PRESENTATION

RANDY MAH:

Good morning, everyone. My name is Randy Mah, I'm the Senior Manager of Investor Relations here at Capital Power. Welcome to Capital Power's fourth annual investor day event. This event is also being webcast from our website, so I would like to welcome those people listening on the webcast.

We have a full agenda this morning, with numerous presentations, including more details on our expansion plans in Alberta that we announced earlier today.

Before we begin, let me cover off the standard disclaimer regarding forward-looking information. Certain information presented this morning and the responses to questions, contain forward-looking information. The forward-looking information is provided for the purpose of providing information about Management's current expectations and the plans relating to the future. Please refer to the forward-looking information disclaimer at the end of the presentation, as well as our disclosure documents filed on SEDAR for further discussion on the material factors and risks that could cause actual results to differ.

Let me now introduce the following members of the executive team that are here today: We have Brian Vaasjo, President and CEO; Darcy Trufyn, Senior VP: Operations, Engineering and Construction; Bryan DeNeve, Senior VP: Corporate Development and Commercial; and Stuart Lee, Senior VP: Finance and CFO.

This morning we'll be covering various areas of our business. Brian will start off with an overview of Capital Power and how we are delivering on our strategy, Darcy will review the operational performance, Bryan DeNeve will cover our merchant markets and the portfolio optimization segment of the business, and at approximately ten o'clock we'll take a fifteen minute break.

After the break, Brian will provide a business development update. Darcy will then discuss the various development projects, Stuart will provide a finance overview and finally, Brian will conclude with a summary and outline our 2013 corporate priorities.

As we're covering a fair amount of information during these presentations, we'll hold the Q&A session until the very end, for anything that wasn't covered. And finally, at approximately 11:45 – 12:00 hopefully you guys can join us for a buffet lunch with the executive team.

Okay, over to Brian to start us off.

BRIAN VAASJO:

Thank you very much, Randy, and good morning everybody. Welcome to Capital Power's fourth annual Investor Day. I'd like to thank you for joining us this morning and showing your continued interest in Capital Power. This morning we released some very exciting news for Capital Power and we'll be elaborating on that as we go through the day.

But first, since we were here last year, there's been some changes to our executive team. According to a longer term plan, we distributed the responsibilities of our planning and information technology executive role among the executive team. An executive who would have been here over the last few years, Jim Oosterbaan, had resigned this fall to head up NGX. In consultation with this executive group, we divided Jim's operating and commodity management roles between Darcy Trufyn and Bryan DeNeve, respectively.

Certainly this reduced the cost of our executive dramatically, but it also created some tremendous alignment among functions. Kate Chisholm, our Senior Vice President and External Relations, now has all stakeholder functions, so a terrific alignment there. Bryan DeNeve is heading up our commercial area, which includes Business Development, Corporate Development, Planning and Commodity Trading, so all of the commercial activities fall within Brian's jurisdiction.

Stuart's taken on the role for Information Technology and Analytics. And in a company of our size, those are typically functions that fall under a CFO. And to Darcy Trufyn, we've added Operations to Engineering and Construction, so you can see as you go across each of the executive roles, a relatively tight package of responsibility. So as we have found as we've developed the executive roles, some very, very good alignment within their functions.

One question I've been asked fairly frequently is whether we have the capacity to absorb a 30% reduction in executives, and certainly the answer is yes. We have been going through a process of simplifying and streamlining our business. The sale of our interests in Capital Power Income L.P. and the BC small hydro assets, have had a significant impact on the availability of our executive.

Also the significant efforts in establishing Capital Power over the last four years and selling Capital Power Income L.P., are behind us. In the long run, this is the right number of executives for Capital Power and don't really see it changing in the foreseeable future.

The message I'm proud to continue to deliver is that our strategy remains the same and our corporate strengths continue to be the pillars supporting our strategy and our vision, to be one of North America's most respected, reliable and competitive power producers.

It's true that since we were here last year, the near-term outlook for our target merchant markets has weakened, but these periods were considered in the development of our strategy four years ago. However, I can assure you that we don't mindlessly retain our strategy from year to year. As management first and then the board, we aggressively challenge our strategy from a broad strategic standpoint, from a market standpoint, from a financial standpoint, from a risk standpoint, and of course from an investor standpoint. We continue to come back to the conclusion that our strategy is the right strategy for Capital Power.

Since last year, the near-term outlook for the Northeast and Alberta markets has softened. A combination of natural gas prices, slow growth in the US and the continued delay in retiring uneconomic generation sustained the over-supply in the US Northeast markets. In Alberta, the announcement that Sundance 1 and 2 will come back online near the end of next year, has reduced the forward view of power prices for the next few years.

In response to that, we modestly repositioned our portfolio and we've also increased our contract length in Alberta. Alberta continues to be a very attractive merchant market. With increasing demand and the retirement of coal plants, there are great fundamentals that will result in both increasing prices and opportunities.

Capital Power's geographic footprint will remain the same. Certainly, with the announcement of building the Capital Power Energy Centre, we will maintain our focus on contracted build opportunities. For the last four years the cornerstone of Capital Power's ability to meet our fixed commitments and dividends through all cycles, is to maintain our broad base of contracted cash flow from credit-worthy counterparties.

This chart demonstrates that as we layer on the completion of the wind farms and the Shepard project, our contracted megawatts go from 43% to 48% of our portfolio. Operating margin improves dramatically more, from 37% today to 64% in 2015, as Bryan DeNeve will describe. This provides the stable cash flow base, while maintaining the significant upside associated with the commercial markets.

Our fleet continues to be modern, relatively young and well-maintained. The addition of the wind farms and the Shepard facility, will help maintain a low average life into the future. The plant additions will also add to the modern aspect of our fleet. The Shepard project is the most efficient combined cycle facility in Canada. It will eventually be surpassed by the efficiency we expect at the Capital Power Energy Centre.

We continue to maintain our technology focus. The successful sale of our small hydros has helped sharpen our operational focus. With the addition of Shepard and the wind farms, the percentage of our generation that is coal-based declines from 42% today to 37% in 2015, while natural gas goes from 49% to 54%. We expect this trend of growing natural gas and declining coal in our generation mix to continue. Our availability continues to be high, with a 2013 target of 93%. This is over a timeframe where our actual megawatt production is doubling.

We continue to have excellent access to capital markets. We are committed to our investment grade credit rating and have a low debt-to-capital ratio to support. Other than through the DRIP, we have not raised common equity in 2012, nor do we expect to in 2013. EPCOR's position is now 29%, relative to the 72% after the Initial Public Offering in 2009.

Two of the great accomplishments for 2012 were the completion of the Quality Wind and Halkirk Wind projects on time and under budget. The divestiture of our small hydros helped sharpen our technology focus. And of course, the agreement to join ENMAX in the construction and ownership of the Shepard project.

Lastly, the Capital Power Energy Centre: The Centre will deliver efficient natural gas generation as need dictates in the latter part of this decade in Alberta. The Shepard Energy Centre we will now jointly own with ENMAX. It is an 800 megawatt (MW) combined cycle natural gas power plant, which is approximately 50% complete. It is situated in Calgary and should commence operations in the first quarter of 2015.

Capital Power has also entered into a 20 year tolling agreement with ENMAX, where we will receive fixed capacity payments and costs will flow through to ENMAX. For the first three years, 75% of our position will be contracted, which will drop to 50% for the balance of the 20 years. The combination of the facility, the tolling arrangements and the sale of Halkirk will yield an IRR that is above our blended minimum target of 10%. The cash flow and earnings per share are expected to be modestly accretive over the first five years and much more accretive thereafter.

ENMAX has also entered into agreements to buy power from Capital Power in 2013, 2014 and 2015, which Bryan DeNeve will elaborate on in a few moments. Overall it is an excellent arrangement for Capital Power. It's a terrific asset in our home market;

more than half contracted and some near-term sales of our power length in the Alberta market.

When we look beyond the completion of Shepard, with the growing power demand and the closure of coal plants in Alberta, there is certainly a need for new generation, and certainly before the end of this decade. The Capital Power Energy Centre can meet that demand. Working with GE, the Energy Centre will have the latest technology, which will be the most efficient combined cycle plant in the Alberta market. In addition to GE, we are considering other partners for the project.

We have been in the process of assessing two attractive sites, which have significant benefits associated with existing infrastructure.

Bringing the latest gas turbine technology to Alberta is consistent with our history of employing leading technology, bringing super-critical coal technology to Alberta and North America, LMS100 peaking technology to Alberta and Canada, participating with ENMAX in the Shepard project, and the future Capital Power Energy Centre. This means we have the best fleet of generation assets in what we consider to be the best market in North America. So how does this leading technology actually translate into value?

It gives Capital Power the best peaking responsiveness, the best coal reliability, the lowest environmental impact and lowest cost, and the most competitive natural gas combined cycle facility.

There's been a tremendous amount of change in our asset portfolio over the last four years. We have reduced our footprint and our range of technologies. We have divested our small interests so we could focus on significant investments. We have also almost tripled our megawatts from almost 1,400 megawatts, to slightly over 4,000 by early 2015.

In a few minutes Bryan DeNeve will discuss our track record with these investments. Although still early in the life of these investments, he'll demonstrate that as a group, they are doing well and if the North American, or the Northeast power market had recovered consistent with the forward curves at the time, our investments would be doing extremely well.

As we look to 2013 and beyond, how do we achieve our corporate priorities and vision? First we continue to focus on developing what we believe will be competitive advantages; people, knowing our markets and the development and construction of generation facilities, improve our efficiency and effectiveness through thoughtful programs, some of which are multi-year. We have achieved for 2013 a reduction in core sustaining maintenance capital of $16 million, and expenses of $20 million in our existing business, before adding the wind farms. Darcy will describe for you what we are doing in the comprehensive reliability area.

On the growth side, complete our wind farms, participate in the Shepard project and continue the development of the power generation projects in our target market.

DARCY TRUFYN:
Oh, good morning, and thank you, Brian. So today I'll cover operations from a 2012 perspective and then discuss some of the things that we're working on in Operations to improve our cost-effectiveness and performance.

I would note from the outset that any activities that we pursue to reduce costs, will not be at the expense of our assets and further, although I'm new in my role, I just want to say that I've been intimately involved with the preparation of our Operations budgets for 2013 and all their metrics and KPIs and I accept ownership of those numbers.

So just looking at this chart, this shows our availability over the last two years and into 2013, with our targets. It clearly shows that we are running our fleet in the low 90s. This is due in part to the young-aged fleet that Brian was referring to, but also, it does reflect on our maintenance practices; they're solid. All we're trying to do now is to make them better.

You'll note also that the US fleet has a lower availability and certainly we believe there's an opportunity there, as we roll out our reliability program. The slide also shows our safety performance – this is called TRIF – the note at the bottom is Total Recordable Incident Frequency – it's how we measure ourselves. We're tracking it very well and the key difference here, a change for Capital Power, is as of 2011, we started to incorporate our major contractors and then in 2012 all contractors on sites so not only does it capture our own performance and safety, but everyone working on our plant sites.

So in 2011 we began on a journey of improvement and it began with collecting data and then benchmarking ourselves. It's a very arduous task. It's not something we're just starting today; it's been something that's been worked on, as I said, since 2011.

We went to third parties, we looked out at the market, we selected Solomon to use for benchmarking, and Solomon looks at the big picture. And a company called IDCON was selected for the continuous improvement aspects. This was done at all our plants. I note that Solomon has something like 90 coal plants in their database and upwards of 130 gas plants, so it really gave us a good picture of us with our peers.

IDCON, they actually get right down into the details of how we operate and they look at everything from work practices, procedures, organizational structure, etc, so they get right down and they also benchmarked us. So these are really good ways of seeing where we are, and I'll be talking about this later in my presentation.

So this slide lists some of the main elements we've been working on at each of our plants. I've just listed a few of the key ones. The actions and improvements are different for the different types of plants and they're obviously dependent very much on the commercial structure, or market mission, as we would call it here, at these plants.

In North Carolina we've had some challenges with fuel and ash and we're working on them. We've also had some high O&M costs. There are a number of initiatives we're working on. I've just come back from North Carolina; I feel very positive that we're making significant improvements and 2013 will look to be much better.

New England, at the plant level we can't control the market pricing, but what we can do is control our costs and our performance. We've had some significant forced outages and so reducing our forced outages is certainly an area of focus in improving our bottom line as well on cost.

Island Generation, our focus is all about reliability and that plant, from that perspective, is doing very well, and then secondary, it's our cost. The opportunities at Genesee are much more on the cost side, but we're also looking longer term at things like additional revenue from ash sales.

