Capital Power Corporation Conference Call
Fourth Quarter and Year-End 2012 Results – March 1, 2013

CORPORATE PARTICIPANTS
Randy Mah
Senior Manager, Investor Relations

Brian Vaasjo
President and Chief Executive Officer

Stuart Lee
Senior Vice President Finance and Chief Financial Officer

CONFERENCE CALL PARTICIPANTS
Juan Plessis
Canaccord Genuity

Ben Pham
BMO Capital Markets

Linda Ezergailis
TD Newcrest

Robert Kwan
RBC Capital Markets

Matthew Akman
Scotiabank

Osvaldo Matias
CIBC World Markets

Andrew Kuske
Credit Suisse

Jeremy Rosenfield
Desjardins Capital Markets

PRESENTATION
OPERATOR:
Welcome to the Capital Power Corporation's conference call to discuss the fourth quarter and year-end 2012 results. At this time all participants are in listen-only mode. Following the presentation we will conduct a question and answer session. Instructions will be provided at that time for you to queue up for questions. I would like to remind everyone that this call is being recorded on Monday, March 4th, 2013 at 9:00 AM Mountain Standard Time. I will now turn the call over to Randy Mah, Senior Manager Investor Relations. Please go ahead.

RANDY MAH:
Good morning and thank you for joining us today to review Capital Power's fourth quarter 2012 results, which were released on Friday, March 1st. The financial results and the presentation slides for this conference call are posted on our website at www.capitalpower.com.

Joining me on the call are Brian Vaasjo, President and CEO, and Stuart Lee, Senior Vice-President and CFO. After our opening remarks we will open up the lines to take your questions.

Before we start, I would like to remind listeners that certain statements about future events made on this conference call are forward-looking in nature, and are based on certain assumptions and analysis made by the company. Actual results may differ materially from the company's expectations due to various material risks and uncertainties associated with our business. Please refer to the cautionary statement on forward-looking information on Slide 2.

In today's presentation, we will be referring to various non-GAAP financial measures as noted on Slide 3. These measures are not defined financial measures, according to GAAP, and do not have standardized meanings described by GAAP and, therefore, may not be comparable to similar measures used by other enterprises. Reconciliations of these non-GAAP financial measures can be found in the Management Discussions and Analysis for the fourth quarter of 2012. I will now turn the call over to Brian for his remarks, starting on Slide 4.

BRIAN VAASJO:
Thanks Randy, and good morning. I'll start off with an update of significant items in the fourth quarter.

At the end of 2012 we added nearly 200 Megawatt (MW) [300 MW] of wind production to our fleet with the successful completion of two projects located in BC and Alberta. On November 6th, Quality Wind began commercial operations on schedule and approximately 10% below its $455 million dollar budget. Halkirk began commercial operations on December 1st, which was slightly ahead of schedule and at a cost that is approximately 8% below its $357 million dollar budget.

In December we announced major long-term expansion plans in Alberta. First, we signed an agreement with Enmax to acquire a 50% interest in the Shepard Energy Centre. The 800 MW Shepard facility is located in east Calgary and is on schedule for COD in the first quarter of 2015. The agreement with Enmax includes a 20-year tolling agreement with a fixed capacity charge and cost flow-through.

We also announced plans to develop a new project called the Capital Power Energy Centre; it will be a natural gas combined cycle facility with up to 900 MW of capacity. Start-up of commercial operations for the Capital Power Energy Centre is targeted for the 2017 to 2020 timeframe, when additional generation will be required to meet growing demand and to replace generation from the retirement of coal units.

With the addition of these two large facilities Capital Power will continue to own the best fleet of power generation assets in Alberta with approximately 3,100 MW of owned capacity in the fastest growing power market in North America.

Turning to Slide 5. Q4 2012 results were generally in line with expectations before two events. However, as a result of the impact of these events, normalized earnings per share of $0.23 in the quarter were down 36% from Q4 2011 while funds from operations of $83 million were down 5.7% year over year.

The first event impacting Q4 2012 results was related to a heat rate option on the Bridgeport facility. The Northeast US plants incurred a net loss of $10 million dollars relating to this option and actions taken to mitigate the natural gas exposure associated with the option.

