommissioning liabilities.

12. INCOME TAXES

The provision for deferred income tax expense is different from the amount computed by applying the combined Canadian federal and provincial income tax rate to income (loss) before income taxes. The reasons for the differences are as follows:

Year ended December 31	2015	2014
Income (loss) before taxes	(125,390)	215,708
Canadian statutory income tax rate	26%	25%
Expected income tax expense (recovery)	(32,601)	53,927
Add (deduct):		
Non-deductible stock based compensation	3,637	2,987
Non-taxable portion of foreign exchange capital losses	29,192	6,308
Provision for uncertain tax position – IceFyre	22,579	-
Unrecognized deferred tax asset	31,629	8,210
Change in tax rates and other	7,470	76
Income tax expense	61,906	71,508

During the year ended December 31, 2015, the Canada Revenue Agency ("CRA") challenged tax losses utilized by the Company which were derived from the Company's predecessor entity, IceFyre Semiconductor Corporation. As a result of the ongoing CRA audit, the Company has applied a provision of $22.6 million against the tax pools.

The Company also recorded a tax recovery of $1.1 million for the rate change effect on share issue costs, presented in Class A Common Shares (Note 13 (b)).

For the year ended December 31, 2015, $0.1 million of current income tax expense was recorded for estimated Illinois state and US federal taxes payable by Seven Generations US. There were no current income taxes for Seven Generations in Canada given its total tax pools of $2.7 billion (2014 – $1.7 billion). Of this amount, $0.7 billion is available for deduction against taxable income for the current fiscal year. Non-capital losses begin expiring in 2034.

Changes in the components of the deferred tax liability are as follows:

	January 1, 2015	Movement	December 31, 2015
Property, plant and equipment	79,147	113,843	192,990
Mark-to-market financial instruments	34,780	(1,514)	33,266
Investment tax credits	(9,127)	9,127	-
Non-capital losses	(4,668)	(58,441)	(63,109)
Decommissioning liabilities	(13,041)	(8,318)	(21,359)
Financing costs	(12,453)	1,559	(10,894)
Unrealized foreign exchange capital losses	(8,895)	(31,148)	(40,043)
Other	(5,329)	4,009	(1,320)
	60,414	29,117	89,531
Unrecognized deferred tax asset	8,210	31,629	39,839
	68,624	60,746	129,370

The gross temporary difference for the unrealized foreign exchange capital losses not being recognized was $147.8 million (2014 – $32.8 million).

	January 1, 2014	Movement	December 31, 2014
Property, plant and equipment	35,957	43,190	79,147
Mark-to-market financial instruments	(661)	35,441	34,780
Investment tax credits	(9,127)	-	(9,127)
Non-capital losses	(4,668)	-	(4,668)
Decommissioning liabilities	(5,914)	(7,127)	(13,041)
Financing costs	(3,758)	(8,695)	(12,453)
Unrealized foreign exchange losses	(2,191)	(6,704)	(8,895)
Other	(310)	(5,019)	(5,329)
	9,328	51,086	60,414
Unrecognized deferred tax asset	-	8,210	8,210
	9,328	59,296	68,624

The changes in the deferred tax liability were allocated to:

Year ended December 31	2015	2014
Income statement	**61,802**	71,508
Share capital	**(1,056)**	(12,212)
	60,746	59,296

13. SHARE CAPITAL

The Company's authorized share capital consists of an unlimited number of Class A Common Voting Shares, Class B Common Non-voting Shares, Preferred A, B, C and D Shares and Special Voting Shares. At December 31, 2015, there are no Preferred Shares or Special Voting Shares issued and outstanding.

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). In December 2014, the Company amended the terms of the stock options and performances warrants, issued prior to the completion of the initial public offering ("IPO"), such that upon exercise, the holders of these instruments will receive two Class A Common Voting Shares (rather than Class B Non-voting Shares) to reflect the two-for-one stock split. The share split has been reflected on a retroactive basis for the Class A Common Voting Shares, stock options, performance warrants and per share information.