I haven't listed all the other plants here, but I just note for example, that on CBEC, it's all about availability to ensure that we can back-stop our Alberta portfolio.

This slide, I've listed here three plants as examples where we are seeing differences now in terms of our controllable costs, and we are capturing lower numbers going into 2013, which we believe does show that we are headed in the right direction. So we expect to see this type of performance in all our fleet as we move out our programs.

So one of our key initiatives – and Brian touched on it briefly – that we believe will add significant value over the long term, is our Reliability Program. A key gain from this, certainly in the US, is a reduction of our forced outages. Currently we average upwards of 4% downtime due to forced outages, and they can come at quite a cost to the company. Eliminating all these forced outages is a visionary goal and certainly something we'd like to achieve. But realistically we do believe we can at least cut the forced outages in half.

So through this program we intend to standardize our best practices between plants. Historically the plants have operated somewhat independent and now we're moving forward to standardization. It's somewhat similar to something that I spoke in the past of, from an engineering perspective, that we did over the last couple of years, and again, it starts showing benefits as we execute. But the Reliability Program ultimately, it gets down to just being proactive, not reactive, and that's where the savings come. And we expect that over a five year period, that we will generate approximately a cumulative of about $25 million in EBIT and thereafter contribute with the existing fleet, approximately $20 million annually, as compared to today.

This is just a brief commentary on our wind farms, but we do have an existing wind farm at Kingsbridge and it does enjoy a very high rate of reliability and availability and we've used this plant as a template for how we are establishing operations for both our new plants at Quality and at Halkirk, and as well in our soon-to-be new plant at Port Dover & Nanticoke. And one of the key aspects is that we have our O&M with Vestas fully aligned with us commercially on performance and all our owner requirements.

Brian spoke about a reorganization with the executive. Well, that reorganization has also been applied to the entire Operations group and we believe that will drive, and is driving, efficiency and more importantly effectiveness. Brian noted that I look after engineering – from now all engineering – and that in itself will pay big dividends over time; it allows us to move people from the different groups to better apply their expertise in an effective efficient manner. And I see some real benefits as we go through 2013 in that, as this organization evolves.

The slide lists some examples of effectiveness; I'll just comment on the first one that says outages. Typical plants are gas ones; they don't have the infrastructure that Genesee has and it's difficult for them when they are only doing an outage every two odd years – a major outage – to plan and prepare properly for that outage. These outages need to be pulled off in a very short time and there's no room for error. We've now structured ourselves such that we can take the expertise from our Genesee operation, at no cost to the company, but take the people that really know outages at Genesee – we do them every year – and take that expertise and provide that as support and assistance to our other plants. And that's just one example of this reorg, what it's going to accomplish.

I mentioned at the start that we've proceeded with benchmarking of all our plants, using Solomon. They do track a number of very key metrics and they did tell us how we compare against our peers. The other one – IDCON – when they get into the details, they really do tell you what you're doing right and where you need to improve. And with IDCON it's all about continuous improvement that willl show results over the successive years. From all of this information we've prepared our programs and improvement and reliability, and we are implementing it on a priority basis, where we can get the biggest bang for the buck.

This slide talks about some of the improvements that we made last year. This is a couple of examples of improvements made last year in 2012. At Genesee we did complete the upgrade to the G2 unit to get it up to 400 MW. Historically, just to comment that both Genesee 1 and 2 have achieved upward of 5% higher availability than what is required in the PPA, and the added cost for this high availability has been more than offset by the additional revenue. Going forward, this is something that we certainly need to revisit to ensure we continue to benefit from the higher availability.

Some of you are aware that our outage in October on G3 was extended – our planned outage. The reason for that extension – it did come at a cost – but the reason was because of issues found on our high energy piping. As part of our preventative maintenance program, we do look at a certain percentage of high energy piping on each planned outage. This time we did discover one very serious issue with a weld and it resulted in further checks being done to other welds. The other checks didn't uncover as serious an issue, but they did uncover other minor issues. All of this had to be repaired and made right before we brought the unit back online. And although it was a cost to the company, we believe that this proactive approach has avoided what would have been a huge future cost for the company, because it would have ultimately resulted in an unplanned outage.

The second point on this slide, it talks about CBEC. For those that have been – I know many of you have been at previous investor days – certainly in the early days of CBEC, we did have our challenges with availability, but as you can see, we've made significant improvement on the availability of the two LMS units. This is one asset that we will continue to push to get as close to 100% as possible. It has significant advantages for the company.

This slide here does list all our planned outages for both 2013 and 2014. You'll note that for 2013 the significant outage at Genesee is unit 1, so we have one planned for 2013 only.

So in summary, we think we're on the right track; we've spent considerable effort over the past couple of years benchmarking ourselves; looking at how we are and how we compare with others, and we've looked not at our strengths, but our weaknesses and we've put in place now programs that we believe will address that. We're addressing our cost structure. We believe that this approach will prove beneficial and are confident that you will see substantial cost improvements in the months and years to come. Thank you very much.

BRYAN DENEVE:
Good morning. As Brian mentioned, my name's Bryan DeNeve, Senior Vice President Corporate Development and Commercial. So I'm going to start off this morning speaking to our merchant markets that we operate in in portfolio optimization.

So the two merchant markets in which we own assets include the Alberta market and New England market, which is located in the US Northeast. In the Alberta market we have the Genesee 3 - 50% of Genesee 3 - which we own in joint venture with TransAlta, as well as Keephills 3. In addition, as Darcy just spoke to, we have the Clover Bar Energy Centre, which is 240 MW of peaking capacity with GE aero-derivative machines and we also have the recently completed Halkirk Wind Project, which is 150 MW of merchant wind supply. Finally we do have an interest in the Joffre cogeneration facility, which is located in central Alberta.

In the New England market, we have three combined cycle facilities that total almost 1,100 MW, so that includes the Rumford facility located in Maine, the Tiverton facility located in Rhode Island and the Bridgeport facility located in Connecticut. The balance of the Capital Power portfolio in the other markets are typically under long-term contracts, so our portfolio optimization from a merchant perspective are really in those two hubs of Alberta and New England.

So the way Capital Power approaches managing the commodity risk is, we do have one central merchant group – our Commodity Portfolio Management group, as we refer to them – located in the city of Calgary. That group - there's one central trading desk – manages the exposure for both the New England and Alberta market. And we believe it's important to have all those assets as part of one desk, both for just risk oversight, but also to be able to optimize all the various commodity positions, especially with natural gas, which is a North American commodity.

Capital Power is one of the largest participants in the Alberta wholesale market and a very large presence in the New England market.

So in terms of the commodity group, the objectives are really twofold; the first one is to manage our commodity exposure, so that consists of our length off our merchant assets on the electricity side, but also, we have short positions of course, buying natural gas for our gas-fired facilities. But it also includes the emission offsets that we acquire and trade in order to meet our environmental obligations on our thermal facilities.

So in addition to managing the risk exposure, we also look to optimize the value of those assets in terms of how we operate them real time in both the New England and Alberta market, but also how we conduct forward trading on the term desk around those assets.

Finally, the commodity group also is involved in strategic portfolio management, so this is where they work very closely with the business development folks in terms of looking at long-term strategies in both the Alberta and New England markets. And the recently announced Shepard facility is an excellent example of that. So that's a case where we had both the business development side working very closely with our Commodity Group in terms of structuring that deal, and looking at how we should be structuring agreements around dispatch and how that facility will fit into our overall long-term portfolio management strategy in Alberta.

And a recent addition to our merchant group is the origination, so as some of you recall, previously as part of EPCOR, the organization exited the retail market in Alberta. However, one of the things that we think is important is to maintain relationships and contacts with large industrial customers and look to enter commercial arrangements to sell long-term power to those companies.

We have a long-standing relationship with some large industrials on our Sundance C Power Purchase Arrangement with companies such as Dow, West Fraser, Alberta Newsprint and also Millar Western.

So I'd like to turn to the Alberta market and sort of what we see on a go forward basis. So we expect the Alberta market will continue to provide strong pricing signals for the addition of new capacity and also to continue to demonstrate strong demand growth. So starting out with the graph on the left, as you can see, historically we've seen spark spreads in the $40 to $50/megawatt hour range over the past couple of years. And that spark spread of $40 to $50 is consistent with the type of margin that's required to build a new gas-fired facility in the province.

However, as you can see – and I'm just looking at the red line here – the spark spread is projected to decline over 2014 and 2015 and that's largely due to the return of TransAlta Sundance 1 and 2 units in the latter part of 2013, as well as then the addition of the Shepard Energy Centre in Q1 of 2015. However, when we look past that, what we see is a recovery in the spark spread in Alberta and that's driven by two factors: the first is strong load growth, so we're seeing load growth in the range of three to four percent in Alberta, which really translates into about 300 to 400 MW per year. But that's also augmented by the expected retirement of existing coal-fired facilities, which I'll speak to further in a moment.

But as you can see on the right hand graph, where we show really the amount of supply in the Alberta market, so this would include facilities that are currently under construction, such as the Shepard facility, and compares it to the increase in demand growth. And overlaying that is the projected reserve margin. So the reserve margin is really the amount of capacity you need to have over and above the peak demand, in order to cover planned and forced outages and to be able to provide sufficient ancillary services in the market. And as you can see in that 2017 to 2020 period, that reserve margin hits 20% and declines down to 10%.

Typically in a market, you look to have 15% to 20% reserve margin; that's kind of the optimal amount of supply. So the price signal in the Alberta market, based on this projection, is that beyond Shepard, there's going to be a need for new generation in that 2017 to 2020 time period. It could vary, however, on the pace of load growth, as well as the pace of retirements.

So I just wanted to speak in a little bit more detail around the anticipated retirement of existing coal-fired facilities in Alberta. So the federal government has recently announced the finalization of its rules around the period of time that existing coal-fired units will be allowed to operate, before having to physically reduce emissions to the level equivalent to a natural gas combined cycle facility, which is probably about half of their current emissions. To achieve that the facilities would require some form of carbon capture. Most likely right now post-combustion capture, capturing the CO_2.

When we look at the cost of that and as an organization, we spend quite a bit of time looking at alternative technologies for carbon capture. Although it is a technology that certainly will be economic at some time in the future, over the immediate time horizon we're talking about here, we don't expect it will be economic.

So as a result, what you'll see is that there's a significant amount of capacity that will be retired in Alberta at the end of 2019 – a little over 800 MW. And when you look further out, in the 2025 to 2029 period, you see almost 400 MW per year, and in 2029 there's a significant drop of 1,600 MW that will be retired from the Alberta market.

Now overlaying this is also the provincial regulations that require best available technology for NOx and SO2 controls on thermal facilities. So those rules really require the owners of existing coal-fired facilities to implement that technology by either the earlier of the end of the current PPA – Power Purchase Arrangement – or 40 years life. Now, they are allowed to go to 50 years using the emission credits, and 50 years would be consistent with the federal regulations. However, in terms of sulphur dioxide, the amount of emission credits that are available in the market is a very small pool. So it's only emission credits that have been generated by facilities currently located in the province.

So what that can mean is that we could see this retirement schedule accelerate, and in particular it's possible we would see that 800 MW in 2019 actually come off the system as early as 2017. In a similar manner, that block in the 2025 to 2029 region could also move forward if the owners don't find it economic to actually put in place physical controls such as FAGD or selective catalytic reduction for NOx on their existing plants.

So as I mentioned earlier we look at the Alberta market as one that will continue to provide strong pricing signals for the addition of new generation, and this is demonstrated by the history of construction under the deregulated market structure. So full deregulation took effect in Alberta at the start of 2001 and over the first 12 years, what we've seen is almost 6,000 MW that have been added to the market solely on the basis of deregulated pricing signals. And you can see the amount of megawatts year over year.

But what's even more interesting is if you look at the orange line, it tracks the reserve margin over that time period, and as I mentioned generally in a market, you look to have 15% to 20% reserve margin; that was the case when the market was regulated and it's what you want to achieve when the market's deregulated. And since 2005, we've seen that that reserve margin has fluctuated within a very narrow band between 15 and 20%, and that's really demonstrating the market's working and it's signalling the additional supply when needed.

When we look forward and we look at opportunities to invest in new generation in the province, this is one of the indicators we look at. So we don't just look at the price signal as what's happening today; it's our price projections in the future, but it also is a build-up of what we see happening to the supply and demand side.

So I'd like to speak a little bit about our commodity exposure in the Alberta market, so as I mentioned earlier, we have a number of coal-fired facilities and we have Clover Bar, which are what we refer to as merchant length in the Alberta market. And what we typically have in place is, we look to sell forward to reduce that merchant exposure as we move forward in time.