The second item impacting Q4 2012 results was significantly lower than normal wind for the first two months at the Quality Wind facility, which began commercial operations in early November. Historically the three-month period from November to January has featured the strongest wind regime during the year, which led to a forecast capacity factor of 47%. However, in November and December of 2012, the capacity factor was well below that level--at 27%--which resulted in lower than expected operating margin of approximately $6 million dollars. The capacity factor has improved in January and February of this year, and is now performing in line with our expectations.

Although these two events negatively impacted our financial performance in the fourth quarter of 2012, they are not expected to impact our 2013 expectations. Stuart will elaborate further on these two events in his remarks.

Slide 6 shows the operating performance of our fleet with respect to plant availability for the fourth quarter of 2012 compared to 2011. Average plant availability of 89% in Q4 2012 met our expectations and was slightly higher than the 87% recorded in the fourth quarter 2011.

A Genesee 3, 9-day extension to a plant outage reduced its availability to 56% in the fourth quarter. The additional days required for the planned outage was related to normal course maintenance activities, which required additional time to inspect and repair certain piping. Plant availability at the five contracted facilities in Alberta, BC, and Ontario was strong and averaged 98%.

For our three Northeast US commercial plants, the 86% plant availability was lower than expected due to pre-emptive outages related to Hurricane Sandy. I'll now turn the call over to Stuart.

STUART LEE:
Thanks, Brian. Starting on Slide 7, I'll start off by providing more details on the Bridgeport heat rate option that negatively impacted Q4. The Bridgeport hedge is a heat rate option product that was structured to closely resemble the plant's operating characteristics, and it was in place when we acquired the Bridgeport facility in 2011. The basis risk on the hedge existed because there's a mis-match between the exposure being hedged, i.e. the power plant, and the hedge, i.e. the heat rate option.

The Bridgeport facility is long power at Bridgeport power out and short natural gas at Bridgeport's gas point, which is at the Iroquois Zone 2. The Bridgeport hedge was set up to offset our long power at a different power natural gas point, which were the Connecticut Zone and the Transco New York Zone 6, respectively.

Turning to Slide 8, you can see the pricing correlation between the two locations has historically been very high for both power and natural gas, as illustrated in the chart. Over nearly a three-year period, from February 2010 to October 2012, this high correlation has been very consistent except for the period in December 2010, when there was a more volatility due to extreme cold temperatures in the New England region relative to contiguous markets.

As indicated by the circle on the chart, unprecedented natural gas demand levels combined with supply constraints resulted in significantly and highly unusual widening of the Zone 2 to Zone 6 gas price spreads in November and December of 2012.

Moving to Slide 9. Actions were taken to limit the exposure and, in January 2012, the natural gas basis risk for the April to October period was hedged; but, throughout 2012, we were unable to hedge the last two months of the year due to liquidity constraints and the limited number of counterparties. Trades were executed at a reasonable cost to limit the remaining exposure to the natural gas basis risk associated with the option for the November and December months. December physical natural gas consumption for Bridgeport was locked in at prices higher than actual prices resulting in an additional loss. However, this was partly offset from gains realized off natural hedge executed to reduce the locational basis risk. Going forward, what's important is that the Bridgeport option expires at the end of 2013 and this gas price differential risk has been fully mitigated for 2013.

Turning to Slide 10, I'll review the early performance of our two new wind facilities. As Brian referenced, Quality Wind, which began commercial operations in early November last year, experienced lower than normal wind conditions in the first few months of operations with a capacity factor of 27%. Since then, we've seen a return to more normal wind patterns. The average capacity factor is 35% in the four months since COD, which is in line with our long-term expectations.

At Halkirk, which began commercial operations in December, performance has been in line with our expectations of a 38% capacity factor. What is unique about Halkirk is it's located in central Alberta and away from the majority of the province's wind capacity that is located in the southwest region of the province. Due to this location, its captured power price is at a different discount to the average power price relative to the wind facilities located in southern Alberta, enhancing profitability to the facility.

Turning to Slide 11, I'll quickly cover the financial performance for the fourth quarter. Revenues and other income on a comparable basis to last year were $330 million dollars, down 4.9% from Q4 2011. