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Presentation

Randy Mah, Senior Manager, Investor Relations

Good morning, everyone. Welcome to Capital Power's seventh annual Investor Day Event here in Toronto. My name is Randy Mah. I'm the Senior Manager of Investor Relations. The event is being webcast so I would like to welcome those people listening to the webcast here today.

Earlier this morning we issued a press release outlining financial and operating targets for 2016 and dividend guidance out to 2018. We also outlined our analysis of the Alberta Climate Leadership Plan and the impact to Capital Power. You will hear more details of that later today.

Before we begin let me cover off the standard disclaimer regarding forward-looking information. Certain information in today's presentation and responses to questions contain forward-looking information. I ask that you refer to the forward-looking information disclaimer at the end of the presentation as well as our disclosure documents filed on SEDAR for further information on the material factors and risks that could cause actual results to differ.

Let me introduce Capital Power's management team and the following people that are presenting today. We have Brian Vaasjo, President and CEO; Bryan DeNeve in his new role as SVP, Finance and CFO; Darcy Trufyn, SVP, Operations, Engineering, and Construction; and Mark Zimmerman, SVP, Corporate Development and Commercial Services, who recently joined the company and has been with us for one month. The management team also consists of Kate Chisholm, SVP, Legal and External Relations, and Jacquie Pylypiuk, Vice President, Human Resources.

So this is the agenda for this morning. We plan on going right through without a break and the presentations will take us to approximately 11:30 and then we'll finish with a Q&A session followed by lunch afterwards.

I'll now turn it over to Brian.

Brian Vaasjo, President & CEO

Thank you, Randy, and good morning and thank you for joining us this morning. I'll start off by speaking to how Capital Power is delivering on its strategy and is well positioned for the future. Then I'll go through the Alberta

Climate Leadership Plan and some of the implications for Capital Power, what we know and what we don't know. Capital Power continues to be a growth-oriented IPP with a growing number of facilities across North America. The company can be characterized as having an excellent group of assets, operated very well, and giving rise to sufficient quality cash flow growth to not only maintain our existing dividend but to grow our dividend as well.

The headline for the day is Capital Power continues to have a focused strategy and the company is well positioned to create shareholder value. We have excellent operations. The impact of the Alberta Climate Change Leadership Plan overall is negative, but there are certainly some positive impacts on our existing assets and our future in Alberta. Despite both short-term lower power prices and the impact of the Alberta plan, we are financially very strong from both a balance sheet and a cash flow perspective. In fact, our financial strength supports a growing dividend. As we look across North America we have significant growth opportunities. Alberta will be a much more significant growth area for Capital Power than we previously expected and we continue to have a growing number of opportunities in the balance of North America.

Today we will address all the elements of our value proposition, which remains unchanged. Starting at the top, Mark will speak to how growth opportunities outside of Alberta, but will also address positioning our substantial growth in Alberta. This, in combination with an upward profile of increasing Alberta power prices, drives significant upside from Alberta. Bryan DeNeve will speak to how strong our financial base can accommodate significant growth without raising any equity. Also, how our recent significant growth in contracted cash flow not only supports our existing dividend but provides the basis for dividend growth over the next three years. Lastly, Darcy will speak to where we are in upping our operational excellence game. And this is not fixing our operations; this is continuing to go from very good to excellent.

We are very proud of what we've been able to do over the last number of years, but when you look at the last two years and our outlook for 2016, we have three years of quantifiable performance improvement. What is very significant is that we are, at the same time, reducing our risks through such initiatives as long-term service arrangements and process improvements. All of this while reducing our costs. Darcy will speak to what that looks like for 2016 and beyond.

Before I speak to the Alberta Climate Leadership Plan I would like to touch on 2015. We are meeting or beating the 2015 corporate priorities we set this time last year. Our plants are meeting the availability targets and new projects have proceeded and, in some cases, been completed as expected. Funds from operations is now expected to come in around target. As measured by targets and accomplishments, 2015 should be a very solid year.

The Alberta government recently announced its Alberta Climate Leadership Plan. At the same time it released the Leach Report, which went into considerable depth of discussion and analysis across the sectors. These were the result of a number of months of consultation and analysis. For Capital Power there has always been three significant inter-related issues. The first is the acceleration of the reduction of coal emissions, what that does to power prices in the short term and of course what it does to Capital Power in terms of its future. The second is the acceleration of renewables. This can be both a significant opportunity and a threat. On the one hand, it signals significant new build in the province, which requires some means of subsidization. It is how that subsidy is struck that leads to the last point, the overall health of the Alberta market. As these pieces come together and the associated carbon tax there was a real possibility that the fundamentals of the merchant markets could be negatively impacted. Capital Power was very active in discussions in all three areas and made very specific proposals addressing each of them. We are very pleased that the structure is very similar to our recommendations.

I will first comment on the carbon competitiveness regulation or CCR. This starts in 2017 at $20 per tonne and moves to $30 per tonne the next year, with some escalation thereafter. The current SGER rules will terminate for 2018. In effect, the electricity generators will pay $30 per tonne for greenhouse gas emissions above an Alberta electricity performance standard. The performance standard will likely be the Shepard facility, given that it's the cleanest facility in the province. An element of the CCR was to eliminate the notional credits that co-generators were receiving and now we end up with what is in effect a level playing field across power generation. The other impact of the carbon tax is to increase power prices, which Mark will address in his presentation in a few minutes.

In regard to renewables, there were two very important elements announced. The first was the timing of the renewable build is related to the retirement of coal plants. Specifically, 50 to 75 percent of the replacement of coal-fired energy retired. This works well in the existing merchant market. The second point was the use of renewable energy credits, or RECs, as a tool to subsidize renewables. The impact of this tool is to maximize the government's risk but also it reduces the number of competitors for these opportunities. The initial focus will be wind and the procurement process should start sometime in 2016. But this positions Capital Power very well to capture a significant amount of the renewable opportunities in Alberta.

This slide addresses the phase-out of coal. On top of the federal capital stock turnover regulations, the Alberta government added a truncation of all coal facilities at 2030. This chart shows the resulting retirement dates. This schedule is subject to change for stranded capital, consumer costs, or system reliability issues. It also doesn't recognize those plants which may shut down earlier for economic reasons. This in part is the mandate for the next phase of the government decisions. In general, we would expect this schedule to be modified by accelerating some of the retirement dates. The facilitator or arbitrator in the next phase will also address compensation. The government has been clear that compensation is appropriate.

One of Capital Power's recommendations was compensation for early retirement and utilizing a pro ration of net book value. This was associated with a much less severe acceleration of retirements but could form a component of compensation in this situation. This is done on a plant-by-plant basis but, in summary, the net book value of our coal assets is about $2 billion. The 2030 retirement drives a 57 percent reduction in remaining life, which would result, following this formula, in compensation of about $1.1 billion. The means for payment could be as simple as cash or equivalent relief from future compliance costs. We do believe the government will work with industry to develop a fair level of compensation and a reasonable approach for delivery of that compensation. One aspect that gives us comfort is that the CCR generates approximately $3 billion a year in cash, which is intended to be revenue neutral and would result in potentially some funds available for compensating power generators.

As I said earlier, through this process it is critical that the Alberta market design be maintained. The direct link between retiring coal capacity and replacing the energy with renewable additions maintains the market fundamentals. It makes sure that overbuilds due to renewables does not happen. Gas-fired generation decisions will be based on pricing signals from market-driven supply and demand. In other words, the market will continue to function as it has for the last 15 years.

The impacts of the Climate Change Leadership Plan varies significantly by time period but overall is negative. These considerations below are before any consideration of compensation. There is no impact of the plan on the 2016 and 2017 time period. In the 2018 to 2020 time period the average EBITDA increases by approximately $20 million a year. The cost of compliance is more than offset by utilization of existing carbon credits, higher power prices for our wind and natural gas assets, and lower compliance costs for the Shepard Energy Centre. For 2021 to 2029 period average EBITDA per year declines by an incremental average of approximately $100 million a year. The incremental increase in power prices is less post 2020. In this period some benefits for Capital Power might be participation in new projects as well as the potential for compensation. As Bryan will describe in a few moments, we see a significant growth in cash flow from now to the next the next decade, including the CCR impact. The post 2030 period is simply very negative with the truncation of the Genesee facilities and Keephills 3 in their existing utilization as coal facilities. But this is where there is very, very clear signals from the government around compensation. Bryan will provide more details on these calculations but overall we are confident that compensation will mitigate much of the negative impact identified above.

I'll now turn it over to Mark.

Mark Zimmerman, SVP, Corporate Development & Commercial Services

Thank you, Brian, and thanks to everyone in the audience here for taking the time to be with us here today.

I've been asked to speak to our growth pipeline for the company going forward and what we would see going into the future here. But for me really what I want to do is leave you three key takeaways by the time I'm done today, and those takeaways really are, as we had communicated in the past, we expected the 2015/2016 time period to be a low point for the Alberta power prices with recovery after that within our key markets and as I'll illustrate today, we think that remains the case. Secondly, as a result of the policy changes that Brian has gone through, we do see a dramatic increase in the growth opportunity set from where it had been in prior years. We are now being presented with a goal of replacing the fleet with renewables and gas-fired generation but a fleet that would take a half a century to build. No small task. Finally, we have the people and the resources to capture our fair share of this growth for our shareholders and our shareholder value. As you will see, Capital Power has been the main builder in Alberta of generation for the past number of years and this building has generally been on time and on budget.

Before I begin I would like to just reiterate the new policy, as Brian went through it, and with that really there's five key elements that have an implication for the growth of the company going forward. First off, the hard cliff on coal. We know we're supposed to be off coal by 2030 overall; however, as Brian mentioned, the specifics around the schedule of that are still to be revealed and that may very well impact the replacement timing and hence the required new builds going forward. Secondly, two-thirds of that retirement has to be replaced with renewables. Of significance is whether this replacement is based on a capacity or energy basis. It is our understanding it will be on an energy basis, which, given wind is one-third the capacity of all thermal generation, we will need to build three times as much wind capacity overall. The gas-fired generation that is to replace one-third of the coal may actually become even more, as we will need likely peaking facilities to support the flexibility that we would need for the reliability of the grid overall with the increase in the renewable build. And, finally, with the carbon tax, the silver lining in the cloud is we do have a team with honed skills that have been very active in developing a portfolio of offset credits in prior years. All of that will be in the context of the maintenance of the market design, which will provide us the price signals for that build as we go forward.

I'll move to speak to each of these elements in more detail.

So let's go back to the basics. In an all energy market we need the price environment as we look forward to provide the basis to give us the build signals for deploying new capital. As I indicated, like last year, we thought that the low point in the Alberta market price regime was going to be 2015/2016. That would be the bottom and we'd start to recover from there. Last year we had thought that that recovery was going to be modest as we moved through 2016/2017 followed by a more robust recovery in the 2019/2020 period as the PPAs started to roll off. This year our expectation is that recovery will be accelerated as one factors in the impact of the CCR or carbon tax. Therefore, for us, we expect the necessary conditions, i.e. the forward price signals, will begin to manifest late in 2016.