Now prior to the addition of Shepard, when we look at our current portfolio in Alberta, we had about 30% under fixed price contract for 2013, and then a very small percentage in 2014 and 2015. With the addition of the Shepard facility, which I'll speak to in a bit more detail later this morning, that percentage increases to 44% in 2013, 44% in 2014 and 17% in 2015. That bump-up is a result of entering those CFD contracts with ENMAX, which Brian alluded to earlier.

So as a result, in 2014, when you look at our contracted assets, which is about 50% of our portfolio, and then you look at our merchant links in Alberta, which is almost half contracted, our overall portfolio will be 75% contracted for the entire organization in that further 2014 year period.

The other important item I'd like to point out is, when you look at the graph below, that compares the price we've locked in our supply at, to current forward prices in Alberta. So that 44% is contracted at roughly $65/MWh, compared to current forward prices, which are running close to $60/MWh. Then in 2014 you can see we're slightly above current forward prices and we're also above in 2015, so that's value we're capturing over and above what the current forward markets are indicating.

So I'd like to turn to the Clover Bar Energy Centre for a moment and as Darcy mentioned, that facility, there's been tremendous progress been made in terms of its availability and that facility is absolutely critical that it does have availability as close to 100% as possible. So just as a quick background, the Clover Bar facility consists of an LM6000 and two LMS100s, which are GE aero-derivative technology, for a total of 240 MW.

These assets play a key role in managing our portfolio in the Alberta market. The first component is, it back-stops unexpected outages from our baseload fleet. So when you look at our coal-fired assets in the province, our largest single contingency is about 230 MW, so that would be if G3 goes down, we own half of it, we would lose 230 MW roughly on the system. The Clover Bar assets, which can ramp up and be available in under ten minutes, has a total capacity of 240 MW, so that's a key risk mitigation measure, because now we can use those facilities to back-stop our position when we have outages, as opposed to having to hold length on our baseload portfolio.

The aero-derivative technology can start and ramp to full load within ten minutes, and that allows it to provide spinning and supplemental reserve in the Alberta market and selling those ancillary services, typically generates a premium over selling just into the energy market.

And finally, with those facilities available, it does provide a more broad range for us to take trading strategies in the Alberta market. So given we have that real time optionality to dispatch those facilities, we're able to take more balanced positions on our portfolio, and as I mentioned earlier, not have to always keep length in the event of a forced outage.

So I'd just like to look over a bit of a longer period in terms of our captured prices for our Alberta fleet, and this graph demonstrates that very well. The orange line from Q4, 2009, shows the average realized price for our merchant facilities in the Alberta market. The blue line is the averaged spot price in the Alberta market. So there's really two things that you can see in this graph: the first one is the stability of the orange line. So as we manage our portfolio on a forward basis, we're able to create stability quarter over quarter, relative to where the Alberta spot market is settling.

But the other thing to notice is that that orange line, on average, is 20% higher than the average of the settled spot prices, so that's a premium our facilities are earning over the average spot price in the Alberta market, and that's a premium we believe we'll be able to sustain as we move forward.

So I'd like to turn now to the New England market, which is our second merchant market. So we continue to believe the New England market does have attractive long-term supply/demand dynamics. However, as Darcy mentioned, we have seen some collapse in spark spreads in the near term and that collapse is due to several reasons. One is falling natural gas prices, which tends to compress the spark spread, because those less efficient units which are higher than the stack, which utilize more gas than our combined cycle ones, basically the pool price that they bid in at it shrinks.

The other thing is, we've seen lower load growth in that market and the third item is, we've seen some supply come on sooner than we anticipated. One is the Clean Energy Facility in the New England market.

However, one of the things when we look forward is, we expect recovery in the spark spread and also capacity prices. Now the recovery in the capacity prices is going to be somewhat delayed and that is largely driven by the removal of the floor in the capacity price market in the 2017 period. And you can see that dip here on the picture.

But the benefit of removing the price floor is that it's going to drive out a lot of uneconomic generation that's currently in the New England market. These are older thermal facilities, oil-fired facilities, which are kept alive right now, simply because the floor on the capacity market is allowing them to cover their fixed O&M costs. We expect with that floor removed, you're going to see accelerated retirement of those facilities and that'll then result in the steady growth back in the capacity price as we move forward in time.

Long term, the need for natural gas-fired generation in New England, we see that as being beyond the 2020 period, so when you look at the graph on the right, which shows the supply stack versus the demand, you can see the reserve margin line, similar to what I spoke to for Alberta. It does drop below 20% in 2017, so that's similar to what we see in Alberta. However, one of the dynamics in the New England market is that they do have a renewable portfolio standard, so as renewables come online to meet that brings in some uneconomic generation. We also expect some growth in demand side response and some growth in imports. So that together is going to result in the need for new gas-fired generation to come on later than what we would see in the Alberta market. However we do expect we'll see the price recovery in that 2020 and beyond period.

So in terms of our merchant exposure in the New England market, we currently have in place a hedge on the Bridgeport facility, which continues on for 2013, so as a result, our merchant exposure is 50% hedged. We currently are fully merchant in 2014 and 2015, but our Commodity Portfolio Group is looking at those years and looking for opportunities to start locking in those margins. One of the things we have seen recently over the past couple of months is a strengthening in the pricing in the 2014-2015 period, which we'll be looking to take advantage of.

So I'd like to just turn to quickly our environmental commodities portfolio and the bulk of this really sits in the Alberta market, so in Alberta there's two drivers: we have what's referred to as a Specified Gas Emitters Regulation, which requires a reduction in greenhouse gas emissions or purchasing offsets for greenhouse gas emissions, of 12% for existing thermal facilities. So in terms of our coal-fired assets, we've acquired offsets that cover that exposure through to 2014, and one of the things is, we're able to acquire most of that portfolio at prices much lower than the $15 a tonne price under the Specified Gas Emitters, which is a fund you pay into if you don't buy the offsets in the market.

We looked to the US Northeast; we have obligations on the GHG side under the Regional Greenhouse Gas Initiative. Again, that's where our Commodity

Group does purchase and trade offsets in that market to manage that position.

And then finally, if we look further south and go to our North Carolina facilities, that's an area where under the Clean Air Interstate Rule, we do have obligations to also have offsets in regard to NOx and SO2 emissions, and again, our Commodity Group manages that exposure through purchasing those offsets in the market.

So, as a backdrop to our Commodity Group, we do have the middle and back office, which actually report up through Stuart Lee. The middle office is really the area where we track and measure the exposure on our commodity portfolio and making sure that we're staying within our corporate risk management guidelines and limits. The back office of course is where we do settle the transactions that come off the merchant side.

So the commodity portfolio risk policy establishes a framework for determining commodity risk limits based on our ability and willingness to take risk, and we use value at risk calculations so that we understand how much the exposure is in the various markets that we're in. Back testing is also done to recalibrate those value at risk parameters to ensure they reflect the current volatility in the markets.

So one of the initiatives that has been underway within Capital Power for the last year and a half, is the implementation of a new Energy Trading and Risk Management system. So this replaces our old system that we've had in place probably since the 1990s. The ETRM system allows us to track our position on a much more granular basis, on an hourly basis. But more importantly, it allows us to update and it provides reporting much more frequently on our position, and it also allows us to implement and utilize other products, such as options for managing the exposure on our merchant portfolio. So the ETRM system basically came into effect a month ago and has been working well.

So the last area I just want to touch on quickly was commercial value creation. So, when we look at our portfolio of assets, Darcy spoke to you on the operations side, we're looking to create value through better planning of outages, reducing costs, getting the right balance between costs and reliability. We create value as I just went through, on the commodities side, but a third area is commercial value creation through non-commodity opportunities. This is looking to optimize our long-term contracts, whether it's with the balancing pool on the Genesee 1 and 2 assets, or our off-take agreement with Progress Energy in North Carolina.

We go through a process where we set targets on an annual basis for value creation that is not anticipated in the budget process. And typically we set those targets around $4 million per year. Some examples of those opportunities that have come to fruition in the past is reductions in environmental costs, such as what we're doing to meet regulations around mercury reduction; increased capacity at Genesee 3, which Darcy had mentioned to you, which is a joint effort cross-function within the organization. Another example is looking at putting in place an agreement to provide black start capability at the Clover Bar Energy Centre.

We've exceeded these targets over the last three years and I would say probably about two thirds of those opportunities are ongoing value, so not just one-time effect, but value that's put in place and we'll be realizing on an ongoing basis.

So when we look at US Northeast to mid-Atlantic, we have the same level of activity in terms of trying to improve the value through commercial optimization. We have initiatives underway where we're looking at for example being able to utilize landfill gas at those facilities to create additional renewable energy credits that we then can sell and trade in the market. And for example on the North Carolina facilities, we're looking to enter long-term fuel supply agreements, which optimize the value of those assets as we move forward.

RANDY MAH
So we're about twenty minutes early, so what we're going to do is just continue on with Bryan's next presentation and take the break right after that. So if you want to refresh your coffees, there should be new coffee outside. Okay Bryan, if you want to continue on.

BRYAN DENEVE:
I was hoping I would get to have a muffin. Okay, so we'll now turn to covering the growth activities that we've been pursuing as an organization. So this is our favourite picture in the company, which is our target markets in North America, so as Brian mentioned, we're looking to maintain those markets. I don't see any changes at this time, or in the near future. Maintaining the focus on those target markets creates a discipline around our growth initiatives and also maintains the focus of the organization.And we also continue to believe that these target markets will provide sufficient opportunities to meet our strategic objectives without having to add new markets, which obviously can have quite a steep learning curve as you enter them.

So the Alberta and US Northeast markets, as I just went through, really are key what we call network hubs. They provide the opportunity to realize synergies, both in terms of optimization trading around the assets, but also optimization on the operations side. For example in the US Northeast, between the Rumford and Tiverton plants, which are sister facilities – same vintage, 7FA machines – we realize a lot of synergies operationally with those, in terms of being able to utilize common inventory and utilizing expertise across those plants.

Our contracting markets continue to be BC, Ontario and the US Southwest. I'll touch on a bit later two key development projects that continue to proceed in Ontario and two in the pipeline in the US Southwest.

So just to refresh our framework for growth: so we really look at it as making sure we zero in on those opportunities that fit very well with our overall corporate strategy. So that first screen of course is our target markets. We are very disciplined in making sure that as opportunities come through, only those that fit within the target markets, or if there's a multiple group of assets that the vast majority of those are located in our target markets.

As we move down into the circle, we then come to technology, and as Brian mentioned, we continue to focus on natural gas and coal-fired thermal facilities, and wind, and solar. And we've completed quite a lengthy process of tightening down our fleet through the divestiture of assets that don't fit that technology focus, and the most recent example is the divestiture of the Miller Creek and Brown Lake hydro facilities in BC.

So then once we get within the technology, we then have our financial criteria and our financial criteriaconsists of both target after-tax unlevered returns, which vary depending on the overall risk of the opportunity. But at a high level, we look to a fully long-term contracted asset, to exceed an 8% after-tax unlevered return, and for merchant opportunities exceed 11% after-tax unlevered return. We also have very clearly defined accretion targets, particularly over the first five years of the asset's life.

So, as we get down, the other two dimensions is merchant versus contracted and development versus acquisition. And as Brian mentioned, we are maintaining a 50/50 balance between merchant assets and long term contracted assets. I just want to emphasize again here that when we look forward to 2014, about half our EBITDA will be coming from the long-term contracted side of the house. Half will come from the merchant side, but through our Commodity Group through managing forward contracts, we probably have about half that merchant exposure locked in, at least for 2013 and 2014 and we'll continue to look to do that as we roll forward.

So touch on the Alberta market. As I mentioned earlier, we expect the need be on Shepard to be in the 2017 to 2020 timeframe. And the need for power is driven largely by strong load growth, but also expected retirements of existing facilities, which has become more certain with the federal legislation.

The two opportunities we're focused on right now is entering the JV partnership with ENMAX on the Shepard Energy Centre and a longer-term opportunity, the Capital Power Energy Centre, to meet that need in that 2017 to 2020 timeframe. So just turn to Shepard quickly – Brian covered most of this – there are two Mitsubishi G-class machines, each 240 MW and a 320 MW steam turbine for a total capacity of approximately 800 MW.

One of the things that the Shepard facility provides is, it's location outside of the city of Calgary; it actually has allocated lower line losses than other facilities in the province. So the facilities located in central Alberta, typically bear higher line loss costs because of their location. Shepard, because it's in the southern part of the province, bears lower line losses.

And actually one of the interesting things about this opportunity is, it provides us a hedge against how those line losses will change as we move forward in time. So line losses shift depending where load grows in the province, depending where transmission is located. We see Shepard as actually benefitting if there's higher line losses on assets located in central Alberta.

The project is approximately 50% complete – slightly ahead of schedule – and we're very confident it'll reach commercial operation by Q1, 2015. As Brian mentioned, the project is projected to exceed our target unlevered return of 10%, which is kind of a weighting between that 8% and 11% that I mentioned earlier, and we expect it to be accretive $0.05 to $0.10 over the first five years of operation.

So Shepard is a very good strategic fit for Capital Power. It's in a target region that's our largest networked hub. It fits very well with our existing fleet in the Alberta market, so we have a strong baseload fleet, we have the Clover Bar Energy Centre I mentioned, which is really the fast-start peaking facility, and in the early years, Shepard fits nicely in between those two.

The other element though to Shepard is, as you roll forward in time and we see that baseload coal start to retire in the Alberta market, because Shepard will have the lowest heat rate for standalone gas-fired facility, it wil really start filling in that baseload need in the province. So, the early years we see its capacity factor being sort of in the 60% to 70% range; that'll increase up to a high 80% range as it starts operating more consistently as a baseload facility.

So the other key strategic benefits with the arrangement with ENMAX is 50% of it is contracted back to ENMAX for 20 years, under a traditional tolling arrangement, And that tolling arrangement is priced at a level so that our returns do exceed our target returns for contracted assets.

In addition to being 50% contracted for 20 years, it's additionally 25% contracted for 2015 to 2017, and that's a period where, as I showed earlier, where we see lower prices in the Alberta market, so that really allows us to get through that period with stronger cash flows than we otherwise would if the facility was fully merchant.

And then a third piece, which is very critical to us, is the contract for differences that we're entering into with ENMAX, and this is where there's strong synergies between the companies. So ENMAX, they have a power purchase arrangement with the Battle River PPAs, and actually we sold that to them, probably about five years ago, and Battle River 3 and 4, the PPAs will be ending at the end of 2013. Now, between that period and 2015 when Shepard's online, ENMAX is going to be short-power, given their retail portfolio. So this has provided us an opportunity to fill that gap with length from our portfolio during that period, and that's why you see 300 MW in 2014.

So just in terms of roles and responsibilities, given the facility is well under construction, we would see ENMAX continuing to manage construction and actually operation after the unit becomes commercial. However, the management committee which will be in place, gives Capital Power the ability to contribute our knowledge and experience, and Darcy will speak to this in the next presentation. But we've constructed about $3 billion worth of assets in the Alberta market, so already we're starting to see some benefits of bringing our experience to that project. We also will have individuals that will be working as part of the construction management team.

So as part of the plan for financing the Shepard joint venture, we do plan to divest the Halkirk Wind facility. So the Halkirk project has just reached COD and actually has been generating very strongly over the past few days, I must say, so it's been operating close to 120 MW to 130 MW out of its 150 MW capacity. So we're also seeing that as anticipated, it's not as highly correlated with other wind generation in the province, which means it will capture a higher percentage of the average pool price than other wind facilities.

When we look at Halkirk, which is also a partially contracted facility with renewable energy credits sold to PG&E, so almost half of its cash flows are from a contracted base. But when we look at the merchant side we really are a price-taker, so strategically, to be able to manage that length in our portfolio, we don't have the opportunities that we will with the Shepard facility. So when we look at the prospect of being able to trade-off merchant wind megawatts for megawatts on a dispatchable combined cycle facility, we see this is a good trade-off for the organization.

So I just want to highlight the amount of shift that the joint venture with ENMAX will have on our mix of contracted and merchant cash flow in the organization. So as you move up and again, this is looking at the percentage of assets that are under a long-term contract, and the percentage assets that are in the merchant market. It doesn't reflect what we may have sold forward through our Commodity Group.

As we roll into 2014, we're basically at that 50/50 balance. And if we hadn't entered the joint venture agreement, what we would have seen happen is effectively, the merchant side would have continued to decline and that's largely the result of the contracted wind assets that we still have in the pipeline that'll be coming online. So at the end of 2013, we'll see Port Dover & Nanticoke; end of 2014 we'll see K2. So that's what's driving the higher percentage of contracted versus merchant mix, as well as some decline in the merchant revenues of course, in the 2015 period. But the arrangements on the Shepard facility, what that'll do is, it pushes the contracted percentage in 2015 from 58% to 64% and the merchant down from 42% to 36%. So as we look at that period of time, the amount of cash flow that we'll have under fixed pricing arrangements and the stability of our cash flow would be a lot stronger than it would be without the arrangement we've entered into on Shepard.

So I just want to speak about the Capital Power Energy Centre. So it will consist of a new gas-fired combined cycle facility in Alberta in that 2017 to 2020 timeframe. What we see here is a real opportunity to take advantage of GE's advancing technology on the combined cycle side. And the new gas turbine technology that GE's working on, brings a number of benefits, which is a very good fit for the Alberta market. It's faster starting than the older vintages; it has a much lower minimum stable generation, which means you can operate through the on-peak, off-peak periods and turn down the machine much further than you could with the older vintage of combined cycle technology. And it also will have the best heat rate out of all the combined cycles technology that's out there.

So strategically working with GE, we see it as a real opportunity to bring that new technology to bear in the Alberta market, which has, of course, a lot of hourly price volatility. And the other thing we think when we look at the opportunity is to bring to bear of course, also our construction experience in the Alberta market.

We do expect, as we move forward with this opportunity, we would likely do it with an equity partner and we are in discussion with several entities on that front. And we also have two very strong sites to locate this facility, which are well down the road of assessment.

So in terms of the BC market, we see limited wind opportunities in the near term. Obviously there's some concern over how much renewable should be brought into play in the province. We do expect that uncertainty will get resolved over the next couple of years, so we continue to work on developing wind sites we still own in the province; collecting wind data, and two in particular. We'll be very well-positioned to compete in the next request for renewable supply.

You probably also all heard about the opportunities on the LNG side in the province, and we're there looking at those opportunities very hard and we're looking to do it through a couple of avenues. One is leveraging our relationships with the First Nations. So when we look at the Quality Wind project, that is one where we are able to put in place long-term agreements with the McLeod Lake, the West Moberly and the Soto Nations. Those long-term agreements are really indicative of the type of arrangements that will help facilitate bringing more electricity into play in the province to serve the LNG needs.

So I'll turn to the US Southwest. In the US Southwest, we have seen lower load growth than anticipated. And the Renewable Portfolio Standards, which of course are very high in California, but also exist in the desert southwest, has resulted in the need being pushed out for supply. We also do see continued uncertainty around the market structure in California.

However, there are a couple of areas where there are opportunities in that market that we're pursuing. In the southern part of California, they continue to see strong load growth and we anticipate San Diego Gas and Electric, especially with the issues around the SONGS "[San Onofre Nuclear Generating Station]" nuclear unit, we'll be looking for new supply in the 2018 - 2020 period and we continue to work on development of a combined cycle site near the city of San Diego, that will provide an opportunity to develop that under a long term contract.

The other opportunity is the Sun Valley Energy Centre. So that's located about an hour west of Phoenix. That's a project we've had under development for about a year; it's 3,000 acres, which will accommodate an approximately 300 MW solar facility, but we also see it as a site that's very well-positioned for the development of gas-fired generation technology when needed. We're actively in the process of bidding into RFPs, looking for renewable supplies in the 2017 plus timeframe.

So I touched on the Southern California development opportunity. Just add a couple more elements; it would be up to an 800 MW combined cycle facility and we do expect the RFP will be coming out in the first half of 2013.

So just transferring to the east side of the continent. So in Ontario, we have heard that the FIT has been restarted, so that will create some opportunities in the near term, but we don't think they'll be very large, or there'll be a lot of megawatts that will be awarded. So our focus will be to continue to complete the development of the K2 wind project and Darcy will speak to where we're at on the construction of the Port Dover and Nanticoke project.

In terms of K2, that's a 270 MW wind project that we have a joint partnership with Samsung and Pattern. We just submitted our REA application for environmental approvals in November, so that was a significant milestone. That application will now get reviewed and we're hopeful we'll see a decision - a favourable decision – in Q1 of 2013. We'll be looking then to start construction on the project in the latter part of 2013, and to meet a COD of Q4, 2014.

K2 would be the fourth wind project in a pipeline that we've developed, starting with Quality and moving to Halkirk, and Port Dover & Nanticoke and then K2 will be the fourth of those, all of them providing very strong returns to the organization.

So, how have we been doing? When you look at the projects that we've completed and brought online – as I mentioned, it includes the four wind projects, the acquisition of the combined cycle facilities in New England and now recently the 50% joint venture on the Shepard asset. Also, since the formation of Capital Power, we completed the construction of Keephills 3 and the Clover Bar Energy Centre.

When you look at the wind projects and the assets in New England, basically 60% of that portfolio is contracted on a long-term basis. The expected unlevered returns based on our most recent projections, is that these projects will produce, after-tax, unlevered returns in the 8½ to 11½% range and the expected weighted unlevered return is 10.1%, which exceeds the weighted target return of 9.2%.

So we look more specifically at breaking it down. When we look at the EBITDA on the projects that have been added since the formation of Capital

Power, the US Northeast has underperformed; that's predominantly due to spark spreads being less than anticipated when we acquired those assets. That probably accounts for about three quarters of that shortfall, and then the balance is due to the implementation of the Connecticut tax and availability being slightly less than expected.

However, we're seeing on the Keephills 3 side much stronger performance than we expected, so power prices have been stronger in Alberta since that unit has come online than in our original business case and availability had been very good at the Keephills plant. So those two things together have resulted in that facility bringing in much higher returns than we originally expected.

When we look at Island Generation acquisition, it's pretty well on target and when we look at the Clover Bar Energy Centre, it is also meeting expectations from our original business case. I would like to point out, in the case of Clover Bar this is just looking at straight cash it receives through the sale of power into the market and through the sale of ancillary services to the AESO, but it doesn't take into account its overall portfolio benefit and risk reduction it provides for us as an organization, so that value of course, wouldn't be reflected in those bars.

You can see from an availability perspective, where we're far above target on Keephills and Island, US Northeast falling a little bit short. And Darcy spoke to where we are on Clover Bar – but as we look forward with Clover Bar, we do anticipate we'll actually be exceeding what was expected in the original business case.

So finally, when we look forward with the wind projects and that pipeline that has been developed and constructed, the four of them together does have quite a transformational effect on Capital Power. So at the end of the day, when we get all four completed and up and operating, we'll be seeing annual cash flow in the range of $165 to $175 million from those assets.

On a cash accretion basis, they're going to add accretion in the $1.05 to $1.10 range, and on an earnings per share basis, those four projects are going to add $0.40 in total, once we reach the 2015 period and they're fully operating.

Thank you.

RANDY MAH:
So we're a bit ahead of schedule, so what we're going to do is take a break and come back at 10:30, so we'll see you back here at that time.

[Recording paused 01:28:20 - 01:58:34]

DARCY TRUFYN:
Okay well, good morning again. So for the past three investor sessions, Brian Vaasjo and I have presented some of the things that we were doing to create our competitive advantage in new developments. We talked about creating tools and standardizing processes and building up an organization that was different and is different from others. Today I believe you'll see the results of that investment.

So Quality Wind, it was our first new development secured under the Capital Power logo. Much time and effort was spent in the front-end - I've talked about this in the past - the work that we did in the front end of the project, doing value engineering, constructability, risk analysis, all with the goal of improving the asset and optimizing the project costs. When construction actually began two years ago, we were very optimistic that in spite of it being a very challenging environment there that we would have a successful outcome.

As the work got under way at Quality Wind, we began working on the front end of Halkirk. Today's announcement does take the shine a little bit off the accomplishments of Halkirk, but still from a development perspective, it does really demonstrate our ability to successfully deliver projects.

This development on Halkirk, it initially began for us in a partnership with another developer, where the other partner was managing the engineering and construction. Once we acquired the total development, we made numerous changes to the design and execution strategy to help improve the economic returns of this asset. We also incorporated improvements and lessons learnt from our Quality Wind development. As a result, as we went into construction about this time last year, we were very optimistic that all of this front-end work would again help ensure a successful outcome.

Today I'll provide some details on the successful completion of both Quality Wind and Halkirk and I will also talk about our newest development, Port Dover & Nanticoke, and why we believe we will also achieve success on this development. Following my presentation will be a short video on Quality Wind.

So Quality Wind is located near Tumbler Ridge in northern BC and because of the short weather windows, this project was built over two seasons. Last year, you may recall, we completed all the civil work, including roads and foundations and this year the project focused on the substation and the turbine installation. And as the slide does highlight, it has been completed on time and under budget.