The following table summarizes changes to the Company's common share capital:

	2015		2014	
Year ended December 31	**Number (000s)**	**Amount ($)**	Number (000s)	Amount ($)
Class A Common Voting Shares				
Balance, beginning of year	**244,716**	**1,716,050**	185,420	783,514
Issued on IPO (a)	**-**	**-**	51,750	931,500
Share issue costs, net of deferred tax (b)	**-**	**1,056**	-	(36,637)
Issued on exercise of stock options and performance warrants	**8,656**	**41,950**	110	275
Transfer from contributed surplus on exercise of stock options	**-**	**12,888**	-	130
Conversion of Class B Common Non-voting Shares (1)	**1,042**	**3,715**	7,436	37,268
Balance, end of year	**254,414**	**1,775,659**	244,716	1,716,050

(1) On conversion of Class B Non-voting Shares into Class A Common Voting Shares, holders receive two Class A Common Voting Shares for each Class B Non-voting Share converted.

(a) On November 5, 2014, the Company closed an initial public offering ("IPO") for gross proceeds of $931.5 million through the issuance of 51.8 million Class A Common Voting Shares. Share issue costs related to the IPO and equity financing were $51.4 million, including the underwriters' commission for 5 percent of the gross proceeds . Of this amount, the Company expensed $2.5 million (Note 17) in the income statement with the remainder charged against share capital. The Company also recognized a deferred income tax benefit of $12.2 million related to the share issue costs (Note 12).

(b) For the year ended December 31, 2015, the Company recorded a deferred tax recovery of $1.1 million for the rate change effect on share issue costs related to changes in tax rates (Note 12).

	2015		2014	
Year ended December 31	**Number (000s)**	**Amount ($)**	Number (000s)	Amount ($)
Class B Common Non-voting Shares				
Balance, beginning of year	**523**	**3,729**	966	6,550
Issued on exercise of stock options	**-**	**-**	1,770	9,765
Issued on exercise of performance warrants	**-**	**-**	1,505	15,858
Transfer from contributed surplus on exercise of stock options and performance warrants	**-**	**-**	-	8,824
Conversion to Class A Common Voting Shares [1]	**(521)**	**(3,715)**	(3,718)	(37,268)
Balance, end of year	**2**	**14**	523	3,729

(1) On conversion of Class B Non-voting Shares into Class A Common Voting Shares, holders receive two Class A Common Voting Shares for each Class B Non-voting Share converted.

14. STOCK BASED COMPENSATION

Stock Options

The Company's stock option plan was amended and restated on August 27, 2014 (the "New Plan"). The stock options under the New Plan are exercisable for Class A Common 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 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 percent 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.

Prior to the Company's IPO closing on November 5, 2014, Seven Generations had issued stock options to its directors, officers, and employees to acquire up to 12.4 million Class A Common Voting Shares. These stock options ("Pre-IPO stock options") were granted under the stock option plan provided for in the Amended and Restated Shareholder Agreement ("USA") effective while Seven Generations was a private company. The Pre-IPO stock options are exercisable for Class A Common Voting Shares. After the November 5, 2014 closing of the IPO, no additional Pre-IPO stock options may be granted.

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

	2015		2014	
Year ended December 31	**Number (000s)**	**Exercise Price ($)**	Number (000s)	Exercise Price ($)
Balance, beginning of year	**12,385**	**6.71**	13,426	3.49
Granted	**2,340**	**13.19**	2,927	17.11
Exercised	**(2,428)**	**3.74**	(3,650)	2.75
Forfeited	**(327)**	**12.58**	(318)	5.81
Balance, end of year	**11,970**	**8.43**	12,385	6.71

A summary of stock options outstanding and exercisable into Class A Common Voting Shares at December 31, 2015 is as follows:

	Options outstanding		Options exercisable	
Exercise price ($)	Number of options (000s)	Weighted average remaining life (years)	Number of options (000s)	Weighted average remaining life (years)
2.50 – 5.49	4,257	1.9	4,257	1.9
5.50 – 12.49	4,485	6.3	2,122	4.0
12.50 – 17.49	747	7.1	153	5.2
17.50 – 20.20	2,481	5.8	762	5.5
	11,970	4.7	7,294	3.0

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

Year ended December 31	2015	2014
Fair value of options granted ($/option)	**6.67**	7.81
Risk-free interest rate (%)	**0.79**	1.40
Expected life (years)	**5.0**	3.9
Expected forfeiture rate (%)	**4.0**	3.0
Expected volatility (%)	**60.0**	60.0
Expected dividend yield (%)	**-**	-

Performance Warrants

Prior to the Company's IPO closing on November 5, 2014, Seven Generations had issued performance warrants to its directors, officers, and employees to acquire up to 26.0 million Class A Common Non-voting Shares. These performance warrants were granted pursuant to the USA effective while Seven Generations was a private company. The performance warrants are exercisable for Class A Common Voting Shares. Except for the performance warrants that were granted in 2008 and 2009, the terms of which were extended to 2017, the performance warrants have a seven-year term from the date of grant and vest over a period of five years. After the November 5, 2014 closing of the IPO, no additional performance warrants may be granted.

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

	2015		2014	
Year ended December 31	**Number (000s)**	**Exercise price ($)**	Number (000s)	Exercise price ($)
Balance, beginning of year	**25,968**	**5.99**	28,825	5.39
Granted	**-**	**-**	1,350	17.38
Exercised	**(6,228)**	**5.27**	(3,011)	5.27
Forfeited	**(1,247)**	**7.30**	(1,196)	6.31
Balance, end of year	**18,493**	**6.14**	25,968	5.99

A summary of performance warrants outstanding and exercisable into Class A Common Voting Shares at December 31, 2015 is as follows:

	Warrants outstanding		Warrants exercisable	
Weighted average exercise price ($)	Number of warrants (000s)	Weighted average remaining life (years)	Number of warrants (000s)	Weighted average remaining life (years)
3.75 – 5.25	7,907	1.9	6,988	1.8
5.26 – 5.85	2,139	4.0	1,001	3.9
5.86 – 12.50	7,410	2.4	5,969	2.1
12.50 – 17.50	1,037	5.4	216	5.4
	18,493	2.5	14,174	2.1

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

Year ended December 31	2015	2014
Fair value of warrants granted ($/warrant)	**-**	8.87
Risk-free interest rate (%)	**-**	1.40
Expected life (years)	**-**	4.9
Expected forfeiture rate (%)	**-**	3.0
Expected volatility (%)	**-**	60.0
Expected dividend yield (%)	**-**	-

Share Units

On August 27, 2014, the Board adopted a Performance and Restricted Share Unit ("PRSU") Plan and a Deferred Share Unit Plan ("DSU").

The PRSU Plan allows for granting of Restricted Share Units ("RSUs") and Performance Share Units ("PSUs"), to officers and employees of the Company. RSUs and PSUs represent the right for the holder to receive Class A Common Voting Shares or, at the election of the holder and the Company, a cash payment equal to the fair market value of the Company's common shares calculated at the date of such payment. The vesting of PSUs are conditional on the satisfaction of certain performance criteria as determined by the Company's Board of Directors. If the Company satisfies the performance criteria, PSUs become eligible to vest and a pre-determined multiplier is applied to eligible PSUs. RSUs and PSUs granted to date under the PRSU Plan generally vest annually over a three year period.

The following table sets forth a reconciliation of PRSUs exercisable into Class A Common Voting Shares:

Year ended December 31	**2015**	2014
Balance, beginning of year	**-**	-
Granted	**426,546**	-
Exercised	**-**	-
Forfeited	**-**	-
Balance, end of year	**426,546**	-

Of the 426,546 units outstanding on December 31, 2015 under the PRSU Plan, 154,698 are PSUs and 271,848 are RSUs. The fair value of RSUs for the year ended December 31, 2015 was $12.11 per unit using a forfeiture rate of 5 percent.