The next chart is an illustration of this phenomenon. And I know it's a little busy but perhaps I'll take the time to walk through what we've constructed and why this is important. What I have in front of us here is an illustrative dispatch curve for a typical hour in the Alberta market as we had seen of this year and really what I'm trying to do is illustrate what the impact of the carbon tax would be on this dispatch curve overall. Two points arise as we look at it. The bottom curve is the current merit curve without an implication of a carbon tax and you would see that many of the coal plants would be dispatched at a lower price environment and as you rise up the curve the dispatch decision around the gas plants would come into play depending upon the price of gas at a particular point in time and the heat rate associated with it.

When we overlay a carbon tax that we see through the CCR what we'll see is a couple movements starting to occur, one with the additional variable cost on the coal plant, we would expect many of those will now move up and to the right on the curve overall, requiring a higher price in Alberta in order for it to be dispatched. In the same breath, many of the gas-fired plants will not move of course contingent upon the underlying gas price for the field that they are using. I think what's really key in this example is we do see that in a perfect world one would expect the price to move anywhere from $10 to $15 overall as one incorporates the additional impact of the carbon tax, so we should be seeing the price coming into play. Moving with that, this chart will of course change for any given hour as we see prices of fuel, as we see the level of demand and, just as importantly, as we factor in the level of retirements that Brian had mentioned around the coal plants itself.

As illustrated on our next slide, when we look at the generation stack longer term we also see a reserve margin tightening up, which should also be supportive of price. What you see on this chart right now is the current stack relative to the Alberta electric system operators low-growth scenario going forward and has factored in on the lower spot on the coal fleet the current federal capital stock turnover retirement dates. As you can see in 2015 we currently sit at a healthy reserve margin but over time, as demand grows, that reserve margin will shrink. As the coal plants come off starting in 2019 you see the advent of gas-fired and wind generation being factored in. As I mentioned as well, depending upon the level of retirements though and the timing of it, we may see the timing of those additions coming in. But what is really key is the level of those replacements that we see in the bars that are in there.

If I look at what this means to us in terms of the total investment required, I'll step through the numbers and illustrate why we think we've seen a dramatic increase in the growth potential overall. With the new policy, as has been noted, 6 gigawatts of coal is now to be replaced, and that's to be replaced with 4 gigawatts of renewables and 2 gigawatts of gas over the next 14 years. As I mentioned earlier, the sheer quantity of change is significant. But if you dive a little deeper in this, 4 gigawatts of renewables energy at 150 megawatts per site with a 33 percent capacity factor would require 12 gigawatts of capacity adds or more than 80 sites overall. Assuming a $300 million build per wind site we start to see a very dramatic build required, something in excess of $24 billion over the next 14-year period. Add to that 2 gigawatts of gas to replace the retiring coal and roughly at 500 megawatts a site, $1 billion, there's another $2 billion of investment there, but that's before factoring in the additional gas that will have to be built to fill growth in demand and also, as I mentioned earlier, peakers for creating this building in the grid that we would need given the intermittent nature of wind. To that end, we could well see the total investment potential approaching and even exceeding $30 billion of investment required over the next 14 years. And we believe we're well positioned to secure our share of that build.

And the reason I say that? Well, if I look at the inherent capabilities the organization has, since 2004 we have built over 1,000 megawatts of thermal generation in the province and 150 megawatts of wind. We have demonstrated we have the people in place and are currently active in securing sites. We have demonstrated the stakeholder relations with many of our neighbours, which should help to ensure a social license to build and, very importantly, we have the trained and experienced workforce to design, construct, and operate. In short, we've been the leading developer in the Alberta market-place since 2004, as illustrated on this chart. Given the sheer magnitude of the build we do expect many others will enter the marketplace because a phenomenal investment is required, but we also believe we have a head start in meeting this competitive challenge.

As an example of the competitive advantage I'm referring to I perhaps will use our Genesee operation as an indication. Longer term we could envision in this new environment our Genesee operation becoming another energy centre for us. Of note, we have the building and the transmission infrastructure to the sites, we have very good relations with our neighbours, we have a significant footprint at the site covering over 45 square miles, we have the necessary water rights we would need, and we have the highly effective and skilled workforce already working at the site.

And I would like to point out that we have already been addressing our carbon footprint before the policy was announced. As Darcy will review, we've improved operational efficiencies, thereby naturally reducing emissions. We've also been very active in the consideration of alternate fuels and have considered outright fuel conversion and will pursue those should the economics support it. With the new policy in place we would also expect a portion of the CCR collected could be available for further initiatives to address Alberta's overall carbon footprint. We'll remain attentive to the economics and we will capture those where it makes sense.

We've also spoken to you before in relation to the expansion that we envision putting in place for Genesee. We would expect that this will continue and we remain active in pursuing the necessary steps in making a final decision by March 1st with a targeted in-service of 2019; however, as these further policy details unfold in respect of retirement timing, renewable incentives, and compensation levels, the indicative market pricing will influence the timing ultimately of that build. In short, it's not a question of if it will proceed but rather when. So, to that end, we need to be ready and we're taking the necessary steps to maintain our timing flexibility.

Another example of the economies of scale that we have from our established position is the expansion of Halkirk. As you will recall, in 2012 we built our first Alberta wind farm in Halkirk, which is a 150-megawatt facility. We're now working to duplicate that opportunity and expect it to cost approximately $300 million for our Halkirk 2 facility. The interconnection application has been filed, permitting and supporting studies are underway, and we also expect to achieve economies of scale through construction cost savings from the experience we had with Halkirk 1. As we've experienced for the last three years, we do expect to also realize similar locational advantages arising from the wind resource diversity that we have at this site. In short, as the final detail rules in respect to credit mechanisms to encourage renewable builds are revealed, we're ready to move. And with more than 80 sites required to be built, we should be able to replicate this on a go-forward basis.

All of this then points to what we believe is the significant competitive advantage we have in our key market. Capital Power continues to be a leading developer of generation projects in Alberta. We have delivered more projects on time and on budget than any other major player in the Alberta market. Our in-house development, technical, and construction expertise and the experience gained in the Alberta market assures us of ongoing success. We have a robust pipeline of development opportunities for the renewable and for gas-fired facilities. This includes, as I've mentioned, Halkirk 2 but also many others that we're pursuing for sites and possible joint venture arrangements with other developers as well. We have the infrastructure at both Genesee and Clover Bar and we're looking for these developments to be a combination of both wind and solar so that the intermittent renewable energy together with gas-fired generation provides the robust supply required to meet system needs. We have a diverse portfolio, baseload, peakers and renewables within Alberta, which, when combined with our trading operation, provide for an integrated solution delivering enhanced shareholder value. And finally, as Bryan will review in a little bit here, we have the financial capacity available to us to meet our growth initiatives without having to access the equity capital markets. Overall, given our in depth development and construction experience, portfolio uplift and financial capacity and the robust development pipeline combined with our long and successful operating history, we're well positioned to seize a fair share of this opportunity going forward.

And I perhaps might make a quick note of our capabilities to mitigate the CCR or carbon tax. As I mentioned, our trading group has been a leader in developing and originating credits in Alberta and have accumulated a portfolio that allows us to mitigate over $60 million of exposure over the next three years. In addition, as the new policy places a price on carbon the timing of this portfolio has accelerated and we'll be able to use it to shelter our liabilities in a much quicker timeframe. We believe this expertise and infrastructure that we have will continue to provide value moving forward.

And, finally, we also don't want to place all of our eggs in one basket. While Alberta has, the portfolio of opportunity in Alberta has exponentially grown year over year, we do remain very attentive to balancing our timing and the merchant versus contracted nature of the portfolio overall and, to that end, I would like to give some brief commentary on other non-Alberta greenfield opportunities we're working on, and I should note that this is not taking into account different M&A opportunities that we consider from time to time.

First off I'll work with Canada, start in the west and move east, and then go south. As it relates to British Columbia, we do have a number of sites that we have developed for both peaking, wind, and combined-cycle generation, but of course this will depend upon growth in demand and the impact of LNG requirements as we move forward. Saskatchewan, as you're all aware, Premier Wall did indicate that they would like to move to also having 50 percent of their generation being provided by wind as they move forward and we have been active in securing sites and relationships in that province so if and when the opportunity presents itself we're ready to go. With respect to Ontario, we do expect another large renewable procurement process for wind and solar late 2016 and as well with the additional requirement of renewable we'll again need to consider the additional requirement for peaking capacity to balance the addition of this intermittent supply. We have options on peaking, combined cycle, wind, and solar sites in Ontario and are ready to go should the need arise.

And finally in the U.S. I would point to our Beaufort solar facility. Darcy will cover it in more detail but construction is nearly competed on this 15-megawatt solar project in North Carolina. It's a fully contracted 15-year PPA and we've been able to structure things to take advantage of the tax equity being provided. With respect to Bloom, we have a very exciting site in terms of the wind generation that would see this generate at a 50 percent level. Turbine supply and engineering procurement and construction agreements are nearly finalized. Construction is ready pending take-off agreements. And we're pursuing opportunities with various commercial and industrial off-takers in order to secure the necessary contractual support. Finally, as it relates to other elements, or other sites provided through our Element acquisition, we also have sites in Washington and Oregon, expecting RFPs in late 2016 for wind, solar, and potentially peaking, as well as Arizona for peaking RFPs that are out there.

Generally speaking, we're remaining very active in ensuring that our options remain open for the long term.

So, with that, before passing off to Darcy I would like to reiterate where I started today. I think we see a bright future developing for us in the company with a lot of growth opportunity going forward. In terms of the three key takeaways, just to reiterate, I think we're seeing the low point of the power curve, we're seeing an expanded growth opportunity set, and we have the people and infrastructure in place to secure and capitalize on this future that's being presented to us.

With that, I'll turn it over to Darcy.

Darcy Trufyn, SVP, Operations, Engineering & Construction

Well, thank you, Mark, and good morning, everyone. Today I will provide you with an update of our optimization program in operations and then I'll touch briefly on construction and engineering.

Capital Power has, as Brian said earlier, always had a reputation as being a good operator. Three years ago we began a program, a reliability program to optimize these assets. In the next few slides you'll see that we have been successful at getting more production while spending less money. We have not in any way jeopardized our assets; in fact, when we have run into the unexpected we have done the right thing to maintain those assets and not put them at risk. And, as Brian noted, we've also done a variety of things to mitigate and reduce risks.

For example, we've standardized our maintenance processes across the fleet, we've established robust internal processes to drive learnings and to improve operations, we've entered into long-term service agreements like the one with GE on our LMS units to ensure that we have high start reliability but in addition to ensure that we don't have the unexpected high-cost surprises, and we've also, we also do maintain key critical spares, and that helps us not only shorten our planned outages but also to shorten the unexpected, unplanned occurrences. And as we've improved our operations our safety and environmental performance has also improved, which clearly demonstrates that a productive plant is a safe plant. And earlier this year we actually re-benchmarked our Genesee facilities. We want to ensure that we are tracking and improving our competitiveness versus our industry peers.

Now this slide shows the availability of the CP-operated units since 2012. As you can see, there's a significant upwards improvement in availability. We were hitting over 96 percent this year with our units. The saw-tooth configuration is due to the fact that every second year we have two major outages at our Genesee unit and that brings the overall fleet availability down but, again, the trend is positive and you can see that we believe we can get even better in the coming years.

Now this slide shows the significant amount of additional megawatt hours that we've generated from our thermal units over that same period. It goes hand in hand, more output with higher availability. In 2012 we generated approximately 8.9 million megawatt hours with these thermal units and in 2015 we're producing close to 9.65 million, which is an 8 percent improvement in output.

Now this slide is showing our forced and maintenance outage rate or FMOR for Genesee units and what I've done here is I've taken out the planned outages, so now you remove that saw tooth and what you see is a steady improvement. Now this is the downtime for FMOR but you can see that we are getting better and that we believe we can get even better as we go forward. So a definitive improvement in our performance.

Now this past year we decided to re-benchmark our three Genesee units. You'll recall that we did an extensive benchmarking back in 2012 and we talked about that earlier, a few years ago. We did this re-benchmarking to just recalibrate our metrics and ensure we are making gains against our peers.

Now this slide and to, I guess, your left, it shows where we stood back in 2011, and this would be using the cost data from 2011/2010. They look at two years of costs to take out any irregularities. And you can see that actually G1, G2, G3, they were actually, high costs are actually in the fourth quartile. Overall the Genesee average was quite high compared to the group average and that's for plants of similar size all across North America. We knew we had a cost problem. At this point in time the exchange rate would have been on par roughly Canadian/U.S., the O&M costs that we're benchmarking, it's primarily labour, and certainly the high costs of labour in Alberta when you're compared to the U.S. That is a factor that works against you. But, nonetheless, we knew we had to do something with our cost structure and we've been working on it since and I'll speak to that later on. But we used the same firm to benchmark and, as you can see on the right side, this is now, this is using 2014 and 2013 data. 2015, we're still midway through the year so they used 2014 and 2013. No question the U.S. exchange rate has worked in our favour and it's about a 10 percent advantage, but still, given the high cost of labour, we're actually quite pleased with where we're sitting. We brought it down to low second quartile but it shows a definitive improvement using the same benchmarking firm.

From the availability side, and this is the unavailability but it reverses so it's just, what you're trying to do is get these numbers, these bars very low. In 2011 you can see on your left that it proves that Genesee was in first quartile, so we've always been a good operator. We were having some good years there with G1, G2, and G3 had some technical issues, but overall as a fleet we were below group average and we were in first quartile. When we re-benchmarked again this year, and that's here, you can see that G1, G2, actually the unavailability, but it actually has gone up, which is bad. And we knew we had some issues here. We had some issues with tube repairs and we had some valve issues. But G3 we had brought down significantly. Overall we're still well in the first quartile and certainly well below the group average. What we've done here is we've now looked at using 2015 data, we've used 2015 as we're at year end and we've now got, we think, our issues with our boiler tubes under control, and so this is usually 2014/2015 year data and you can see that we've improved the group average quite a bit and well, well in the first quartile. So we're very, very pleased with this.

At our solid fuel plants in North Carolina, we've made major improvements in our plant output through a variety of changes, and I've spoken about this at previous investor days. The plants are now contributing to the bottom line and for 2016 we again intend to step up our production, as you can see. Now we have significant biomass expertise within Capital Power and coupled with our coal expertise we've been able to apply that, you know, that technical knowledge to making these plants work. This is a complex situation because we're using tri-fuels for these plants. So we've helped the plants but in turn the plants have actually helped us. We've been able to do actually kind of R&D work in terms of looking at alternative fuels to burn and we feel that this is going to help us not only as we look forward to opportunities in Alberta with our coal facilities but also other opportunities across North America.

From a wind perspective, while we're very much dependent on Mother Nature praying for wind, more wind, isn't part of our optimization program. We have to do things to be creative. And we've worked very hard with our LTSA partners to ensure that our turbines are available when the wind blows. We try to maximize availability. And it's also maximizing things, the critical infrastructure, our substations, our inter-connection lines. This past year, for example, our renewables team did a terrific job in terms of compressing our planned outages on our substations and that really helped improve our availability for the year. And we're also doing things to improve our capacity factor. We are working on improving our turbine efficiencies at our facilities and we are, at Quality Wind, in fact implementing a software change that we think will improve our capacity factor and we hope to have that done by the end of the year. So we're doing what we can and we think that that's going to help bring value to our shareholders.

On the cost side, this slide shows our controllable costs, our O&M costs, measured against our kilowatts on our fleet and you can see a trend. It is definitely reducing. For 2016 this low-hanging fruit is getting higher and higher up the tree, it's getting increasingly more challenging to find, but we actually are optimistic we'll be able to find additional ways of spending smarter and we'll try to pull that number down as we go into the year.

Now I've shown this particular slide the past couple of years and, again, what this is intended to do, the dark bottom lines really show our fleet—so this is our fleet as it was in 2012 and you can see, this is O&M spend and how it's been reduced. The orange here is our Capex, our capital expenditures, and you can see there has been a step change but, more importantly, we have really got to where we believe we can sustain our facilities with a very cost-effective Capex, and that's significant. The light blue lines here are the additional O&M cost that come with the addition of new megawatts to our fleet.

Now, as I said, in parallel to our production improvements you can see from this slide that we have made a definitive, a huge improvement in our safety performance, it's measured as TRIF, and also in our environmental reportable incidents. Now both have been improved dramatically. And on safety we believe that for 2015 we'll actually, I believe we may have the best safety performance in Canada for IPPs or utility firms and, in fact, maybe also the best even in the United States. So that's terrific and it just goes again to the point that, you know, an efficient plant is a safe plant.

Now, as Mark noted earlier, we are entering a period of opportunity and I wanted to briefly discuss our engineering and construction capability. In addition to supporting both the Shepard and K2 successful project completions, Capital Power is nearing a very successful completion of our Beaufort solar project in North Carolina. Now Beaufort was a great opportunity for us for a couple key reasons. Firstly, it is our first solar project and it's allowed us to apply our construction and engineering expertise to solar and, secondly, it is our first greenfield U.S. project and it demonstrates that we can successfully work in the United States. And, as I've noted in previous investor days, Capital Power is different. We are very much involved with the construction and engineering of our plants and we think that's good for a couple reasons. One is it ensures for us that we get what we pay for. So later on when it comes to operations we know what we're operating. But, more importantly I think and that is that we help drive the performance outcomes of our projects and we ensure that our contractor stays on to the commitments and we also believe that that helps avoid problems, claims, et cetera. So, as I say, we're very much involved.

On G4, our key personnel are either in place or ready to be transferred to the team to manage the project as we approach LNTP. We've already demonstrated that G4 will be built to a much lower cost per megawatt and that is as a result of infrastructure advantages that we have but it also is because we believe we've designed a better mousetrap. Now for the past several years we've worked very hard at standardizing our procedures and tools and systems across all our operated facilities and on our projects. On Beaufort, for example, even though this is a solar farm we actually have the same maintenance processes that we have at our thermal plants and that's enabled us to have our nearby Southport plant actually take charge of the maintenance of Beaufort when it goes into COD later this month.

And, lastly, because we have the in-house expertise in engineering and operations we are able to solve challenges like those we encountered at Southport and Roxboro in material handling and burning of multi fuels. Further to Mark's comments, we recently improved our fuel burn at Genesee 3 by 3 percent. That's 5,000 tonnes of coal less per month, which also means 3 percent less GHG, and we believe there is much more we can do at all of our coal facilities in that regard. Now this operational and engineering expertise that we have will prove to be very beneficial as we look to alternatives and opportunities with our coal assets in the coming years.

So, in summary, we are tracking extremely well on our optimization program. We have clearly improved performance and output of our fleet, we have reduced and mitigated risks, and in lockstep with our performance improvements we have improved our safety performance. Our operations are very, very stable and we continue to drive improvements and we are putting our energy into proactive maintenance and into opportunities. Capital Power is well positioned for the future.

Thank you and I'll turn it over to Bryan now.

Bryan DeNeve, SVP, Finance & CFO

Thanks Darcy and good morning everybody. My presentation is broken down into the following four topics: I'm going to start with just a brief background on Capital Power's financial strategy, I will then move into our financial guidance for 2016, followed by a bit more detail on the estimated impact of the Climate Leadership Plan, and finally speak to our dividend guidance that you read about in our release.

So, starting with our financial strategy, our business strategies remain very consistent since the IPO and likewise the financial strategy that supports the business strategy remains consistent as well. It continues to be based on maintaining a moderate risk profile underpinned by maintaining an investment-grade credit rating, well-spread debt maturities, ongoing financial flexibility in our capital structure, stable and well-supported dividend, a disciplined growth strategy, and actively managing our foreign exchange and interest rate risks. Maintaining our financial strength ensures we can absorb large construction projects while maintaining our credit metrics as well as being able to use balance sheet financing for investment in the merchant projects in Alberta.

Moving to capital allocation, our first priority is around dividend growth. We have extremely good contracted cash flow and a base that is very supportive of continuing to grow the dividends.

The second priority is looking at growth opportunities in order to increase long-term contracted cash flow and cash flow in general over time and be able to support the growing dividend you need to continue to grow the business. Management's expectation is that even with a growing dividend there will be the ability to fund an average growth investment of approximately $400 million per year. Third, in the absence of growth opportunities we look at alternatives like debt reduction and share buybacks. We recognize that there's different parts of the market cycle where we may not be as competitive on growth opportunities. We have specific hurdles in place that we look at on capital allocation and the extent those growth opportunities aren't meeting those hurdles and if our share price is at a level that we think has a lot of intrinsic value in it, we will look at purchasing shares and/or paying down debt. This has been the case in the latter part of 2015 when Capital Power has completed 5 million of share buybacks and expects to potentially complete an additional 3 million of share buybacks through Q1 2016.

So I just want to turn to the managing the merchant exposure in Alberta. Capital Power has sold forward its baseload capacity for 2016 at an average price of $48 a megawatt hour, which is reflected in our 2016 financial guidance. For 2017 we have sold 35 percent of our base-load power at an average price of $54 a megawatt hour. This would decline to $48 a megawatt hour similar to 2016 if we sell the balance of our portfolio at the current forward price in Alberta of $45 a megawatt hour. Although we are only hedged 12 percent in 2018, this is consistent with the fact that there is very little liquidity in the Alberta market more than two years out. However, this does give us the opportunity to capture the upside from the recovery in Alberta power prices and the price lift that we expect to see from the higher carbon tax on Alberta's coal-fired generating units. We project the price lift to be in the average of $10 to $15 a megawatt hour, as Mark explained earlier.