The project scope includes 79 Vestas 1.8 MW turbines. These are totalling 142 MW; it's a combination of V90 and V100s that we believe will help optimize the capacity. The scope also, on this project, includes 22 kms of high voltage transmission. We did achieve COD on November 8th and our forecast for our final cost is approximately 10% under our original budget.

Some of you, I believe, have visited the project during construction and know first-hand that the project was built in difficult terrain; we had lots of geotechnical uncertainties, the short construction seasons that I mentioned, and given its remote location, these all provided real challenges to our team and the constructors on the project. We were, as Capital Power, very much involved with the construction and execution of the project. We believe this management approach is important to ensure our assets are constructed to our standards.

We also don't just build to the lowest capital costs; we do look at lifecycle costs. A case in point, on Quality Wind, during the construction we were advised by Vestas of new lightning protection for the blades. We went through an analysis, did the business case and made the decision that this expenditure would have a good payback over the life of the asset and we went with that.

We also, on this project, spent additional money on the foundations to protect them, have better drainage. This is something that the EPC contractor didn't believe was necessary; we chose that because this is a long term asset for the company, that this was just good insurance to protect the asset.

Now, I know we've announced that Halkirk is an asset that we will be divesting, but I do want to talk about the project itself, because it really is a success story. As I noted, through the execution of Quality, we incorporated lessons learned, we embedded those into Halkirk and that provided us just another advantage going into the project. You may recall from last year's presentation, we began work on this in November. Our plan at the time was to construct some of the roads and foundations in early winter – and that would give us a good start in spring. Unfortunately we had some technical issues on the project and delayed the foundation work until late in spring, and then we were faced with some other challenges. So this project actually was built primarily in six months, through June to November, so quite an achievement and really does say something about all those involved with the project.

So this project has 83 V80 1.8 machines from Vestas; quite a different project than Quality, but it in itself, aside from schedule, it did have significant challenges. One of the challenges is that we were working with neighbours, so it's in farmland, so dealing with neighbours and making sure that we respect their property and don't impede them and things like cattle, etc, etc. These all were quite different from Quality Wind, but the crews were able to work very well with the neighbours. As it's noted here, this project did finish on COD December 1st of this year, that's 14 days ahead of our planned schedule, and it is slightly under budget; we're forecasting approximately a 3% under-run on the final cost.

So in addition, just to comment in addition to the notes there: we really do care about the communities, the places that we work in. The Quality Wind, with First Nations in community; here at Halkirk the same. You're going to see a video that really does highlight that at Quality Wind, but here at Halkirk we also were very successful in meeting the expectations of our neighbours and the community. We did a blade signing ceremony at both facilities. At Halkirk with a town that's something like 120, we had something close to 2,000 people in attendance to sign the blade and it really demonstrates that we walk the talk and that we do respect and work well with the communities that we are involved with.

So Port Dover & Nanticoke, it's our newest wind project; it's located very close to here, near Lake Erie in southern Ontario. This is a 105 MW wind farm; it's using the same Vestas V90 1.8s as we have at Quality. As most of you know, the REA on PD&N was almost a year late, but in spite of this delay, we've held our COD date to the last quarter of 2013. Over the delay period it has caused issues for us, but we've taken advantage as well on the delays, and worked again, very hard at looking at ways and means that we can find additional savings, better ways of building. So we've taken advantage of the delay and as a result, we are very optimistic that this will be very much the same success story for Capital Power.

An example of the front end work - the value of this: when we did Halkirk, we did make some major changes to the electrics at the substation. Through that we decided that it made sense to purchase a spare transformer that would be used for either Quality Wind or Halkirk as a back-stop, but we also looked at PD&N and decided that it made sense that even though it's slightly different in size, that if we standardize our transformer we would actually have three of the same in our fleet and that spare then could be used to back-stop any of our three developments.

But it also had an added advantage in that currently it's something like 18 months delivery on a transformer, so it's obviously on the critical path of any development. The fact that we're able to get out of the gate now on PD&N; we've started construction here in late September, but the transformers not on our critical path. We're using the spare; it's at the

OEM, sitting there; it will be delivered directly to PD&N in spring. It takes it off the critical path and then we can backfill it later on, once the transformer from PD&N is actually manufactured.

So that's sort of a value engineering, but it's making things work for you and so it's a tremendous savings. We would have otherwise had a six month delay on the PD&N project.

So just in summary: In addition to creating a very strong organization that's capable of executing just about any type of fuel plants, we have worked behind the scenes over the past three years building up our database, working hard in gas, working on solar, so that we believe that when Bryan comes to us with new opportunities, that regardless of the fuel type, we'll have the people and systems and tools to successfully deliver those projects.

So with that, we'll now go to the video and again, this video really focuses on the celebration – the blade signing – at Tumbler Ridge, with Quality Wind. And again, just you'll see the community and, I believe, how well they've received us, both in terms of the local community, but also First Nations. So thank you very much.

VIDEO PLAYS:
[2:11 – 2:17]

STUART LEE:
Alright, now that you have seen the commercial, I'll get into how it actually translates to the bottom line. Just talking about overall the financial strategy, I think consistent with Brian Vaasjo's earlier comments; 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 investment grade credit rating, well-spread debt maturities, ongoing financial flexibility in our capital structure, as well as a very stable and well-supported dividend with a disciplined growth strategy.

If you look at our overall leverage, we remain one of the lowest leveraged companies in our industry. Expected to finish the year at mid-30% and likewise, as we scroll forward to 2013 and the end of the year, we expect to maintain that low leverage. Over the longer term, our target continues to remain at 40% to 50% level, and believe that we have the capability of adding additional leverage and driving earnings through modest increased leverage, as our credit metrics support it.

And again, if you look at a lot of our peers in the 50% to 60% range, not a lot of that additional capacity.

Capital markets and financings: we talk about the fact that we've had good access to the public markets. I will comment and I will apologize upfront to a number of the sell-side analysts in the audience today, because we are in the market as we speak with the preferred share offering, so you will be restricted on publication, but to Randy's point earlier, there is a free lunch afterwards, so thanks for coming out.

The other public offering, we were in the market earlier this year, in February, with a $250 million medium-term note that was well-accepted in the marketplace.

On the equity side, no near-term expectations around primary offerings. We're well-positioned to finance the growth without any significant new commons. EPCOR obviously has been a seller of our stock and they've moved their position down at the time of the IPO with 71%, to currently in the 28% - 29% range, and they've been pretty clear that over time they do expect to sell down their position to zero.

And one of the benefits though from that is that we've seen increased liquidity in our stock and the fact that we were added to the TSX Composite Index last year, and the fact that our trading volumes have effectively doubled over the last two years. In light of the fact that EPCOR has continued to sell down, what was an effective poison pill by having them as a major shareholder has started to diminish and the Board did ask us that we address and look at that.

And so you'll have noted over the last couple of weeks we announced the fact that we had adopted a Shareholders Rights Plan. That will go forward to the shareholders to vote on at the AGM in April. I know there was some speculation we saw in the marketplace around what that might mean. Quite frankly, this wasn't in response to any activities we've seen. This was simply in response to ensuring that there's good governance in the organization and that in the event that there was a potential hostile, that we could act, and the company could act, on behalf of all shareholders and not specific shareholders in that type of action.

Similar to what we showed you last year, again very well spread out debt maturity profile, no near-term maturities through 2015 and as we look at the balance of the maturities, they remain very manageable and well spread out, so very little refinancing risk. I would note that earlier this year we did extend our credit facilities to five years. It's a $1.2 billion facility; close to a billion dollars remains available under those facilities, so great liquidity. In addition to that, we negotiated a $300 million accordion feature to it as well.

As we look at our development projects and our capex profile, fairly consistent with what we've seen with the addition of Shepard, and probably worth talking a little bit about how that stacks up. Obviously with PD&N coming up this year, the majority of the spend – about $250 million – will take place in 2013.

As we look at Shepard, the way that this is staged, we actually step in to a 25% interest with the announcement today, and an additional 25% interest in 2014, totalling the 50% interest, and that's why you see staggered funding requirements, with approximately $335 million next year and $470 million in 2014. And I'll talk in another couple of slides about expected financing associated with this growth capex.

On the sustaining capex side, Darcy talked a little bit before about our planned outages coming through 2013, reducing an uptick in overall spending. This past year Genesee 2 and Genesee 3 would have gone through major turnarounds. Next year Genesee 1 and Keephills 3 are expected to go through major turnarounds. The incremental spending is about $15 million of incremental spending on Bridgeport, which represents prepayment under the LTSA for the major outage scheduled for 2014 for Bridgeport, and that's the major step up there.

On the sustaining capex side, you'll note a decline in spending on sustaining capex. Again, a view of trying to tighten sustaining capex and some of the discretionary projects over the next year or two, as we see some dips in the overall pricing environment in our merchant markets. But to Darcy's earlier points, we have a track record of excellent maintenance on our plants and this in no way diminishes our goal, or our ability to deliver high availability.

The other capex line represents IT projects. Bryan mentioned the fact that we have recently completed our ETRM trading IT project, and in addition to that, a major project that's just been completed and will go live on January 1st, is a reinstall of our financial reporting system. When we were spun out by EPCOR, we effectively cloned their system. It wasn't necessarily applicable to our business on a generation only business, and so we've redesigned that system and a number of efficiencies will come out of that and cost reductions associated with that. But as we look forward to 2013 and beyond, we do think that that capex spend obviously comes down as we've completed certainly two of the major platforms in our IT strategy.

And then on the Genesee land expense we have had an ongoing expansion of our Genesee mined lands. We've been spending about $20 million a year over the last couple of years to expand the mine areas. You'll see that the capex spending steps down in 2013 to $9 million and as you go out to 2014 and beyond, that number drops to zero, so we've effectively accomplished what we wanted on the Genesee land mine extensions, and so you won't see that capex line item past 2013.

Not only are we conscientious of some of the near-term challenges based on where merchant prices have moved, and trying to pull back in some of the sustaining capex, but on the opex side as well, we have been very active in looking at some of the efficiencies we can drive in the business, and so maybe I can just talk about year-to-year some of the explanations behind some of the cost variances on the opex side.

If you look at the increase from 2010 to 2011, it really reflects the fact that we would have bought the Island Generation facility in late 2010, we would have bought the three New England assets in early 2011, and in addition to that, we would have brought Keephills 3 online in September of 2011. As we look at 2011 to 2012 and the drop, a lot of that reflects the divestiture of CPILP and the fact that we're to drive out costs associated with managing that enterprise, which was divested in late 2011.

And then as you look 2012 to 2013, Brian Vaasjo mentioned earlier, our expectations on the two additional wind farms is they add about $20 million in costs. We're effectively offsetting that, as well as inflation in salary adjustments, through cost efficiencies, and some of that is driven out by some of the IT projects, as well as cost efficiency projects that Darcy's initiated at the plants and across the organization.

On a cash flow basis one of the themes we try and impress on folks is just how stable and strong our cash flow is. This year we're targeting cash flow, FFO from operations, at $385 to $415 million, relatively consistent with last year. About a little over a third of that is discretionary cash flow that's being reinvested in the business, so if you look historically over the last three years and then now into 2013, approximately a third of our cash flow is going back to shareholders in the form of dividends and distributions. Between 25% and 35% is going into our existing assets in the form of sustaining capex and then the balance, generally speaking between 30% and 40%, is being reinvested in new assets. In addition to the wind projects that we're currently underway, obviously some of the new announcements, including Shepard, that we announced earlier today.

So one of the benefits and we talked about it and Brian Vaasjo's mentioned it; the fact that as part of our overall strategy, believe in maintaining that balance between contracted merchant assets, conscious decisions to reinvest in contracted assets like the wind projects that are coming online - Quality, Halkirk, PD&N and K2 – and those certainly add incremental cash flow through the 2013 to 2015 period.

The addition of Shepard, a benefit in the short term is the fact that we do end up with additional hedge positions in 2013, 2014 and 2015, and the fact is, as we come out in 2015, Bryan DeNeve had mentioned the fact that our contracted portion of our portfolio in fact increases, associated with this investment.

The other thing that's important to note is, you're not looking at a short-term stream of cash flow; we have one of the youngest fleets in North America; we continue to reinvest in this fleet and it continues to grow younger as the company matures, and it certainly has long-lived cash flow expectations, based on this reinvestment.