The DSU Plan allows for granting of Deferred Share Units ("DSUs") to directors of the Company. DSUs represent the right for the holder to receive Class A Common Voting Shares or, at the election of the holder and the Company, a cash payment equal to the fair market value of the Company's common shares calculated at the date of such payment. DSUs granted under the DSU plan generally vest immediately upon grant.

The following table sets forth a reconciliation of DSUs exercisable into Class A Common Voting Shares:

Year ended December 31	**2015**	2014
Balance, beginning of year	**-**	-
Granted	**55,176**	-
Exercised	**-**	-
Forfeited	**-**	-
Balance, end of year	**55,176**	-

The fair value of DSUs for the year ended December 31, 2015 was $13.63 per unit.

15. PER SHARE AMOUNTS

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

Year ended December 31	**2015**	2014
(000s)		
Weighted average number of common shares – basic	**249,549**	198,742
Effect of outstanding stock options and performance warrants (1)	**-**	25,975
Weighted average number of common shares – diluted	**249,549**	224,717

(1) For the year ended December 31, 2015, 6.7 million stock options and 13.9 million performance warrants have been excluded from the diluted earnings per share calculation since these are anti-dilutive as the Company is in a net loss position. Additional potentially dilutive instruments would include 0.1 million DSUs (2014 – 2.4 million anti-dilutive stock options and 1.2 million anti-dilutive performance warrants).

16. OPERATING EXPENSES

Year ended December 31	2015	2014
Equipment rental, maintenance and other	**31,413**	20,584
Trucking and disposal	**30,510**	15,339
Chemicals and fuel	**15,008**	3,438
Staff and contractor costs	**15,981**	9,474
Other	**8,276**	5,426
Operating expenses	**101,188**	54,261

17. GENERAL AND ADMINISTRATIVE EXPENSES

Year ended December 31	2015	2014
Personnel	**18,844**	12,912
Professional fees	**1,780**	2,636
Rent	**1,584**	1,210
Information technology costs	**2,347**	1,310
Other office costs and travel	**5,161**	3,403
IPO expenses	**-**	2,506
Gross expenses	**29,716**	23,977
Capitalized salaries and benefits	**(3,619)**	(2,661)
Operating overhead recoveries	**(1,754)**	(1,058)
General and administrative expenses	**24,343**	20,258

18. FINANCE EXPENSE

Year ended December 31	2015	2014
Interest on senior notes	**98,887**	61,303
Revolving credit facility fees and other	**5,512**	2,142
Amortization of premium and debt issue costs	**356**	(466)
Accretion	**1,662**	1,162
Total finance costs	**106,417**	64,141
Capitalized borrowing costs (1)	**(4,406)**	(500)
Finance expense	**102,011**	63,641

(1) Non-cash interest was $0.4 million (2014 – $Nil) (Note 7).

19. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT CONTRACTS

Financial Instrument Classification and Measurement

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

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

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

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

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

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

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

Financial Assets and Financial Liabilities Subject to Offsetting

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

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

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

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

Credit Risk

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

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

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

Market Risk

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

(a) Commodity Price Risk

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

Risk Management Contracts

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

Commodity	Period	Notional	Average Price/Unit (1)
Natural gas (2)	Q1 2016	120,000 MMBtu/d	US$3.20
Natural gas (2)	Q2 2016	120,000 MMBtu/d	US$3.20
Natural gas (2)	Q3 2016	120,000 MMBtu/d	US$3.20
Natural gas (2)	Q4 2016	130,000 MMBtu/d	US$3.18
Natural gas (2)	Q1 2017	140,000 MMBtu/d	US$3.20
Natural gas (2)	Q2 2017	100,000 MMBtu/d	US$3.17
Natural gas (2)	Q3 2017	90,000 MMBtu/d	US$2.99
Natural gas (2)	Q4 2017	90,000 MMBtu/d	US$2.99
Natural gas (2)	Q1 2018	60,000 MMBtu/d	US$2.85
Natural gas (2)	Q2 2018	50,000 MMBtu/d	US$2.81
Natural gas (2)	Q3 2018	40,000 MMBtu/d	US$2.76
Natural gas (2)	Q4 2018	40,000 MMBtu/d	US$2.76
Oil (3)	Q1 2016	12,000 bbls/d	C$70.00 - $80.89
Oil (3)	Q2 2016	13,000 bbls/d	C$70.00 - $80.83
Oil (3)	Q3 2016	14,000 bbls/d	C$70.07 - $80.13
Oil (3)	Q4 2016	14,000 bbls/d	C$70.07 - $80.13
Oil (3)	Q1 2017	12,000 bbls/d	C$69.67 - $82.01
Oil (3)	Q2 2017	7,000 bbls/d	C$68.71 - $80.14
Oil (3)	Q3 2017	7,000 bbls/d	C$68.44 - $75.56
Oil (3)	Q4 2017	7,000 bbls/d	C$68.44 - $75.56
Oil (3)	Q1 2018	6,000 bbls/d	C$68.18 - $74.80
Oil (3)	Q2 2018	6,000 bbls/d	C$68.18 - $74.80
Oil (3)	Q3 2018	1,000 bbls/d	C$65.00 - $76.00
Foreign exchange swap (4)	Q1 2016	US$34.9 million	C$1.2550
Foreign exchange swap (4)	Q2 2016	US$34.9 million	C$1.2550
Foreign exchange swap (4)	Q3 2016	US$35.3 million	C$1.2550
Foreign exchange swap (4)	Q4 2016	US$38.0 million	C$1.2597
Foreign exchange swap (4)	Q1 2017	US$40.5 million	C$1.2572
Foreign exchange swap (4)	Q2 2017	US$28.9 million	C$1.2730
Foreign exchange swap (4)	Q3 2017	US$24.7 million	C$1.3215
Foreign exchange swap (4)	Q4 2017	US$24.7 million	C$1.3215
Foreign exchange swap (4)	Q1 2018	US$15.4 million	C$1.3586
Foreign exchange swap (4)	Q2 2018	US$12.8 million	C$1.3661
Foreign exchange swap (4)	Q3 2018	US$10.2 million	C$1.3786
Foreign exchange swap (4)	Q4 2018	US$10.2 million	C$1.3786

(1) For swap contracts, the average put and call price has been calculated for the above table.

(2) Chicago Citygate gas price.

(3) West Texas Intermediate oil price.

(4) US Dollar sales.

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

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

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

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

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

(b) Interest Rate Risk

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

(c) Foreign Currency Exchange Risk

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

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

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

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

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

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

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

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

Liquidity Risk

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

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

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

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

20. CAPITAL MANAGEMENT

The capital structure of the Company is as follows:

As at December 31	**2015**	2014
Total debt [(1)]	**1,546,761**	813,880
Total equity [(2)]	**1,786,650**	1,910,926
Total capital	**3,333,411**	2,724,806

(1) Senior unsecured notes.

(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 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 credit facility (Note 8) and debt financings (Note 10). The Company endeavors 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 had adjusted working capital of $306.1 million (current assets less current liabilities excluding current portion of risk management contracts and deferred credits) plus $812.0 million of credit facility capacity creating available funding of $1.1 billion at December 31, 2015. The Company plans to use these funds, along with funds from operations, and the funds raised in February 2016 (Note 24) for the execution of its 2016 capital program.

Refer to Note 10 for non-financial covenants on the senior unsecured notes.

21. SUPPLEMENTAL CASH FLOW INFORMATION

Change in Non-cash Working Capital

Year ended December 31	**2015**	2014
Accounts receivable	**(13,222)**	(33,917)
Deposits and prepaid expenses	**(3,064)**	(6,776)
Accounts payable and accrued liabilities	**(79,207)**	142,334
	(95,493)	101,641
Relating to:		
Operating activities	**(34,492)**	10,129
Financing activities	**-**	-
Investing activities	**(61,001)**	91,512

Other Cash Flow Information

Year ended December 31	**2015**	2014
Cash interest paid	**94,050**	57,271
Cash taxes paid	**-**	-

22. COMMITMENTS AND CONTINGENCIES

The following table lists the Company's estimated material contractual commitments at December 31, 2015:

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

(1) Balance represents US$1.1 billion principal converted to Canadian dollars at the closing exchange rate for the period end.