This slide summarizes the average capture price for Capital Power's generating facilities in Alberta since Q1 2010 and compares it to the average settled price in Alberta over the same period. The average capture price has exceeded the average settled price by 24 percent. Approximately 5 percent of this is due to the fact that our peaking facilities operate in periods of higher pool prices; however, the balance, 19 percent of the premium over the average settled price, is a result of an execution of our forward trading strategies and effective timing of plant outages. The other key outcome of the trading strategy is reducing the volatility of the cash flow from Alberta merchant facilities, which helps mitigate earnings volatility. By hedging forward our baseload output and at times the output from the gas-fired units, Capital Power does take on more operational risk and, as you can see on this graph, this risk materialized in Q2 2015 when we were required to purchase at high spot prices to meet our hedging obligations. However, the loss in that quarter was more than offset by the benefits we experienced in Q1 and Q3 where we dramatically exceeded the average settled price through our hedging strategy.

So moving on to our corporate G&A, Capital Power has continued to reduce its G&A expense through increased efficiency and optimization. In 2015 this included a reduction of 46 FTEs, which resulted in one-time charge of $3 million represented by the orange piece of the bar. Projected G&A in 2016 is 13 percent lower than 2012. Given the inflation rate in Alberta over the same period it reflects a decrease in real terms of 22 percent.

So I'd now like to move to our guidance for 2016. Capital Power expects to continue to increase cash flow in 2016 despite the low pool price environment in Alberta. Funds from operations are expected to be in the range of $380 million to $430 million. The midpoint of the range is $405 million, which is a 4 percent increase over our anticipated FFO in 2015 of $390 million. On a cash flow per share basis the increase is 8 percent, which reflects the impact of the share buybacks we have completed in the latter half of 2015. The projected use of our FFO is consistent with our capital allocation priorities that I described earlier. The adjusted FFO after consideration of $65 million in maintenance Capex is approximately $340 million. A total of $165 million is expected to paid in preferred and common share dividends, which includes a 7 percent increase in the common share dividend in 2016. That leaves approximately $175 million, which is expected to be deployed in growth opportunities.

Going to the sources and uses of cash in 2016, we have the projected FFO at the mid-range of $405 million. The other financing source in 2016 is the debt offering we anticipate will take place in mid-2016, which net of the $134.9 million EPCOR debt maturity we have in March will provide approximately $135 million of additional cash for total sources of $440 million. This will cover the expected preferred and common dividends of $165 million, $65 million of sustaining Capex, and $275 million in growth Capex, which includes $100 million for our share of Genesee 4 and an anticipated $175 million in another contracted growth opportunity in 2016. On the equity side we have no near-term expectations around primary offerings since we are well positioned to finance anticipated growth without any new common equity.

If you look at our balance sheet, we continue to be under-levered to the industry and peers at 33 percent, which is a result of needing to maintain credit metrics that are consistent with our investment-grade credit rating. Over the longer term our target leverage is 40 percent to 50 percent and believe that we'll have the capability of adding additional leverage and driving earnings through a modest increase in leverage as our credit metrics support it. For DBRS we have a BBB rating and for S&P a BBB-rating, both with stable outlooks. These ratings were recently reaffirmed by both DBRS and S&P.

So turning specifically to the credit metrics, these graphs summarize the expectations of DBRS and S&P around their credit metrics. As you see, for 2016 we're well below the DBRS or, sorry, we're well above the DBRS FFO-to-debt metric, as well as their EBITDA-to-adjusted-interest metric. Likewise for S&P we're expected to be well above their expectations of 15 percent FFO-to-debt in 2016 and have lots of capacity on the adjusted debt to adjusted EBITDA in the lower right side of the slide.

So turning to our debt maturity schedule, Capital Power has a well spread out profile of debt maturities. We have had the maturity in December and an EPCOR maturity coming in March 2016. We anticipate coming to market with a medium-term note in mid-2016 to replace maturities. I would note that earlier this year we did extend our credit facilities to 2020.

So I just want to touch on the debt restructuring most of you are aware of. Capital Power is proposing the exchange of Capital Power L.P. medium-term notes for Capital Power medium-term notes. The driver of this change is to simplify Capital Power's overall organizational structure and to reduce reporting obligations by ending CPLP as a reporting issuer and transition long-term credit ratings to only CPX. These changes are expected to reduce ongoing costs by up to $0.5 million per year.

So turning to the Climate Leadership Plan that was announced, and this is redundant with some of what you heard, but I did want to cover these quickly just in the context of what they mean in terms of how we're looking at the financial implications. The most significant impact of course is from the Carbon Competitiveness Regulation, which materially increases our compliance costs relative to the current Specified Gas Emitters Regulation. I will cover a detailed assessment of the CCR in a moment.

As stated in the province's announcement, the structure of the deregulated energy only market will be maintained. On this basis we continue to model prices in Alberta similar to how we have done it historically with the exception of modelling the impact of the higher carbon tax on pool prices and the increased percentage of renewables that are expected to be brought onto the system. Accelerating the retirement dates to 2030 will obviously have an impact on our projected cash flows beyond that point; however, given the fact that we will be receiving compensation for the accelerated retirement dates, we will be able to replace that lost cash flow to investment in replacement natural gas and renewable generating assets. The exact form and timing of the compensation has yet to be determined but certainly could improve our financial results in the near term.

The Carbon Competitiveness Regulation has a material impact on Capital Power's projected earnings. The impact is due to the fact that Capital Power will be obligated to acquire credits or pay a levy to cover the difference between the carbon intensity of our coal-fired facilities to the best-in-class natural gas standard, which we assume will be based on the Shepard energy facility. Depending on the vintage of the coal-fired facility, this is equivalent to an intensity reduction of 55 percent to 65 percent. Under the Specified Gas Emitters Regulation, which it replaces, the reduction was 20 percent.

This graph illustrates the compliance costs associated with Alberta coal-fired generating units on the dollar per megawatt basis. Under the Specified Gas Emitters Regulation, which will end in 2017, the compliance obligation for all coal units in the province are approximately $6 a megawatt hour; however, this obligation increases to approximately $20 a megawatt hour in 2018 when the new carbon tax comes into effect. So I just want to just point out a couple key differences here.

So the blue bar is the compliance costs estimated for all the coal facilities in Alberta. The green bar is estimated cost for Capital Power's coal-fired facilities. And you'll note that our compliance obligation is actually lower and that's driven by the fact that our super critical coal-fired facilities have 20 percent less carbon intensity than the sub-critical coal-fired facilities. The red bars on the graph illustrate our net cost of emissions after we apply our existing inventory of carbon credits as well as our expected cost to develop and procure emission credits on a go-forward basis. So in 2017 and 2018 you see a dramatic reduction in our cost of compliance and that's basically by utilizing our inventory, which basically has an underlying cost of $11 to $12 per tonne. As we move forward in 2019 and 2020 the team that we have in place will continue to develop and procure offsets and we anticipate we'll be able to do that at a lower cost than paying the carbon levy. This would be consistent to what we've been able to do historically.

So this table summarizes our current estimate of how the Carbon Competitiveness Regulation will impact our projected EBITDA based on the information available from the government announcement and from Dr. Leach's climate change report. I want to emphasize it does not include the potential impact of compensation for the accelerated coal retirements or the prospects of additional investment opportunities in Alberta.

The compliance exposure for Capital Power's coal facilities is forecast to increase by approximately $80 million in 2018. However, the increased compliance costs are expected to be offset by the revenue received from higher pool prices, which are expected to increase by $10 to $15 a megawatt hour as a result of the owners of coal units bidding in the higher variable cost into the Alberta power pool. And you'll recall the graph Mark showed of the merit curve in Alberta both pre and post the new tax. In addition, Capital Power expects to meet its 2,000 obligations with the existing GHG inventory and mitigate compliance cost post 2018 with its ability to develop and procure emission credits. In aggregate, over the 2018 to 2020 period Capital Power expects an increase in annual EBITDA by an average of approximately $20 million per year once the impact of the offset inventory and higher pool prices are taken into account.

In 2021 the compliance exposure for Capital Power increases an additional $63 million per year. This is a result of Capital Power now bearing the compliance cost associated with Genesee 1 and 2, which are passed on to the Balancing Pool under the PPA, partially offset by no longer bearing the compliance costs associated with Sundance 5 and 6. The net impact on Capital Power's Alberta portfolio is forecast to be approximately $100 million per year of EBITDA for the 2021 to 2030 period. Despite the projected reduction in the EBITDA due to the new carbon tax, we are still forecasting an increase of cash flow per share of 40 percent to 50 percent from 2015 to 2021 and one of the key reasons that we're expecting or one of the key drivers behind that increase is not only the increasing forward prices based on the forward prices we're seeing in Alberta right now but also by the fact that when Genesee 1 and 2 switch from the PPA to merchant facilities we expect an approximately $60 million to $70 million uplift in the EBITDA. So, again, the incremental impact is $100 million but when we look at our net cash flow going forward we expect it'll increase by 40 percent to 50 percent by 2021. It is important to note that that increase in FFO per share does not include any compensation that may be received for the accelerated retirements through that period or any growth outside of Genesee 4.

So now I'll turn to dividend guidance. The starting point for developing our dividend expectations is the completion of a number of contracted projects since 2012. These include the Quality Wind project, the contracted portion of Halkirk, PDN Wind in Ontario, Macho Springs, which we acquired in New Mexico, the contracted portion of Shepard, K2 Wind, and the Beaufort solar project. Together these assets have increased Capital Power's contracted cash flow by $175 million per year compared to 2012. The significant increase in contracted cash flow has provided the certainty that has allowed Capital Power to start increasing its annual dividend by approximately $10 million in 2014 and again $10 million in 2015, which is roughly an increase of 7 percent each year.

As we look at determining the dividend guidance, one of the primary things that we look at is how much of our contracted cash flow covers our fixed financial obligations. These fixed obligations include our G&A, plant O&M, sustaining Capex, dividend requirements for both preferred and common, and our debt service costs. As we move into 2016 with Shepard and K2 providing a full year of contracted cash flow, we have close to 100 percent coverage of our financial obligations. Once we reach 100 percent coverage we no longer need to rely on margins from Alberta merchant units to meet our financial obligations and any margin generated by Alberta merchant facilities is essentially discretionary cash flow that would be used for growth investments. Or, in the absence of quality growth investments, share buybacks and/or debt repayment.

As shown in this graph, given the amount of power we have hedged in the Alberta market there is no exposure to merchant prices to meet our financial obligations in 2016, and you can see that on how the top lines all converge. In 2017 we only have 35 percent of the baseload portfolio hedged, which means we're still exposed to pool prices to cover our financial obligations. However, the price that needs to be realized is $31 a megawatt hour, which is well below the 2017 forward price of $45 a megawatt hour. The price we need to reach 100 percent coverage in 2018 is in the low $40s, which again is well below the current forward price of $57 a megawatt hour. Based on current forward prices, Capital Power's FFO was projected to increase by 20 percent to 30 percent over the next three years.

I'll maybe just go back to that previous slide just quickly. One item I did want to point out here is the green line. It's showing the percentage coverage of our financial obligations based on current forward prices in Alberta. So in 2018 selling forward at the current forward price will leave us in a position where we have over 120 percent or a ratio of 120 percent to our financial obligations.

So a key question that investors have been asking since the Climate Leadership Plan was released is whether Capital Power expects to be able to maintain growth in its dividend. The answer is that we are providing guidance of a 7 percent annual growth in the dividend through 2018. This expectation is built on the following: When we started our dividend growth in 2014 it was predicated on the growth in our annual contracted cash flow from $225 million to $400 million. The cumulative increase in our dividend through 2018 at 7 percent year growth rate is $50 million, which is only 30 percent of the growth we saw in our contracted cash flow. Second, based on current forward prices our cash flow is expected to increase by 20 percent to 30 percent over the next three years, which is consistent with a 7 percent annual dividend increase, which means there will be no erosion in our FFO payment ratio over the period. The average free cash flow payout ratio over this period is 50 percent, which leaves approximately half of our free cash flow for investment in anticipated growth projects without needing to raise common equity.

So, just to wrap up, a core part of our strategy is around dividend growth. We continue to have one of the lowest payout ratios of Canadian IPPs. We're generating close to $175 million of free cash flow in the bottom of the market cycle. So where does that leave us relative to our peers? This slide compares dividend and adjusted funds from operations yields to our peers as well as payout ratios. When we look at our dividend yield on November 27th of 8.6 percent, it exceeds the average of our peers by 240 basis points. This clearly reflects the current questions around the sustainability of the dividend given the significant uncertainty around the outcome of the Climate Leadership Plan and current low pool price environment in Alberta. However, when you look at our adjusted funds from operations yield of 16.2 percent, it's clear that the sustainability of the dividend should not be in question and, in fact, why we're comfortable in growing that dividend 7 percent per year. The spread to our peers is accentuated when you look at the adjusted funds from operations yield, which is actually 550 basis points above the peer average. Given our dividend guidance for the next three years and our strong cash flow position, we expect to see a decline in our dividend yield to be more in line with our peers.

So, in closing, just like to just recap some key points. We have been effective at managing low Alberta power prices by selling 100 percent of the Alberta commercial power portfolio forward in 2016 at a price of $48 a megawatt hour while continuing to have the ability to capture any potential increase to our remaining length on our non-baseload facilities, which would include the Clover Bar Energy Centre, Joffre, and the Halkirk wind facility. We are benefitting from year-over-year increase in capacity and production from a full year of operations from Shepard and K2 Wind, as well as the addition of Beaufort Solar, which is contracted for 15 years through a PPA. Our 2016 guidance reflects continued strong availability from our existing fleet and cost-saving initiatives in both G&A and O&M. We have effectively used capital to maximize shareholder value by repurchasing 5 million shares to date in 2015 as well as amending the normal course issuer bid to potentially purchase up to an additional 3 million shares through April 2016 in the absence of additional growth opportunities. Based on our projections of strong cash flow in the next three years and beyond, we are providing the dividend guidance of 7 percent increase per year through 2018.

I will now turn it back to Brian.

Brian Vaasjo, President & CEO

Thank you, Bryan.

Each year at this time we provide Capital Power's corporate priorities for the next year, in this case, obviously, 2016. These are the corporate priorities we report on each and every quarter.

First, continued high levels of plant availability, 94 percent, which reflects numerous planned outages; maintenance Capex at $65 million, similar to 2015 but with more facilities on an annualized basis; plant operating and maintenance expenses at $200 million to $250 million.

Our corporate growth priorities include continuing to move Genesee 4 and 5 forward and executing a long-term power purchase agreement in support of an additional new facility.

Funds from operations, our key financial measure, up from a range of $365 million to $415 million in 2015 to $380 million to $430 million in 2016, a growth rate of 4 percent or 8 percent per share. This is due largely to plant additions, lower financing costs, and of course the share buyback program.

In summary, highlights for 2016 are no impact by the Alberta Climate Leadership Plan and we will continue to work with the government on the issues of compensation and market stability. We are forecasting an 8 percent growth in cash flow per share as well as providing guidance on a 7 percent dividend increase.

From a growth perspective, we will continue to move Genesee 4 and 5 forward and we'll continue to develop opportunities in Alberta and through the balance of North America.

Capital Power represents an attractive value proposition, especially when you consider an 8 plus percent dividend yield. The company has excellent existing operations, an outlook of continued growth with operations supporting sustainability of existing dividends, and support the 7 percent annual dividend growth for the next three years.

From a growth perspective, we have numerous good development sites outside of Alberta as well as we are rapidly developing a robust pipeline within Alberta. Capital Power is well positioned to deliver shareholder value.

I'll turn it back over to Randy.

Randy Mah, Senior Manager, Investor Relations

Okay, thanks, Brian.

Before we start the question and answer session I'd like to remind you to use the microphone before asking your question and also to identify yourself. Okay, we're ready for questions.

Paul Lechem, CIBC World Markets

Paul Lechem at CIBC. I was wondering if you can walk us through as you approached your G4 FID how you're thinking about deploying more capital into Alberta, what you need to spend money on a gas plant while your coal plants are being, ah, the timeframe being reduced on those. How do you think about returns? What guarantees you need you that gas won't, you won't go through the same thing with gas plants in 20 years? How are you thinking about the investment around G4?

Brian Vaasjo, President & CEO

Thanks for the question, Paul, because it is a very important issue and I think it helps sort out a little bit of the wheat from the chaff in terms of what's been happening in Alberta and the government position on coal and emissions in general.

So, firstly, in terms of what do we know and in terms of things that are important for making a decision on Genesee 4 to move forward for a full notice to proceed and, just for the information of people who may not be aware, that decision point is during the first quarter of next year. So what we do know is that this government is very supportive of the energy only market in Alberta. I think it's come out a number of times in speeches and in the material that was around the climate change announcement. In particular, the element of tying the level of renewables to the retirement of coal energy capacity or coal energy was actually our recommendation, and that was our recommendation to maintain the market structure. In our view, if it was unhinged to anything and was just an RPS standard or whatever, that could have detrimental impacts on the market, but because they are directly linking it to the retirement of capacity, what it means is that it won't be disruptive to the Alberta market. It won't be disruptive to the energy only market or the signals to build natural gas in that market. So from that perspective our view is going forward the market fundamentals continue to be there.

So the other thing around the whole issue of compensation and the potential for the government, say in some future time period, we need to do something about the natural gas emissions. And certainly there is continuing to be some government risk in any jurisdiction around that. But I think if you look at the model that they've put forward in terms of always going to the best natural gas standard and then from there, increasing the costs of carbon and increasing the standard by what you have to actually meet, that drives decisions in the marketplace to slowly move away from natural gas, so you will see, particularly when you have things such as battery storage or other forms of storage evolving over the next decade and the decade after you'll see less natural gas being built and what you will see is the natural gas that is built and built in the near term will be a necessary portion of the base of generation that's needed in the province.

So, for the time being and looking forward, we would see that a facility such as Genesee 4, and recognize that although it's a combined cycle facility it is extremely efficient, it is the most efficient there is on the planet, and it also is extremely responsive. So you can look at it as almost like a big peaker. So it's not as much baseload generation as something like the Shepard facility but it's more like a hybrid between baseload and peaker. So, from our perspective, if we were talking about building a Shepard facility at this point, an additional one in the market, probably we would be shying away from it. So it's the right hardware to meet the market and doesn't have the same potential exposure as other type of assets may have on a go-forward basis.

So what do we actually need from the government right now in order to make that decision? And we've made it very, very clear. We've made it very clear in recent correspondence to the government, we've made it clear in every meeting, and there must have been 50 of them over the last couple of months where we've said what we need to do or what we need to know to move forward are two things in addition to what's there now. One is, is to understand the principals around compensation, because that is obviously a significant element, but the details and the actual numbers and so on, not practical likely in the timeframe that's available. But the other thing is a schedule of retirements, because as I commented and as Mark commented, the schedule that you saw there is likely not the final schedule.

So what's important for the building of Genesee 4 and potentially Genesee 5 is what retirements are we going to see over the next couple of years? And those are going to be driven by economics. They're going to be driven by a whole number of elements, including the potential for the government actually wanting to see more action from a climate change perspective earlier. So that's to be sorted out and that is one of the major functions of this next step and this arbitrator process is to establish a more definitive schedule of retirement of coal plants. Now that won't impact on ours, we're very, very confident given the age of them, but it may well impact on other assets. And some of them as, I think, as those who monitor the market fairly closely and watch what's dispatched, some units today are barely hanging on in the market and we expect with some of the changes it certainly increases the challenges for some of those facilities to continue operating. So it's how that shapes the fundamental supply/demand question. There is still some issues around that. And so those are the two things we need from the government in a short order to make that investment decision.

Steve Dafoe, Scotiabank

Steve Dafoe with Scotiabank. I understand the depreciation is non-cash and therefore of a lesser focus arguably but would the so-called hard cliff on the coal plants asset life change the depreciation rate for those? And, if it does, when would we expect that to show up in the income statement?

Brian Vaasjo, President & CEO

Well, maybe I'll just jump on that seeing as I have the mic. I mean the element around that is you also have to consider what happens in respect of compensation and how compensation may work from an accounting perspective. In some circumstances it may well be treated as salvage, which in theory results in no change in your depreciation, it just results in your depreciation over, again, a shorter period of time, a smaller amount over a shorter period of time. So a little bit early to be speculating on what and when that might be. We think that some of those types of decisions we won't be making until the dust actually settles on compensation.

Rob Hope, Macquarie

Hi. Rob Hope from Macquarie. I was hoping you could comment on any conversations you've had with the government whether your portfolio of offset credits will still be applicable in the new framework.

Brian Vaasjo, President & CEO

The government has made it clear and actually in Dr. Leach's report it was made clear too that the credits that are there should be transitioned to whatever the new environment is and retain their value. So that's a pretty clear indication. Because there's a lot of people like us who have actually spent—it's not just from improved plant performance, we've actually spent money and gone out and as Mark has indicated, we went out and actually spent money to work with I'll say a carbon source to reduce that emission profile and therefore, in turn get a bank of carbon credits. And some of them are long-term commitments they've made to us in terms of delivering those credits. So it's not just trading, it's actually we've invested in reducing credits from other sources over the last number of years. So the government has said that they will essentially honor those credits.

Andrew Kuske, Credit Suisse

Andrew Kuske, Credit Suisse. This could go for either of the Brian's on how do you think about just the economics of share buybacks versus capital investment because implicitly when, and really explicitly when you're doing share buybacks you get immediate cash flow accretion on a per-share basis to remaining holders but you're also re-leveraging the balance sheet. So maybe just walk us through your economics and the business case and how you think about it.

Bryan DeNeve, SVP, Finance & CFO

So, as I described, our priority is investing in growth opportunities in terms of building up that cash flow to sustain a growing dividend as we move forward, so it's really only those times when those growth opportunities aren't available or meeting our metrics that we'd look to deploy that cash in an alternative endeavour such as share buybacks. One of the things we're very mindful of though in terms of the magnitude of share buybacks is the implications for our credit metrics, so making sure that there isn't any adverse impact on those and maintaining our investment-grade credit rating. So, again, certainly we move to those. Of course the other key is our view of value relative to the current share price. I mean we haven't determined a particular threshold but certainly at where we're trading right now, that adds significant value for shareholders to do those buybacks.

Roger Mortimer, CI Investments

Hi. Roger Mortimer at CI. I just wondered could you expand a little bit on how you think about your forward hedging in 2017 and 2018 relative to your fixed cost requirements.