When we step back and take a look at our cash flow, one of the ways we measure it – and I'm not sure that the market fully appreciates it yet – but we look at both on a dividend yield as well as on adjusted funds from operation yield, and just to give a little bit of definition around this, adjusted funds from operation is funds from operation less maintenance capex. And so as we compare ourselves with the balance of our peer group, I think you'll find that our dividend yield at 5.7% is roughly in line with where the balance of the industry is.

But if you look at our AFFO yield, which is effectively the valuation relative to our cash flow, we would take the view that the market hasn't fully appreciated just the level and strength of our cash flow generation. And in particular, if you look at the orange space on these bars, it represents how much ability do you have to support your dividend and how much additional cash flow you're generating to reinvest in your business, and you'll note that within the peer group, we certainly are one of the stronger cash flow generators, above and beyond what I would view as a very sustainable and very solid dividend.

So obviously the announcement today, a lot of questions will be around how do you expect to fund a fairly substantive capex program over the next couple of years? We were very comfortable with the PD&N and K2 development projects and the fact that internally-generated funds would allow us to not issue equity or any early major incremental debt for those two projects.

As we look with the addition of Shepard, what you'll see is, as we look at the different sources and uses of cash, we would expect that at the mid-point our FFO next year, around about $400 million, we used the mid-point in this analysis. Proceeds from sale of assets would be the proceeds from Halkirk and I will say that the $340 million is an assumption at cost for illustrative purposes. Obviously our expectation is that we would hope to see a premium to that cost basis.

And so if you look at the remaining financing requirements for 2013, very manageable - $176 million. We would expect that a large portion of that could be satisfied through the pref market. We will look potentially at moving our DRIP program to a premium DRIP program, to raise a little bit of additional equity. Quite frankly, we don't think there's a lot of additional equity though that would be required for the Shepard project if we institute a premium DRIP program, and given the fact that a significant source of the funding will come through the Halkirk sale.

As we move through 2014, 2014 financing for Shepard will come from internally-generated cash flow, a modest amount of additional debt and equity if required, closer to the COD date. But again, if we implement a premium DRIP program, we'd expect that that equity component would be very small.

Bryan DeNeve covered a little bit about our hedge position earlier today; as we move to 2013 and 2014, 44% hedged. Then again, this is our baseload coal position in the province; it doesn't include gas assets and 17% in 2015. We've provided some sensitivities associated with that and I think you'll look at approximately about a $4 million EBITDA impact for a dollar price move. One of the things, let's make it really clear, is just around our expectations for a power pricing in the market next year. We've come out and underpinned our projections on a $58 power price and maybe just a walk through how we set pricing, so people understand our expectations of the marketplace.

Effectively when we go through the budget process which starts in September, we look at the forward prices, we put a pin in for our budget. At that point in time – beginning of September – the forward price is worth $58. We'll compare that with our fundamental price forecast. If it's within a reasonable range, we generally use the forward price as at that point in time.

If you've seen the range of estimates in the Alberta marketplace generally kind of coalescing around that $55 to $65 range, I think you could make strong arguments for either side of that range, quite frankly. A lot of it's going to depend on how reliable the Alberta fleet is next year, what type of weather patterns we see and what type of incremental demand. I would view, particularly if you look in line to where our forwards are at right now, we're probably a little bit on the conservative side of that, but do think that within that range $55 - $65 it would be pretty easy to support prices at either end, and likely we're a bit on the conservative side on our use of the forward at $58.

For New England, again we provide some price sensitivities around spark spread, as opposed to just dollars per megawatt hour, so based on a one dollar megawatt hour change, you see some sensitivities in the New England marketplace. Our expectations, if you look at mass hub on-peak in the mid-$11 range for next year; that's slightly below where 2012 is expected to settle. As Bryan DeNeve mentioned, we are seeing, particularly in the 2014 and 2015 period, some strengthening in some of the forwards on the spark spreads, but we have yet to see that in 2013.

I want to spend a couple of minutes just talking about the wind projects and both on how they'll be accounted for, as well as the expected economics associated with them. If you look at Halkirk, it's what we look at as a traditional long-term asset and how it'll be accounted for, so normal asset accounting with a depreciation impact. We do expect it to generate annual cash flow in the $22 million range and that's after financing costs. And the project's expected to be about $0.04 accretive to EPS in 2013.

For purposes of looking at it – and we expect that we will launch a process for the sale of this sometime later in Q1, with a sale sometime late in 2013 – so for purposes of our guidance, we have included Halkirk for the majority of 2013, but have taken it out for 2014.

Quality Wind, a little bit different story. As opposed to using traditional long-term asset accounting, you end up with a 25 year PPA and therefore require to use finance lease accounting. So as opposed to setting up a long-term asset and depreciating it, you end up setting up a long-term receivable. This project, again, has very strong cash flow accretion. It ends up with an annual cash flow of about $28 million, and that's after financing costs, and it's expected to be approximately 12 cents EPS accretive. And again, relative to Halkirk, its overall profile is flat on an earnings basis, based on the structure of the PPA, while as Halkirk with its merchant exposure, had a little bit of an obviously upward curve as you move through the later part of the decade.

Just looking at the overall financial outlook and comparing it 2013 to 2012, we obviously expect a full year operations form Quality Wind and Halkirk. EBITDA – Darcy talked a little bit about North Carolina; two things to look at on that our overall expectations for 2012 relative to 2013, relatively flat, and that's a fact that we do expect better operating performance from those assets, offset by the fact that that the renewable energy credit pricing that is set under the terms of the PPA, drops $3 million in 2013 and 14, and then steps back up from 2015 to 2021, to levels that we've previously seen under the contract. And so, between those two factors, expect to see fairly flat overall performance year to year.

Likewise in New England, we're expecting relatively comparable earnings 2012 to 2013. We would expect slightly higher availability at those facilities, as well as reduced maintenance offset partially by the fact that spark spreads are expected to be modestly weaker.

So just getting to financial targets again; I've talked about the fact that underlying our targets, and probably a bit on the conservative side, is a view of $58 per megawatt hour power pricing, which generates an expected EPS target of $1.20 to $1.40. Coming into this year, we had guidance of $1.50 to $1.70; that was again, based on forwards at the time in late 2011, which would have been at $74 per megawatt hour. Coming out in Q1, we did revise guidance down to be below the low-end of our range, based on the fact, as we sit here today, power prices are expected to settle somewhere in the mid- to upper-$60 range, so below our budgeted price at $74 coming into the year.

On both an FFO basis, as well as a cash flow per share, relatively consistent year-over-year and reflects the fact that offsetting some of the decline in pricing in Alberta, is the fact that we are bringing on some very good wind projects next year.

Taking all that financial information and reflecting back on how does it impact our credit rating metrics. Before I get into this specific metrics, I will comment on the fact that with the Shepard announcement, we have talked with both DBRS and S&P. You'll see their reports out at some point today; DBRS may already be out. They have no changes to our ratings associated with the Shepard project.

On the DBRS metrics they look at both FFO to debt, as well as an interest coverage as two of their core metrics. We are well beyond what they require to maintain a BBB rating and so I feel very comfortable in where we are with respect to that rating.

For S&P we have a BBB- rating. Their requirement on the FFO to debt is 15% to maintain that rating. Again, layering in Shepard, we expect to be well within that range and on the liquidity side, excellent liquidity and well beyond the 1.2 that they generally require for investment grade credit ratings.

I will comment on the fact: obviously we've always maintained that BBB is where we want to maintain our rating at. DBRS continues to have us there. S&P recently obviously downgraded us to a BBB-. We remain committed to being at that BBB level; we think that's the right risk profile for us as an organization as consistent with being a very stable dividend payer, and do expect, as we see Alberta power prices recover, that we will regain that. And in fact, layering in the Shepard project, coming out in 2015 with this asset and the additional contracted nature of it, we feel very comfortable that we'll get back to that rating within that timeframe.

Another thing that I want to touch on, just as around guidance; you know, we're obviously coming out with 2013 guidance, and maybe just to look back on how good has our guidance been over the last three years. Has it been on the mark, off the mark? And I would say on an annual basis, we have a fairly good track record of meeting the guidance we've provided. I commented on 2012; we expect to be modestly short of our guidance, given the fact that Alberta power prices are coming down below. But if you would overlay the actual power prices in Alberta, put it onto our sensitivities, I think we'd be right in line with our guidance. If you go back to 2010 and 2011, we've exceeded our annual guidance.

The one thing, if you look at analyst consensus on a quarterly basis, there is one consistent theme that I think emerges out of this, and that's the fact that Q2, we have consistently come in below where analysts had modelled us. And one of the things important to note is, Q2 will always be a quarter that we will likely have lower performance on a seasonally adjusted basis, simply because it's a shoulder season and we always take one of our major Genesee outages in that period. And so something important as we model out on a quarterly basis and reflect that in the quarterly estimates.

So just to wrap up, not much different story than you heard from me last year. We continue to deliver on a strong financial strategy, very consistent with what we mentioned when we came out on the IPO. We continue to strive to be a moderate risk and to manage our risk effectively. We maintain low leverage; we do think we have some additional capacity in our balance sheet over time as our credit metrics continue to improve, to take on some additional debt. We've remained very committed to our investment grade credit rating and will actively defend that rating.

And on the dividend, we have an extremely well-supported dividend; certainly no concerns at all around that and would expect that we're well-positioned over time to grow that dividend. And with that, I'll turn over to you, Brian.

BRIAN VAASJO:
Thanks, Stuart. So across this morning we've gone through a number of presentations and we've talked about 2013 and our expectations and our priorities. What I want to talk to you about now, is drawing those priorities together, summarizing them and these are priorities that we'll track with you as we go through the year and you can monitor as to how we're doing relative to those priorities.

So looking first at our operational targets, and certainly that's a priority for us each and every year, is to have very strong operating performance. And the lead indicator of that is our availability. And so for 2013 our target availability for the year is 93%. Next is our maintenance capital expenditures, which we are targeting $105 million, and as you saw from the chart that Stuart put up, when you take out the planned maintenance, that's a significant reduction in our core sustainable capital maintenance.

And I just want to assure you that in no way, shape or form are we risking our assets by reducing our maintenance costs. We're looking at ways and means in which we can spend those dollars more wisely; we're looking at ways and means in which there are costs that aren't necessary to expend. So again, under no circumstances when you see the reduced maintenance capital expenditures, can you expect that our equipment won't be as well-maintained. I can assure you that it is, and we'll be maintaining our operating stability and certainly our availability targets as we go forward.

Likewise, Stuart went through how we have,… at least numerically it looks flat, on our existing operations today there are some significant reductions in our maintenance and operating expenses. And likewise I can assure you that not only does that represent the continued proper maintenance of our assets, it also includes ensuring that we have the appropriate resources in place to manage our risks, from a regulatory standpoint, from a government standpoint, and certainly from a commercial standpoint. So those resources continue to be in place to manage the risks of the organization.

Moving to the growth side, we're looking to continue to deliver projects that meet or exceed our expectations. For 2013 this includes the completion of the Port Dover & Nanticoke project, and reaching the commencement of construction on the K2 project. We'll work very closely with ENMAX towards a successful continuation of that project for successful completion in 2015. And we'll update you again, quarterly, as we go through with those projects and how they are meeting our expectations and of course your expectations.

When we go to the financial targets, Stuart spoke to those at some length and I won't go through them again, but what I will say is that we will monitor where we are on those expectations and describe for you, on a quarterly basis, where we may or may not be meeting or exceeding those targets.

So in summary, Capital Power's strategy continues to be sound through the business cycle and positions us to deliver shareholder value. Much of the value comes from continually optimizing our existing assets, whether through our cost management, through revenue maximization or through risk reduction. The repositioning of our Alberta portfolio with the participation in Shepard, other elements around that transaction and the sale of Halkirk, are activities that represent the creation of tremendous value for Capital Power.

We have been and will continue to work hard to optimize the fleet and our costs. This is a thoughtful, disciplined work to reduce cost and risk at the same time. This has and will yield significant expenditure reductions through 2013 and beyond. Our results will continue to reflect the value we consistently capture through portfolio management activities, and Bryan demonstrated through his graph, that we have a very strong record of delivering value that is a 20% premium to what is the ultimate settled price in the Alberta market.

We will continue to track our record of delivering on wind and natural gas projects. Looking forward, our focus will be on contracted development projects in Canada and the US. With the Capital Power Energy Centre being merchant, we will need these developments to maintain that critical balance of contracted and merchant assets. The growth we have committed to, although significant, is readily financeable, in large measure through our commitment to maintain our investment grade credit rating.

2013 and the developments and directions we have addressed this morning, are consistent with our strategy and general approach to everything we do. A thoughtful, disciplined and transparent approach to maintaining and creating shareholder value.

Thank you.

RANDY MAH:
Okay, thanks Brian. We're ready to start the question and answer session. So for the benefit of those listening to the webcast, please use the microphone and please identify yourself before asking your question.

JUAN PLESSIS:
Thank you. Juan Plessis, Canaccord Genuity. Maybe I can start with the Shepard transaction. You talked about the 10% unlevered after-tax IRR and I believe – I just wanted to confirm – you include in there the loss of earnings and cash flow accretion associated with the Halkirk facility. I guess a better way to put this is, would it be fair to look at this as a 10% unlevered after-tax IRR on not only the capital spent for the Shepard plant, but in addition, the capital or the $340 million for Halkirk.

BRIAN VAASJO:
That's correct; that's an all-inclusive look of return when you take into consideration the project, the PPA and the sale of the Halkirk project. And that's assuming the sale of that project is at cost, not with any sort of a premium that we'd expect on it.

The one exception to that is that depending on how you may look at the PPAs, the 100, 300 and 100 – or pardon me, the contracts for differences in the earlier term – those are not in any way impacting on the overall rate of return of the combination of transactions. Those we did not put into that analysis.

JUAN PLESSIS:
Okay, thanks for that. And the $0.05 to $0.10 per share accretiveness of this acquisition, or this project, does that assume a theoretical equity issue consistent with your existing capital structure, your targeted capital structure?

STUART LEE:
So Juan, that's based on our actual expectations around obviously the sale of Halkirk and fairly nominal amounts of additional equity.

JUAN PLESSIS:
Okay, thank you.

LINDA EZERGAILIS
Linda Ezergailis, TD Securities. One of your competitors is looking at increasing direct physical long-term contracts with industrial and commercial customers, given some of the drop in liquidity in the forward markets in Alberta. Is that something that you're actively pursuing and what do you think it will take to get customers to sign on physically long term beyond ENMAX?

BRYAN DENEVE:
So as I mentioned, we are doing more work on the origination side, so continuing to develop those relationships with industrial customers. We have a bit different perspective on this than our competitor. We believe that we look at our overall portfolio and balance between contracted and merchant assets, so certainly to the extent we continue to develop the contracted side and we maintain that balance that would allow us to take more merchant exposure on building a new project in Alberta. So we don't see a need for having anywhere near that level of contracts directly with industrial customers, nor do I think it's easily done.

LINDA EZERGAILIS:
And just a follow-up question on a slightly separate note: in terms of partnering for future projects beyond Shepard, you mentioned that you're looking for an equity partner. Would that be a financial partner or an operating partner, and how do you think about the

complexity of partnering on a project level basis, versus kind of across your fleet?

BRIAN VAASJO:
So, likely the ideal partner would be certainly an industry participant that would take also part of the commodity position. But in terms of partnering, we're very comfortable with partnering. Today we have partnerships with TransAlta, we have a partnership with ATCO; we've entered into a partnership with ENMAX, so we're very, very comfortable with partnering and believe that the way that we've approached it through these partnerships, has a very good balance. Certainly the ability to dispatch our megawatts, the ability to have some significant influence both ways in respect of ongoing maintenance and expenditures around facilities to us is very important.

So again, we're very, very comfortable with partnerships, as long as those agreements are structured in a way that is consistent with the kinds of partnerships we have.

LINDA EZERGAILIS
Thank you.

ANDREW KUSKE:
Andrew Kuske, Credit Suisse. I guess this question for Brian and also for Stuart, and just relates to the finances and the balance sheet. It looks like you've got ample balance sheet capacity to take on more debt; somewhere between $500 million to almost a billion dollars of incremental debt, based on the numbers you've presented. So how do you think about the option value of that excess balance sheet capacity at this stage? Are you really running a balance sheet that's really light on debt at this point, because of the market conditions in Alberta, or are you really thinking going through with Shepard, that you want that excess capacity just on a contingency basis? Or is there something else sort of lurking in the shadows that you're preparing for?

STUART LEE:
No ghosts or dark demons in the shadows. Our expectations – and part of the reason why we're maintaining that excess capacity is a function of we've commented time and time again we're committed to maintaining that investment grade credit rating and a belief that we need to maintain that. And particularly in a high development capital spending profile, where you're not getting the FFO – you're obviously incurring the debt – it puts some additional pressure on your credit metrics and so it pushes us to probably a little less leverage than we'd ultimately like to be.

But as we see power prices improve, as we see some of the development spend come down a little bit, I think we're pretty well-positioned to add in some of that incremental debt and obviously that will drive earnings.

ANDREW KUSKE:
So is it fair to say if we saw a recovering power market at both New England and Alberta, or really one of the two, that you'd try to layer more debt if you could lock in more contracts at more robust levels?

STUART LEE:
Yeah, we'd look to take on some additional debt and again, it would be subject to trying to maintain that comfort level of being well within the expectations of maintaining investment grade and ultimately a BBB rating.

MATTHEW AKMAN:
Matthew Akman, Scotiabank. A few questions on the Shepard deal. When you talk about contracts for differences between now and 2015, normally those refer to contracts where you have some operating responsibility or risk, but there's no plant there operating until 2015, so what do you mean by contracts for differences? Is that just a straight up hedge?

BRYAN DENEVE:
Yeah, that's correct. In the case of 2013 and 2014, those are seven by sixteen hedges, so they're hedges for the peak hours in Alberta, and they're settled financially, versus the strike price and what the spot price settles at.

MATTHEW AKMAN:
Okay, thanks.

BRYAN DENEVE:
And so really what it is doing is, it's hedging the output on our existing portfolio, where we have length in those years.

MATTHEW AKMAN:
But there's no plant operating risk attached to those contracts is there?

BRYAN DENEVE:
Oh, it depends on what our overall position is at the time, so certainly if we were taking a short position, which is unlikely, but then there would be that operational risk. Otherwise, if we have a long position, we can meet that obligation, no problem.

MATTHEW AKMAN:
Okay, thanks for that. Separately, on the Shepard contract: when it starts in 2015 and goes forward from there, in your contract with ENMAX, is fuel just a pass-through then back to them?

BRYAN DENEVE:
That's correct. The tolling arrangement is structured in a manner where we will receive a fixed capacity payment on a monthly basis. They will manage the fuel supply as part of the contract, and O&M costs will be a flow-through to ENMAX as the off-taker.

MATTHEW AKMAN:
Thanks for that. And finally on the Alberta power price, I'm just wondering if you guys believe that gas prices are correlated with Alberta power price and whether gas price fluctuations would affect your view on pricing or do you think that those are independent? It looks from your charts that your spark spreads charts seem pretty highly correlated with power prices and you've got a gas price chart on there, so it seems to imply that you think gas is a major variable there, but I'd like your view on that.

BRYAN DENEVE:
Certainly when you look at forward two, three, four years out, we would see a lot higher correlation between forward gas prices and forward electricity prices. But certainly when you look in the shorter term, even when you get to month ahead or obviously during the month, that correlation is reduced in Alberta. So you certainly see events happen where the electricity price breaks apart from the gas side, and part of that's due to the fact that we've had a lot of wind come on in Alberta that's driving some of that, and also just the nature of our market structure here. Whereas in the New England market, we see a tighter correlation both in the forward market and near term – much higher correlation than Alberta.

MATTHEW AKMAN:
Thank you.

BEN PHAM:
Hi there, it's Ben Pham from BMO Capital Markets. Just a question on capital allocation and in particular your comments on dividend growth, Stuart, there; and I know that last year you've mostly indicated the potential for dividend growth in 2013, just post Quality Wind, in-service dates and now we're at that point right now, and obviously your cash flow expectations are pretty much flat heading into 2013, but you do have a more contracted position over the next few years, so more transparency on the cash flow. So can you talk about just the degree in which the door is open for dividend growth in 2013, and maybe heading into 2014 as well.

STUART LEE:
Sure; thanks Ben. So, as we look at our requirements and where our dividend is at currently, we're very comfortable that the existing dividend and stability will always come first. But in addition to that, as we look at the fact that we have some fairly significant growth projects that need to be financed, and the fact that we would like to minimize any additional equity raises associated with that. Our first priority will be maintaining the existing dividend and over time well-positioned for growth, but not likely in the very near term.

BEN PHAM:
Okay, thanks for that. And then just back to the credit rating downgrade at S&P and obviously your commitment to move towards BBB, any sense of attacking that in terms of looking at improving your business risk profile, i.e, just relooking at just your target - instead of moving 50% contract and 50% merchant, more just moving the business's profile higher on that side, just to move that credit rating up over time?

STUART LEE:
Yeah, good question. If you read through S&P's analysis, their overall view is that we have a strong business risk profile, so they continue to believe that the overall business and the way it's structured provides a very strong risk profile. Their key concern - part of the reason for their credit move – reflects the fact that they view the Alberta power price market at about 10% lower view than where the market's at and where our internal forecast might have been at. And took a fairly bright line approach to the FFO to debt metric, and that was really the impetus of the ratings action.

I don't think it really had a lot to do with the overall business risk profile and in fact, as you layer on things like Shepard – and you saw in Bryan DeNeve's analysis our contracted ratio of EBITDA is moving up meaningfully over the next three or four years, and our view would be that's very supportive of a higher rating over time.

ROBERT KWAN:
Robert Kwan, RBC. Just on the back of the decision to sell Halkirk, I wanted to explore a little bit some additional thoughts on capital efficiency or capital recycling. Do you have an interest, or see some room within the credit rating to sell further assets, maybe using some of the proceeds to buy back some of the EPCOR stake?

STUART LEE:
So again, as we look at the core assets, we're very comfortable with the portfolio we have. And looking at buying back the EPCOR stake, ultimately we would like to see that float and have the additional liquidity in the marketplace. And so I don't think on its own - if you look at the size of the stake, it's around $600 million; you'd have to do something fairly substantive on the assets side to be able to do that and you'd likely have to do it in conjunction with a public offering or a public and private offering. So no near-term expectations around doing something like that. If

there's a view that you could add value by doing it, certainly we'd look at it, but nothing that we've looked at would suggest that that math would work.

ROBERT KWAN:
Not even the thought of selling some renewables at 10 or 11 times EBITDA and buying back your stock at - you want to call it seven and [inaudible]?

STUART LEE:
Again, what you're doing is, if you look at our trading multiple it's a balance between merchant exposure and contracted, and you could sell off the entire contracted portfolio at a premium, but then what would likely happen is your stock price would start drifting towards a US IPP type of multiple, based on being fully merchant. So it's a bit of a short-term view on how to trade off asset value realization with the stock price.

ROBERT KWAN:
And I guess just on quasi-merchant assets, if you look at the New England assets, you've got a flat outlook for 2013 versus 2012 and if I look at your pricing chart, it looks like capacity price is about flat, but you expect spark spread to ease going into 2014. Is that a fair assessment as to what you're seeing at the plants. And if so, given recoveries – and it's not just you - just across North America seem to be taking a heck of a lot longer than people expected – is there any contemplation of selling those assets?

BRIAN VAASJO:
Well, as I had said earlier, when we go through and we look at our long term planning process, we do very much challenge our strategies, we do very much challenge our markets, we do continually look at different variations, should we continue to be in this market, or should we move to a different market? And when we look at the two merchant markets that we're in today, we're satisfied that they represent both diversification of merchant risk and they represent fairly reasonable markets. Certainly Alberta is very strong and the Northeast market at this point in time is reasonably stable as we talked about. Certainly some upside depending on - one of the things that we didn't comment on is that depending on some environmental regulations, you may well see a significant amount of retirements happen earlier than was being suggested. So there does remain some upside in that market.

But we don't make those decisions in a vacuum; for example, we look at ERCOT. ERCOT's a very natural alternative market for the merchant markets that we're in and as we look at ERCOT, there's certainly now starting to be a little bit of regulatory instability there. But it's a market that traditionally has done reasonably well; it's very similar to Alberta. There's no barriers to entry and essentially, it goes through very wide cycles and as everyone here knows, the last time they hit the bottom of the cycle, there was plants that were basically shuttered – a lot of plants that were basically shuttered. And that kind of volatility in the overall market, we don't believe suits us very well.

So, again, we continually look at the markets, we continually look at our investments and consider the best way in which we can utilize the capital and diversify our portfolio.

ROBERT KWAN:
Thank you.

RANDY MAH:
Any other questions?

JEREMY ROSENFIELD:
Jeremy Rosenfeld from Desjardins. Just a follow-up on that last question: if you take a longer-term perspective, is it maybe not the right time to be actually deploying capital into markets that are weaker and where you're seeing asset valuations on a lower end of a cyclical range in the anticipation that markets will strengthen over time, and that those assets will ultimately appreciate in value going forward? So in New England here, specifically.

BRIAN VAASJO:
So when we look at the asset values and if you assume reasonably efficient markets, if you have capital and capital availability, the time that you actually want to buy or invest is at the bottom of the market, so that as markets move up, you can benefit from that lift. So if you take the two activities that we're talking about today – the participation in the Shepard project and you look at the sale of the Halkirk project – certainly if we were out in 2017 when everyone's expecting significantly higher power prices, we would probably be able to sell that asset for more.

When you back up and you look at today's market and the participation in the Shepard project where the current outlook is - and as everybody knows, ENMAX has been looking for a partner for a considerable period of time associated with that project – where we are today in the market, has resulted in probably them experiencing a lot less upside than they had initially anticipated.

So for example, there's no promote associated with our costs of participation in the project. Typically you would see that, especially when you've got a project that's half-developed. So we're gaining the benefit from an economic sense in utilizing our capital today.

And when it gets to where markets are say more robust, as Stuart said, we expect to be, because of the participation in that project, much stronger at that point in time. So we'll be able to - whether you look at the ability to lever, whether you look at it - any way you look at it, our financial capacity to do more is greater in 2017 - 2018 than it is without that project.

JEREMY ROSENFIELD:
And then, tying into that, just touching on the valuation point that Stuart made, do you maybe see sort of the discount in the valuation now as a reflection of the strength that you have in the portfolio in the Alberta market, and the fact where it is relative to power prices right now, relative to where it's going to be in the future – based on your expectations.

And the real question is, going forward do you reach a limit at some point in terms of saturation within the core Alberta market? And at what point do you not get any additional value for further activities within that market, and relative to let's say, diversification in other markets?

BRIAN VAASJO:
So our investors, as we understand in speaking to the analyst community and in terms of speaking directly to investors, they generally have a broad view as to why they are investing in Capital Power and why investors would look to invest in Capital Power. One is that certainly there is some appeal to the upside and on the merchant side, and certainly the Alberta market - our perception is - investors and the financial community see that as a robust market. I would think at some point, as we continue to develop a position in the market and recognize there is a limitation - certainly with the building of Halkirk, with the building of the Capital Power Energy Centre, that pretty much exhausts most of the capacity for growth in the market from a generation standpoint.

We are increasing our position in the market and our percentage in the portfolio. Where I think it starts running into limits is to whether it continues to make sense, is where you get indifferent. And we're not indifferent yet. When you add the kind of facility that Shepard is and how it fits in our portfolio, and then you look forward and you look at the Capital Power Energy Centre, and that is going to be the most efficient natural gas plant in Alberta, and it'll have tremendous turndown capability.

I mean, it's like a massive peaker and when you can add to your portfolio assets that, as Bryan was describing and looking at the whole strategy and the whole thinking around the Clover Bar Energy Centre, those economics didn't include the portfolio impact. And as you bring top quality assets with different characteristics to that portfolio, you're continually creating tremendous value beyond what you'd normally experience in other markets.

So, eventually we'll build out in the Northeast over time over a long period of time – a portfolio that has that kind of flexibility and that kind of value add. But when you get to the point where you're just adding mass, but you're not adding those unique attributes in the market that have great portfolio benefits, then you start reaching a point where you say, it probably doesn't necessarily make a lot of sense for us to spend money in Alberta versus potentially other places.

JEREMY ROSENFIELD:
Thanks a lot.

RANDY MAH:
Question in the middle here, Jessie. I think it's her. Okay, Paul.

PAUL LECHEM:
Okay, Paul Lechem, CIBC. Just a question on the Capital Power Energy Centre and given that there's already another proposal in the markets with the same timeframe, it doesn't seem like there's the potential for both to go ahead, so how should we think about - I mean, you talked a little bit about it - what you see the advantages are, but how can we think about the steps you're going to take to actually get to a sanctioning decision, and what level of contractedness do you need for that plant to go ahead? What do we see as the next steps in terms of reaching a decision?

And then second to that, if you were to proceed with that, does it preclude you from developing your southern US projects from a capital allocation standpoint? Would you be able to take on more than one large project through that timeframe?

BRIAN VAASJO:
So maybe the answer to the last question first. In regards to our capital capability we comment that we'll be positioned to complete that project as early as 2017, but may well be out to 2020. The chart that Bryan put up more indicates that the right timeframe for completion is sort of 2018 - 2019, at least in terms of our outlook now. So you're looking at significant capital spends in 2017, 2018, 2019, that kind of timeframe.

And when you scroll forward, what would be happening in terms of the increasing power prices in Alberta, in order to see the price signals to proceed and so on you'd see that we'd have a tremendous financial capability at that point in time. So I don't see that we'd be limited to one project at that point.

Now, addressing your other question about there being a couple of projects out there, yeah, there is absolutely two, certainly. And there's other people who have other projects that are on the shelf - they had looked at before - that make some sense. The fact of the matter from our perspective is that it is largely a merchant market. Don't believe that there is that much ability to enter into long-term contracts to say have, even half of the facility fully contracted.

Now as we move forward, if those sorts of opportunities start arising in the market – and again, haven't really seen one outside of the Shepard project, haven't really seen or heard of a long-term tolling arrangement in the province in a number of years; don't really think that that capability is there. But if it is there, or there are parties out there that are contemplating long term contracts, I think that they would end up certainly speaking to us as well.

So we don't have a threshold; again, with the right signals in the market and as we've expressed a couple of times, recognizing fully that if we go forward and build that project, we'll need to be focusing on contracted assets to offset that in the portfolio. So we would be prepared to build that on a fully merchant basis, and we believe we can attract partners who would likewise be willing to build it on a fully merchant basis.

PAUL LECHEM:
So you say that you're looking for pricing signals in the market before you would make a sanctioning decision? Because it doesn't seem like the pricing in Alberta would be moving up until 2016 and beyond.

BRIAN VAASJO:
Well, that's why we say 2017 - 2018, would be more the timeframe we'd see. On the other hand though, there certainly can be retirements of coal assets that take place before that. What Bryan was describing and showed on the charts was the retirement of coal plants according to the capital stock turnover regulations; not based on Alberta regulatory or environmental restrictions and what may be economic decisions made by power producers in the province and shutting down coal plants. So that's what would really move it forward.

PAUL LECHEM:
Thank you.

RANDY MAH:
Go ahead, Linda.

LINDA EZERGAILIS:
You mentioned that you're looking at two sites for your CPEC and I'm wondering if you can comment on what the different attributes are; is it because one is closer to load, maybe already somewhat of a brownfield site? And how might the line losses come into the equation in terms of the relative attractiveness of the two sites, or other third party alternative options that are floating out there?

BRYAN DENEVE:
So it's a very interesting question on location of new gas-fired generation in Alberta and of course, on the business development side we work closely with the construction engineering team in terms of looking at technical configurations and the implications of locating them in different spots in the province.

So the sites we're looking at are both brownfield sites. They basically would have very limited costs when it comes to interconnection to the grid. Readily available gas supply gas connection and in terms of cooling water, very accessible also. So from a permitting perspective, they're very easy to move forward and there's a lot of cost savings, because they are brownfield sites.

I think one of the sites goes further; it has that, but also goes further in terms of, there are some things that we can do strategically with the facilities that are already located on that site, to create additional synergies. So we're very excited about continuing to explore that and bringing it to bear.

So when you look at central Alberta versus southern Alberta where Shepard is, you have a number of trade-offs. Elevation's a factor, so certainly locating at a lower elevation will improve performance versus a higher elevation. You have the line loss factors, as you mentioned. Certainly southern Alberta has an advantage over central Alberta in that regard.

But as I mentioned earlier, with the addition of Shepard, we start to hedge ourselves on the line loss equation, so regardless of how that plays out as we move forward where load growth occurs, or what regulatory decisions are in regard to line losses, it generally will hurt us on one end, but help on another, so we're almost hedged in that regard. So that is a consideration.

But I think fundamentally at the end of the day, new supply can be built at a brownfield site; it's sort of table stakes to have that infrastructure there. And then it's looking to get the edge over and above that in terms of the best configuration that can perform in our market structure – the island market – the flexibility, but then seeing if there's some additional advantages that can be brought to bear with a participant or a partner that goes outside the power industry, and whether there are synergies that can be found.

JUAN PLESSIS:
Juan Plessis, Canaccord Genuity. Stuart, does your EPS guidance for 2013 include any reduction in depreciation expense due to the extended coal plant lives from the greenhouse gas legislation that was implemented earlier this year?

STUART LEE:
So, a good question, Juan. Our expectation is it will move from a 45 year life on our assets, and what's implicit in that is moving to a 50 year life expectancy for our coal assets.

JUAN PLESSIS:
Can you share with us the magnitude of that?

STUART LEE:
So I'm going a little bit off the top of my head; it's around $7 million per annum, so maybe it's obviously in that kind of $0.04 to $0.05 range. But that's off the top of my head and I'll double-check my figures later.

JUAN PLESSIS:
Okay, thanks for that. And you have a large growth capital spend in 2013 and 2014. At what rate are you capitalizing your interest at?

STUART LEE:
So under IFRS you capitalize based on your expected overall corporate borrowing costs, so we'd expect to capitalize in the kind of the 5% to 5 1/2 % range; likely in about the 5% range. Obviously if you're using short-term financing, which we would normally use associated with a project like that, your actual borrowing costs might in fact be lower and so there may be a positive impact on an IDC basis associated with that delta.

JUAN PLESSIS:
Great, thank you.

RANDY MAH:
Go ahead, Matthew.

MATTHEW AKMAN:
Thank you very much. I just wanted to check the efficiencies of the plants – the gas plants - that you guys are building. On Shepard: the equipment on Shepard was rated in kind of the low 6,000s heat rate; is that kind of what you guys are expecting out of the project?

BRYAN DENEVE:
Yeah, as I was mentioning to someone earlier, with heat rate it's always tricky, because it can be calculated five different ways. But on an apples to apples basis, if you were to look at Shepard, it would probably be in the 6½ to 7 range, and you would see for example, our Tiverton and Rumford facilities in New England, which are about ten years old, they would be sort of the 7.2 to 7.5 on an apples-to-apples basis.

So you basically have a half point drop an increase in efficiency on a heat rate basis with Shepard versus those facilities. And then we would see an additional uptick with the new Capital Power Energy facility in central Alberta.

MATTHEW AKMAN:
So where would that one land?

BRYAN DENEVE:
I would say it would probably drop another 0.2, so if Shepard was 6.8, it would be about 6.6.

MATTHEW AKMAN:
And I guess just on slide 39 of the merchant power section, there's longer-term projections for spark spreads. I'm just wanting to confirm that those would assume that there's no new plants built, right? I mean, once you guys start building these plants, spark spreads aren't going to go to $75 or $50, or whatever you've got there: they'll be more contained than that, I presume, because those are following reserve margins absent new build, right?

BRYAN DENEVE:
Those spark spreads would reflect addition of new plants in response to the pricing signals, so certainly we would see the reserve margin of course continue to settle in that 15% to 20% range, and the graph showed it going below, but that's without any new additions.

But the graph to the left, which shows the spark spread, that's after the addition of new supply.

MATTHEW AKMAN:
So you think even when you add all these gas plants - all this capacity - the spark spreads are going to go to $50, $75?

BRYAN DENEVE:
Right. They'll be consistent with what we've seen over the last several years, which has been sort of the $40 - $50 a megawatt hour, and of course, that'll increase as the cost of building new supply increases in the province.

MATTHEW AKMAN:
Thank you.

DOMINIQUE BARKER (CIBC Global Asset Management):
Could you just discuss what happens on Shepard in the event that one of the parties wants to sell?

BRYAN DENEVE:
So in terms of the structure of that agreement, it's very similar to the agreements we have in place around Keephills and Genesee, so there are provisions in there for if one of the parties does want to sell and exit the partnership. And there's similar provisions; I can't really say too much more than that at this point.

RANDY MAH:
Okay, looks like there are no more further questions. Brian, any closing comments?

BRIAN VAASJO:
Thank you, Randy. And again, we'd like to thank you very much for your interest this morning in Capital Power. As I said earlier, we're pretty excited about the news that we announced this morning and some of the developments we see happening, in particular around the Alberta market, and continue on our track towards building a very reliable, stable and competitive power generation fleet, both inside Alberta and across our other target markets in North America.

And, do see some of the challenges in front of us; certainly looking at softer power prices over the next couple of years, and think that we have certainly responded and will continue to respond in terms of thoughtful, measured ways in which we can move our costs and our revenues to maximize the value of our existing assets.

So again, thank you very much for your interest this morning and we will be around through the lunch hour, if you have any further questions for us. Thank you.

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