(2) Subject to completion of certain pipeline and facility upgrades by the counterparty transportation company.

(3) The Company is committed under operating leases for office premises.

(4) In November 2014, the Board of Directors approved a retention bonus plan for management and employees in aggregate of $6.0 million, payable over the two-year period starting November 5, 2014. Of this amount, $2.7 million is payable in 2016.

23. RELATED PARTY TRANSACTIONS

Key management personnel are comprised of all directors and officers of the Company.

In November 2014, the Board of Directors approved a retention bonus plan for management and employees. The retention bonuses will be payable in four equal installments payable every six months starting on May 5, 2015. Each installment payment will be contingent upon the individual being employed by the Company on the date of payment. The maximum retention bonuses will be $6.0 million, payable over the two-year period starting November 5, 2014. Amounts paid to directors and officers are disclosed in the table below.

Pursuant to the USA, the Company was obligated to compensate, with cash or shares, certain directors, officers and employees prior to the completion of a change of control, liquidity event or qualified initial public offering (the "Liquidity Event"). With the closing of the IPO on November 5, 2014, the Liquidity Event condition was satisfied and the Company recognized a liability of $36.0 million. The settlement of the liability was approved by the Board and was paid in cash in 2015. Amounts paid to directors and officers are disclosed in the table below.

The amounts recognized in the consolidated financial statements for transactions with key management personnel are as follows:

Year ended December 31	2015	2014
Salaries, benefits and other short-term compensation	**8,785**	6,276
Stock based compensation	**8,884**	9,538
Retention expense	**1,368**	-
Liquidity event expense [(1)]	**-**	20,090
	19,037	35,904

(1) Amount expensed in 2014 on closing of the IPO. The allocation of payments to key management personnel was determined in 2015.

24. SUBSEQUENT EVENT

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

READER ADVISORY

FORWARD-LOOKING INFORMATION ADVISORY

This document contains certain forward-looking information and statements that involve various risks, uncertainties and other factors. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "should", "believe", "plans", and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this document contains forward-looking information and statements pertaining to the following: the Company's objectives, strategies, vision and competitive strengths; expected transportation capacity and future deliveries; the Company's ability to deliver on its growth objectives and meet the commitments in its marketing and transportation agreements; changes to be implemented under the new Alberta royalty framework and their impact on the Company; changes to laws and regulations and their impact on the oil and gas industry and the Company; the Company's future competitive position; forecast break-even prices required to achieve specified internal rates of return; the impact of commodity price fluctuations on 7G and its competitors; impact of innovation and efficiency measures; forecast supply-cost sensitivities; projected internal rates of return; potential for commercial development of 7G's Deep Southwest assets; ability to derive optimal value from the Company's resources; market predictions; ability to maintain a superior operating margin; opportunities to underpin major investments and access new markets and achieve differentiated netbacks; exploitable resources and production potential; forecast production, production guidance, production declines and production profiles; expectation that seismic activity from the Company's activities will not result in damage to property or the biophysical environment; ability to achieve positive free cash flow and full-cycle returns; expectation that the Cutbank plant will be processing incremental gas volumes in the second quarter of 2016; total field gathering, transportation and processing capacity; planned capital investment; sources and uses of funds; the number of rigs to be utilized; planned number of wells to be drilled, completed and tied-in; the planned construction of additional super pads and a second condensate stabilizer at the Karr facility and the anticipated timing thereof; the number of future drilling opportunities; ability to subcontract capacity on the Alliance Pipeline; potential benefits of vertical integration or a hybrid midstream business model; and opportunities to acquire new reserves and resources.