Bryan DeNeve, SVP, Finance & CFO

Sorry, the last part of that question is relative to fixed cost…?

Roger Mortimer, CI Investments

Yeah, just dividend coverage and how investors think about the safety of the security to hedging overall.

Bryan DeNeve, SVP, Finance & CFO

Right. So when we look at 2017, you know, to cover 100 percent of our financial obligations we need to realize a price of $31 a megawatt hour on our remaining length of our merchant portfolio. When we look at where forwards are currently trading in Alberta at $45, basically as we sell forward at that price we're locking in a coverage that's well above 100 percent. Now, having said that, we also look very carefully at what forwards are trading at and what our view of fundamental prices are. So if we believe the $45 is significantly below where we think fundamentals should go, that's an additional consideration in us locking in that length. When we turn to 2018 it's the same concept, the only difference being as we see the carbon tax increase the price we need to realize to hit the 100 percent coverage goes up. So on our length in 2018 we need to realize a $40 to $41 price to reach that 100 percent coverage, including the dividend growth we've announced. But today where we see forwards is at $57, so $16 to $17 above that level we need for the 100 percent coverage. So, again, as we sell forward 2018 we're locking in well above that 100 percent coverage of our financial obligations.

Roger Mortimer, CI Investments

Sorry. So, Bryan, do you mean that you will move to hedge up completely that amount over time?

Bryan DeNeve, SVP, Finance & CFO

Yes, subject to again, our view of the fundamentals for 2018 versus where the forward prices are. Certainly our view is that at $57 that's in a range we would continue to sell forward 2018. And, as we've done in the past, as we approach the year in question liquidity will increase and we'll slowly hedge up and lock in close to 100 percent of our baseload position.

Matthew Akman, Scotiabank

Yeah, sorry, I have the mic, maybe I'll go. Matthew Akman from Scotiabank. There is a chart in the report or the presentation that showed the expected mix of generation going forward and it didn't look like you had gas-fired power growing at all really through the piece and I'm wondering if that means you expect all the, any of the co-gen plants that were all slated by the oil sands guys to be cancelled or whether that was something else.

Mark Zimmerman, SVP, Corporate Development & Commercial Services

Mark Zimmerman here. No. I think on that chart what we tried to do as an illustrative example was show how the coal was going to step down over time, two-thirds times three of wind renewables coming in, and then that gas piece. But we didn't add onto that—and so by default the gas piece is a very small bar in that chart. What we did factor in, is how much other changing dynamics you may have both in accelerated retirements or additional requirements for peaking for grid stability, et cetera, to be factored in on that gas wedge as well. So I think as we look at that fact longer term we absolutely expected a change and we would expect that current gas piece that I have indicated in there is actually going to grow over time.

Matthew Akman, Scotiabank

Maybe just to follow-up, this is a bigger-picture question I guess probably for Brian but it relates to your corporate strategy and I think today's presentation was more about the impacts of the Alberta policy change and your current plans as announced previously but when a government takes the vast majority of your assets out of service by the date certain that's earlier than you thought, it must give rise to bigger-picture strategic questions and I'm just wondering if it's too early to talk about how this will change your corporate strategy in terms of geographic focus, for example, or fuel focus, or if you've given that some at least preliminary thought, and recognizing that it's early days in that process.

Brian Vaasjo, President & CEO

Thank you Matthew for the question. Although we make it clear that our strategy hasn't changed or our value proposition hasn't changed, that isn't without some very considerable thought. When we look at starting with sort of your latter question first and the question around does it change the fuel mix that you're looking. Absolutely we are looking at solar and we're looking at wind and in terms of natural gas looking at it entirely from the perspective as how does it, regardless of the jurisdiction how does it complement the growing renewables profile in virtually every market. And so when we look at natural gas, as I was commenting on Genesee 4, it's not just here, let's just throw another chunk of megawatts into the system. How does it actually look and how will it operate in 2035 and 2045 and how will it complement the renewables that are there? We would absolutely expect our portfolio, if you look out over 15 years we would expect that, you know, it would be at least two-thirds renewables. You know, very, very significant growth in renewables given those are the kinds of opportunities that will be in front of us in Alberta but also throughout North America. If you look at the map that Mark put up, there's a little bit of natural gas but there's an awful lot of renewables. So our view of where we're going to go from a fuel mix standpoint is absolutely towards the renewable and much of that from a fully-contracted perspective.

To get to sort of the first part of your question, when you look at Alberta and you say, well, does that impact on your view as to whether or not you would like to continue to be a significant builder in that province. So as we look at it, and that's where the principles of compensation is very important. For a government to make a policy decision, and it's happened to us here in Ontario, it's happened to us in British Columbia, where governments have made decisions that have been very, I'll call it rapid, and significantly impacted on potentially value of assets, the question is how does the government make good on that. And so for us, again, I wasn't saying because the market is good we're going to continue, we need to understand that if there are future significant shifts in policy that we would be viewed in the same way and we would be adequately compensated. So, so long as there is a component of, and fair compensation has many different perspectives but as long as we can stand back and say that we've been fairly dealt with or reasonably dealt with we would see that as a market where we would want to continue to invest.

Now, more broadly, as Mark was saying, certainly we see all things being equal, and certainly some of these issues coming out, we see Alberta to be an excellent place to invest and would be seeing very, very significant investments there. I think I shared with you one or two investor days ago when the overall profile of what's being built in North America and therefore the pool of what we could do or we could see in terms of growth expectations was reducing, we did look at, as a company, what could we do, what would make sense, should we go international, should we get into natural gas distribution, are there other elements similar to our business that we should get into? And our answer was no. And probably absent some, this event in terms of the Alberta situation where all of a sudden there seems to be significant more growth, probably over the course of the next year and next 18 months we certainly would have been relooking at our strategy and saying, can we deliver shareholder value, sufficient shareholder value over the medium term given the nature of the opportunities that are in front of us? Alberta is actually, again, assuming that it sorts out appropriately, has actually been very beneficial in supporting our existing strategy.

Ben Pham, BMO Capital Markets

Ben Pham, BMO Capital Markets. Just with your commentary about two-thirds renewable long term, I'm just wondering, one of your slides on the free cash flow differences between your peer group, how you plan to compete in that market going forward, I mean are you considering maybe revisiting significant corporate restructuring with the spin-out of your renewable assets could compete better in that marketplace?

Mark Zimmerman, SVP, Corporate Development & Commercial Services

Just for clarity on my part, from a cost of capital perspective relative to many of the competitors? I think Bryan, and he'll probably give some detail on it, but I think the way I look at it is very high level. Bryan has indicated given our current cash flow and the dividend, sustaining capital, and other commitments we have, we're still left with internally-generated cash available for reinvestment of between $150 million to $200 million as we move forward, plus growing debt capacity, so I would view our ability is around the $400 million in the near term to reinvest on an annual basis, which, interestingly enough, the charts that I was showing with $2 billion probably required we'd be hoping to secure 25 percent of that. But I think we can do that before we even need to consider accessing the capital market. Beyond that, I think as the capital markets get comfortable with this we should see an improvement in our cost of capital, one would think, given the attributes that Bryan's reviewed here. I don't know, Bryan, if you want to—

Bryan DeNeve, SVP, Finance & CFO

No, I don't have anything to add.

Ben Pham, BMO Capital Markets

What about a spin-out?

Bryan DeNeve, SVP, Finance & CFO

Well, we've looked at that previously and certainly our strategy, both business and financial strategy, is predicated on the concept of maintaining a stable and growing dividend, but also providing upside from the lift in power prices in particular in Alberta. So spinning out the contracted assets into a separate entity doesn't fit. That kind of goes against that strategy. So we would certainly keep them together and, from what we've seen, the performance of yieldcos in the U.S. and what's happened so would see a lot of benefit to pursuing that.

Ben Pham, BMO Capital Markets

Maybe just a quick follow up on your maintenance plans a little bit differently maybe with Genesee 1 and 2 with the truncated life and you've been, you know, every two years, clockwork, maintaining those plants, just going forward maybe is there probably a case to maybe just move towards a three- to four-year cycle, for example?

Darcy Trufyn, SVP, Operations, Engineering & Construction

Well, good question. So absolutely we'll be revisiting all of this. Nothing is cast in stone and if we see advantages or reasons for changing our practices we would do so and adjust accordingly. I'd just note that a lot of our improvements have come through using our grey matter and not spending green money. So, that shouldn't change regardless.

Brian Vaasjo, President & CEO

Just maybe could I add on that? I mean an important thing to understand is that the environment that we're going into, what is the most optimal way to utilize your assets, and if you think of a coal plant certainly, if you have a shorter life it will have some implication for maintenance closer to the end of that life. But, for example, the last year or this past year we've increased the efficiency of Genesee 3 by 3 percent and we expect we can get it to 5 percent. We expect we can do the same thing with Genesee 1 and 2. So you think why put in the time if you're relatively short lived, well, the fact of the matter is it dramatically reduces your carbon exposure equivalently plus your costs are down into your utilization. And if you're going into a market that's going to be more volatile than the market is today, you want your plants to operate real well. I think in a strategy of let's just let them kind of fall apart over time I think you end up with unplanned outages, you end up with very significant cost events. Like in the market we're going into you probably need your plants to operate even better. So, again long-term maintainance, there may be some implications, but those plants we need to operate real, really well, reliably and at their capacities.

Peter Furlan, Hamblin Watsa Investment Counsel

Peter Furlan from HWIC. Based on that chart on the wall there, the carbon tax changes the merit order such that certain coal units may not be dispatched in the given hour and I'm wondering what operational impact that has for you guys given that coal units are designed to be base-load and yet I'm wondering if that change in merit order may cause some to go up and some to go down on a given hour and also what financial impact that will have, assuming you have that capacity utilization impact for your coals.

Brian Vaasjo, President & CEO

So, just broadly speaking, a lot of the change in dispatch order won't necessarily impact on our plants, just simply because of where there are, but you're seeing some plants now that are actually going through the phenomena that you are referring to, which is being dispatched up and down more driven by price and other characteristics, and you would expect that to happen potentially even more as Mark's price curve showed, your variable costs actually increase, which means there's more incentive to be off at particular times and more incentive to not operate. So, again, we'll see some market adjustments. But it is not good for a coal plant to be ramping up and down. It just—they're not made for it. You can, to some degree, ramp up and down levels of capacity above minimum stable generation but to actual be ramping them more significantly up and down is not a good thing for coal plants.

Bryan DeNeve, SVP, Finance & CFO

Just to add to what Brian said, there isn't a lot of combined cycle facilities in the merit order in Alberta, so certainly you're going to see a chunk of the coal continue to operate baseload, and that's going to be the coal with the lowest intensity, Keephills 3 and Genesee 3 given they're super critical. So the units that you're going to see cycling more are the older sub-critical units that are less efficient. Certainly with Sundance C, and we have the PPA on that, that would be units that we could see cycling a lot more. Fortunately for us, we have fixed payments under the PPA so any cost implications will go back on the owner of that facility.

Linda Ezergailis, TD Securities

Linda Ezergailis, TD Securities. Some of the slides I haven't seen any mention of biomass and how it might—sorry. Your presentation is largely silent on biomass and I'm just wondering have you had discussions with the Alberta government as to whether there is a role for biomass in the province and whether it be treated as part of the renewable mix with zero deemed carbon emissions or would it even be a competitive option in the other part of the mix with gas.

Brian Vaasjo, President & CEO

So biomass in Alberta is an interesting question. So certainly in earlier government comments you've seen some reference to biomass and it does, it definitely has potential. Even without any special incentive around biomass the fact that it's technically treated as being low or no emissions because of its, as long as it's waste, it certainly has the right attributes.

The issue about biomass in Alberta is that if you took all the biomass you could maybe replace one coal plant. It's just, just the capacity for biomass isn't that significant in the province. Is it going to be a big mover going forward? No. It'll be more something that may be at some point beneficial to one or other of the plants.

Robert Kwan, RBC Capital Markets

Robert Kwan, RBC. When you look at the chart that you've got on dividend coverage, and maybe the answer is $40 a megawatt is just completely out of the question in 2018. Thinking about capital allocation though, if that kind of level of pricing were to unfold you'd be at 100 percent payout and so how do you think about raising the dividend with that potential being out there versus maybe just de-levering as you think about all growth opportunities where your cost of capital is right now and it very well may be a cost of capital shootout amongst a lot of different players (inaudible) generation.

Brian Vaasjo, President & CEO

So I'll let Bryan answer the first part of the question after I answer the back part of the question.

One of the things is, is that, you know, our approach is, our strategy as it relates to growth is on the renewable side and on the build side, and cost of capital within a certain range gets lost in terms of the new build. So we don't see that overall when you put things together that we are at a disadvantage as it relates to building new facilities, whether they be in Alberta or BC or anywhere else. We think that some of our relationships and our ability to build at what is demonstrated lower cost, significantly offsets what might be a capital cost or a cost of capital consideration.

So maybe, Bryan?

Bryan DeNeve, SVP, Finance & CFO

Just in terms of 2018, if I understand the question Robert, is could we see prices coming in the low $40s, and certainly that would reduce the discretionary capital that we would have. That may have been a possibility before this announcement and the new carbon tax but with the—2018 is when it comes into full effect and with that $10 to $15 megawatt hour lift, if anything we expect we may see some early retirements than we otherwise would have. And that'll put up the pressure again on it.

As we move forward to 2018 we'll be locking in at that price, mid-$50s, $57, and certainly we'll see how that proceeds, but at this point see that price dropping below the $50s is very unlikely with the new carbon tax.

Robert Kwan, RBC Capital Markets

With the carbon tax differential is in that $10 to $15 as you were citing. We're down to $20 right now. So you, kind of without either decommissioning or some significant load growth that would put you into the mid-$30s.

Bryan DeNeve, SVP, Finance & CFO

Again, we're selling power at $57 right now in 2018.

Robert Kwan, RBC Capital Markets

And that $57 amount is the gross price?

Bryan DeNeve, Senior Vice President, Finance & CFO

That's the current forward prices Alberta that is trading at.

Robert Kwan, RBC Capital Markets

Like the gross and then you'd have the net (inaudible)...

Bryan DeNeve, Senior Vice President, Finance & CFO

That's right. Yeah.

Robert Kwan, RBC Capital Markets

Just one last question. If you look at that $2 billion number on net book value, is that the net book value today or is that the net book value in 2030 and then is that a present value?

Bryan DeNeve, Senior Vice President, Finance & CFO

That would be the net book value today.

Robert Kwan, RBC Capital Markets

Okay. Do you have an estimate as to what that number would be in 2030?

Bryan DeNeve, Senior Vice President, Finance & CFO

Not at hand.

Manash Goswami, First Asset

Hi. Manash Goswami, First Asset. Mark, on slide 24 you talked about 10 to 12 gigawatts of capacity, 80 sites, just curious is there actually that many sites available left to build that many wind farms? I thought maybe some of the sites have already been taken. So just curious your thoughts on that. And then maybe speak a little bit about transmission. Where would these sites be? Because I think a lot of them had been built-out, but I could be wrong.

Mark Zimmerman, SVP, Corporate Development & Commercial Services

No, you're absolutely quite right. So we are obviously out there assessing and trying to secure the best sites that we see out there. I think a lot of the build-out actually is going to be where the wind resource resides, obviously. That's going to be southern Alberta, that's going to be kind of south central Alberta around our Halkirk facility. As it relates to the number of sites itself, this has been kind of what we've seen historically and with current technology. We'd also expect as we move over time that maybe we see an expansion of the overall sites itself, so cut the number down but a much higher generating capability. I think you're quite right, as you start moving through time though as well you will need to see a reinforcement of the transmission grid in some places in order to handle this much more intermittent generation that we'll see.

I don't know, technology wise, Darcy, on the wind side?

Darcy Trufyn, Senior Vice President, Operations, Engineering & Construction

Well, we're certainly moving to larger units, but your questions are valid. There are only so many sites and there will be transmission upgrades if this all proceeds as planned. But there's also a question of things like storage and how that is, and that could change as well the number of sites. So size, definitely moving upwards, 3 megawatt type machines now are very much the norm, so there are ways to get to those numbers. And this is the assumption here is that it's, I think, just wind, and so there's other renewable opportunities in solar and others, so there are other things, biomass could be, so that's just illustrative right now.

Dominique Barker, CIBC Asset Management

Well actually it just touches a little bit on what you were—I was going to ask, the $30 billion investment that you guys see in new renewables over the next, I'm not sure if it's five years or ten years, if that includes transmission. And it sounds like it doesn't. Do you have an estimate of what the cost would be to Albertans?

Mark Zimmerman, SVP, Corporate Development & Commercial Services

Yeah, so, no, I don't have a personal estimate of that. The $30 billion was more in reference to both the renewables and the gas replacements, but I think, as already been touched on, depending upon ultimately the site and the timing, the mix of that is going to dictate the overall plan. I would expect as things unfold here we're going to see the new transmission plants coming out in terms of what infrastructure is required in order to support the grid and from that we'll have a better sense of what the cost would be.

Brian Vaasjo, President & CEO

Oh, I was just going to comment. One of the things that's sort of buried in the details of the proposal or the government position and so on is a part of the next phase of discussions is for them to come back with a sense of the stability of the grid and the overall reliability. Part of that will involve planning the grid, understanding a little bit more what it means not only with the reduction of coal but the increase of renewables. So I would, although nobody has said this, I would expect that there would be some sense of cost coming out with that.

Dominique Barker, CIBC Asset Management

Okay. And then just on the strategy side, and I think Paul Lechem kind of asked and Matt also followed up, just in terms of the new investments, it sounds like you would go ahead with G4, you're going to be making a decision in Q1. You said that Alberta is still a good place to invest, you said that market fundamentals continue to be there. I'm just wondering if you would proceed with that project before you receive compensation for your coal plants. I just want to clear—it's not clear to me.

Brian Vaasjo, President & CEO

So I think what I said is—so, firstly, maybe just to be very clear on a few issues, so the market fundamentals remain very solid and from that perspective that would make it, given a view of supply and demand, and part of it we're just talking about, the

power price and so on and so forth, but the fact of the matter is just when Genesee 4 is to come into service at its earliest point you're retiring almost 1,000 megawatts off the grid or have retired at least 1,000 megawatts off the grid. So some of those fundamentals certainly are there and, again, depending on other supply/demand issues, that may continue to be a good time to or a good decision to proceed with Genesee 4 in terms of construction. But what ends up being outstanding, if you've assumed that you understand the supply and demand balance enough, what remains outstanding is what I could call political risk. And the measure of political risk is very consistent with, in my mind, the level of compensation. And what we've messaged to the government very early is it's not just the cost to a company, it ends up being very much an issue of investor confidence in Alberta, and not just extending to us. So, for example, we provided them with the information that I think our top six investors also have investments in 126 other Alberta entities so you can't really carve off something really disastrous happening to the coal companies and it not having implications on whether Alberta is a good environment to invest in. So there's the element of your reaction as investors as to whether it's reasonable compensation at the end of the day. presumably it would have a ripple effect into your other investments.

The other issue is, as we pointed out a number of times, we're a major investor in the Alberta market, and if we and our investors are not comfortable with that market going forward, that is an issue for them. We have, right now, the only natural gas plant that is planned to be put into place. The others have either been pushed off or have died on the vine or whatever. Again, much of that had been because of supply/demand balance considerations. If we don't build, I'm not sure who's going to build to fill that 1,000 megawatt gap, or whatever gaps there may be at the time. So it's important to them that investor confidence, both from a company perspective and from a broader investor perspective, is maintained through their compensation. Now, will we know what will be compensation when that decision comes? Depending on the nature and breadth of principles we may or may not be able to move ahead with that decision. But I don't believe—in that timeframe we will know the amount or we'll know precisely how we'd be receiving that compensation.

Dominique Barker, CIBC Asset Management

So why would you proceed with a decision in Q1? Like what—is there a reason that it has to happen in Q1? Why wouldn't you just wait?

Brian Vaasjo, President & CEO

Well, Q1—so, sorry, that's actually an excellent question. So Q1 is a contractual date with Mitsubishi in terms of the project moving forward on the existing timeframe. If we pass that date then we lose our manufacturing slot and that pushes us way out. So that's what drives. So we have to make a decision that date, and that date may be to proceed or it may be to defer longer. So that's where that decision is. So it is a decision we have to make one way or the other.

Aram Fuchs, Fertilemind Capital

Aram Fuchs, Fertilemind Capital. I was wondering if you can talk, ah, I was surprised that CCS was not mentioned at all. Is that considered viable over the 15-, 20-year time period? Or is the oil market too volatile to work with an enhanced oil recovery system?

Brian Vaasjo, President & CEO

So I think it was identified on Mark's slide and we've had quite a history on carbon capture and storage and, in fact, if you're going to do carbon capture and storage anywhere in North America, Alberta is probably the best place, for a number of reasons. The issue is as we look forward will the environment be there whereby we can actually get funds to assist in the relatively high cost associated with it. One of the things that is very, I'll say unfortunate around how the regulations are coming out is carbon capture and storage usually left a residual. So, any of the proposals that were taking place a few years ago was actually bringing the emissions down to a natural gas equivalency. That won't work under the existing, under what the government is proposing. They're saying no emissions from coal. So the intensity doesn't matter, it just can't be from coal. So that actually is a significant impediment today in view of the carbon capture and storage projects that had been there historically.

Aram Fuchs, Fertilemind Capital

And then you referenced the U.S. yieldcos and how they were effectively purchasing everything like a drunken sailor and now many of them are, you know, sobering up, and I was just wondering if you looked at them as a possible M&A target, because of course they're, what they're trading at is, the IRRs are much richer than any new construction in solar or wind or anything.

Mark Zimmerman, SVP, Corporate Development & Commercial Services

Yeah, I would observe that we share your perspective that I think we have seen an abatement somewhat of many strategics out there being very competitive and pricing to perfection acquisitions. We have not seen it yet, a significant reduction in transaction prices, but as we see more and more product coming out of the marketplace we would think that there shouldn't actually be a price adjustment coming through.