For a description of the material factors and assumptions that were used to develop the forward looking information that is contained herein, please refer to the "Forward Looking Information Advisory" that is included in the Management's Discussion and Analysis, dated March 8, 2016, for the year ended December 31, 2015 (the "MD&A") that is provided herein. Actual results could differ materially from those anticipated in the forward-looking information as a result of the risks and risk factors that are set forth in the Annual Information Form, dated March 8, 2016, for the year ended December 31, 2015 (the "AIF"), which is available on the SEDAR website at www.sedar.com. For additional information about these risk factors, please consult the AIF and the "Forward Looking Information Advisory" that appears in the MD&A. For additional information pertaining to financial outlooks and future-oriented financial information, please refer to the "Forward Looking Information Advisory" in the MD&A. For additional information pertaining Non-IFRS measures, including "Funds from Operations" and "Operating Netback" please refer to "Non-IFRS Financial Measures" in the MD&A.

The forward-looking information and statements contained in this document speak only as of the date hereof, and the Company does not assume any obligation to publicly update or revise them to reflect new events or circumstances, except as may be required pursuant to applicable laws.

Advisory Regarding the Presentation of Reserves and Resources

Estimates of the Company's reserves are based upon the reports prepared by McDaniel & Associates Consultants Ltd. ("McDaniel"), the Company's independent qualified reserves evaluator, as at December 31, 2015. The estimates of reserves provided in this document are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided in this in this document and the differences may be material. Estimates of net present value of future net revenue attributable to the Company's reserves do not represent fair market value and there is uncertainty that the net present value of future net revenue will be realized. There is no assurance that the forecast price and cost assumptions applied by McDaniel in evaluating Seven Generations' reserves will be attained and variances could be material

Seven Generations has adopted the standard of 6 Mcf:1 bbl when converting natural gas to oil equivalent. Condensate and other NGLs are converted to oil equivalent at a ratio of 1 bbl:1 bbl. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf:1 bbl is based roughly on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at 7G's sales points. Given the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalency of 6 Mcf: 1 bbl, utilizing a conversion ratio at 6 Mcf: 1 bbl may be misleading as an indication of value.

The reserves and resources information contained in this document should be reviewed in conjunction with the AIF, which contains important additional information regarding the independent reserves and resources evaluations that were conducted by McDaniel and a description of, and important information about, the reserves and resources terms used in this document. The AIF is available on the SEDAR website at www.sedar.com.

Definitions

Below are definitions for certain terms and abbreviations that are not already defined under "Oil and Gas Definitions" and "Abbreviations" in the MD&A that is included herein:

"best estimate" is a classification of estimated resources described in the COGE Handbook, which is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual quantities recovered will be greater or less than the best estimate. Resources in the best estimate case have a 50 percent probability that the actual quantities recovered will equal or exceed the estimate.

"COGE Handbook" means the Canadian Oil and Gas Evaluation Handbook maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter), as amended from time to time.

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

"IPO Prospectus" means the supplemented PREP Prospectus dated October 29, 2014 that was prepared in connection with the Company's initial public offering and is available on the SEDAR website at www.sedar.com.

"liquids" refers to oil, condensate and other NGLs.

"Nest" means the primary development block of the Company's Kakwa River Project.

"Nest 1" means the portion of the Nest that falls outside of the Nest 2 area.

"Nest 2" means the Company's higher return prospects that are contained within the Nest.

"Seven Generations" or **"7G"** or the **"Company"** means Seven Generations Energy Ltd.

Abbreviations

CAD	Canadian dollars
C3	propane
C4	butane
C5+	pentanes plus
FX	foreign exchange rate
HH	Henry Hub
IRR	internal rate of return
LPG	liquefied petroleum gas
MM	millions
MMbbl	millions of barrels
tcf	trillion cubic feet
USD	United States dollars

CORPORATE INFORMATION

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Seven Generations shares are traded on the **Toronto Stock Exchange** under the symbol **VII**.