As it relates to specifically the yieldcos and such, I'd offer, I guess, a couple observations on that. We would want to make sure that anything we're looking at from an M&A perspective compares favourably to what we have on a greenfield/brownfield perspective, and that's going to be both on returns as well as timing from an accretion perspective, but in addition we want to make sure that the portfolio has some relationship to the core competencies and geographies that we find ourselves in right now.

So I don't know at this juncture whether we would want to just run out and do a big one but to the extent, as things continue to evolve and we see where things are settling out, that is something that we remain attentive to and factor that in relative to the other options we have available for us at that time.

Aram Fuchs, Fertilemind Capital

Just one last question on compensation. As you mentioned, that's a key variable and I was surprised that the government didn't include some type of formula with the initial announcement. So can you talk about—have they offered you a schedule on when this decision will be made so we can look at it and model it from there?

Brian Vaasjo, President & CEO

So they haven't been very specific in terms of timing. I can tell you our decision on Genesee 4 weighs heavily on their schedule, whether you'll see a schedule that actually reflects that or not needs to be seen. I would be amazed if there wasn't a tremendous amount of progress by the end of the first quarter and there's something the matter if it isn't all wound up by mid-year. Like it's not, I mean there's a number of technical issues around grid and so on that need to be resolved but in terms of, say, a direction in terms of quantum of compensation and approach for companies like ourselves, I'd be amazed if we didn't have a good idea into the second quarter. And hopefully in the first quarter.

Evan Hughes, Picton Mahoney Asset Management

Evan Hughes with Picton Mahoney Asset Management asking another question on compensation. I imagine it will be a negotiation, a bid ask spread between yourselves and the government; to what degree does perhaps a precedent play a role? I've just begun on a very top level to read the Supreme Court ruling with regards to the AUC deeming that they weren't required to pay compensation for stranded costs, can you help us perhaps understand what role that precedent may play in the negotiation?

Brian Vaasjo, President & CEO

So I don't believe the government has in mind they need to be paying compensation to avoid a legal outcome. I mean certainly, I mean companies like us and others would certainly be looking at legal recourse, assuming that there is no or woefully inadequate compensation, but I think what they have in mind is what degree of fairness, because they utilize that word quite often is what's fair to companies such as ourselves but they're also looking at, what would maintain investor confidence in Alberta and what would keep people like ourselves and TransAlta and ATCO continuing to be active market participants. So I think that's more what's driving their consideration of compensation as opposed to some degree of a legal threat.

Andrew Kuske, Credit Suisse

Historically the Alberta markets seemed very consolidated and now that there's a huge new build opportunity what stops irrational capacity additions from new entrants from outside the big four, the traditional players, new entrants coming into the market?

Brian Vaasjo, President & CEO

So we would expect there'll be a number of new entrants coming into the market. I think, as we've said historically, we believe that there needs to be more people in the market to actually improve, I'll call it, the health of the market. So we would expect that there will be new entrants. We think that certainly when you look at the amount of build, $30 billion over 15 years, it's very attractive. One of the elements around that is though that to a degree they will be merchant players, given that, taking the approach of the REC standards, even if you're going to build a wind farm you will be taking merchant power risk in the province.

Andrew Kuske, Credit Suisse

I guess what I'm asking is what stops them from being irrational.

Brian Vaasjo, President & CEO

Oh. From irrational? Well, so, first of all, any wind coming in or any renewables will be governed by a bidding process. So that automatically takes care of that. As the market moves forward you'll be looking at smaller chunks of generation. Like if you look at 2030 or 2035, you'll have smaller peakers, more responsive generation going into the market, so even if you had an irrational player, although, they would be looking at how to manage their costs and their portfolio at that point in time so there's stuff in there that would certainly drive them to not be irrational, but even at that if somebody makes a mistake and builds 150 megawatts or 100 megawatts out of step, it's not the same as somebody building 1,000 megawatts. So a lot smaller pieces.

Mark Zimmerman, SVP, Corporate Development & Commercial Services

And I do have to wonder if there's a natural corrective element in here as well in that we're not seeing from the Alberta government the offering of very long-term take-or-pay type contracts on the back of which the capital markets were very comfortable throwing a lot of highly levered capital at these opportunities and so I think, to reiterate Brian's point, given it's more of a REC concept with a merchant element to it, I would think the capital markets themselves will be instilling some rational behaviour before allocating capital to these ventures.

Paul Lechem, CIBC World Markets

Sorry to keep on coming back to this issue of compensation, but I will. Further to some of the other questions that have been asked, it seems to me that the moment you make the FID, a positive FID on Genesee 4 you lose a lot of leverage. So my questions are a few. Like what is the cost to you if you let your slot with Mitsubishi go? Is there some sunk cost that you lose? And, can you talk about it, number one.

Number two, will you be seeking more than just a soft assurance from the government? Like can there be some legislation around, if they do the same thing on gas 20 years from now that you'll get compensation? It would seem to me that you'd want to try and get some assurance beyond just verbal. And certainly what are you looking for in terms of hurdle rates on any new facility you build? It seems to me that geopolitical risk is going up a whole lot in Alberta. You know, you've talked about historically what your hurdle rates are on contracted facilities and non-contracted so can you talk about your return expectations?

And, lastly, would you see a lifetime on those gas facilities as 45 years, in that range that you historically talked about, and is that the way you would structure the financials on those facilities?

Brian Vaasjo, President & CEO

So, starting with the last question first, from a gas perspective, we would typically look at a gas facility today at being 30 years. We're doing a significant amount of modelling right now looking at what 2030 to 2040 looks like and what 2040 and beyond looks like, because that's the only way—we need to understand how anything we build would get dispatched in the future and what that environment looks like. So we're doing an awful lot of work trying to figure that out. And that will drive what would be the potential life of a facility, when might it reach either, well, economic obsolescence. So certainly you're not looking at a 45-year life. You're looking at something closer to 30 years.

Now in terms of when we're looking at compensation and is there a way to kind of lock the government into future considerations or future positions on that, I think technically the answer has always been no, ei ther through law or legislation or regulation. The most you can get is soft comfort where they say, gee, very supportive of you building natural gas, it's the right thing to do, et cetera, et cetera, but that was actually the answer to coal. I mean the government was absolutely delighted that we were building coal in the province, because at the time you had $10 natural gas prices. It was effectively reducing the cost of power in the province. So, and we play that back and different time, different government, and I think going forward you'd get the same answer. I really don't think from a legislative perspective or a legal perspective you can necessarily bind future governments. So I think it, when we look at sort of the discount rate perspective, we set basically in the third quarter, we adjusted our floors on discount rates, and we would look at, at the time we're making the Genesee 4 decision, to what degree do we add something to that floor, to our hurdle rate to consider potentially additional risk that we might be seeing in the Alberta market. Not just in terms of the market functioning and political risk, but there's also you're going to have a dramatic shift in what the market looks like. How many hours are at zero and how many—there's going to be a very dynamic shift in the way our market functions from a price setting perspective. So there's a lot of things to be considered.

So, to move it on, first of all, as you know, we negotiated those arrangements with the ability to keep moving things along, so there's a modest cost increase if we move it out. So it's not huge. The issue though is whether or not, if we're not moving it forward because of political uncertainty it may not be a question of moving it forward, it may be a question of not terminating the project altogether. Again, if we believe that there's substantial political risk it's not prudent to make that kind of an investment. And the financial exposure is relatively small. It's been a joint venture thus far with ENMAX so I think all-in between us it's maybe $20 million. So not a large dollar amount.

Jeremy Rosenfield, Industrial Alliance

Jeremy Rosenfield, Industrial Alliance. Just taking into account everything that we've talked about here so far, is there an incentive to move towards developing smaller scale natural gas fired power plants and also more peaking facilities rather than trying to make big assumptions in terms of political risk and hurdle rates and things that you don't necessarily have great visibility on at this point in time and so moving essentially away from large-scale investments and rather towards smaller scale investments that potentially could be lower risk and on a risk-adjusted basis might be better investment.

Brian Vaasjo, President & CEO

I think regardless of what might be an individual's view as to what they'd like to build, I think the market's going to move in that direction in any event. Like you will never see a 1,000 megawatt, in my view you'll never see a 1,000 megawatt unit ever built in the province again. And the only reason why something like Genesee 4 makes sense is because it's almost like a peaker. But, again, magnitude of investment and of course we have a partner, so that mitigates some of that. But you're quite right; the size of natural gas investments in the province will naturally go to being smaller over time. And of course that reduces risk of build in a particular period.

Evan Hughes, Picton Mahoney Asset Management

Yeah, I'll just ask a follow up on the carbon intensity. I think during the presentation made mention that Shepard might be this clean gas plant on the margin that the government is planning on basing the tax off of. Can you give us like a ballpark range of what the carbon intensity per megawatt hour of that theoretical, either Shepard or the theoretical plant setting the tax would be?

Bryan DeNeve, SVP, Finance & CFO

Yeah. So basically Shepard has a GHG intensity of about 0.38 tonnes per megawatt hour, so if you convert that into, at a $30 a tonne, you're looking at approximately $11 to $12 a megawatt hour. And then conversely of course the coal ranges from 0.9 to 1.2, depending on its vintage, so there you're looking at anywhere from $27 to $35 a megawatt hour. Now the compliance obligation is the delta between that and that was the $20 a megawatt hour I'd shown on the graph.

Randy Mah, Senior Manager, Investor Relations

Any other questions?
Okay. I'll turn it over to Brian for closing comments.

Brian Vaasjo, President & CEO

Thank you, Randy, and thank you all for taking the time today, both here and those who are wired in.

We are going through some uncertainty with some of the changes around the carbon legislation in the province. One of the things that's, I think, also important to consider was a significant issue for us was whether or not we were expecting there'd be a federal pancaking of legislation on top of it, which would be another risk. We're pretty comfortable from things we kind of understand that this probably is, or a high likelihood, there wouldn't be any other further carbon action at either a federal level or, a federal pressure for Alberta to do more as it relates to the coal front.

In terms of the carbon issues themselves, we'll certainly keep the market informed in a timely way and hopefully, as we have here, in as full a way as we can, and share with you our analysis and information. We do have some significant decisions to be made in front of us and certainly some longer-term decisions to be made as well, but thus far I've got to say we're pretty comfortable in the direction that we see things going with, a big question mark around compensation. The market continues to be and should be a very robust market worthy of investment and certainly the level of opportunities is there but, again, we in no way shape or form would want to put your capital at risk or undue risk where there isn't an appropriate return. So we're very, very mindful of that on an ongoing basis and we're very hopeful that things will work out, that Alberta will continue to be an excellent market for us to invest in. And, as I say, indications are that should continue but, again, we'll see over the next number of months where things settle out.

So thank you very much for joining us this morning and listening to the Capital Power story and where we are going both in terms of Alberta but also in terms of our views on our cash flows and certainly, importantly, where we are going in terms of dividend increases over the next three years. So thank you very much and I think lunch is being served. Thank you.
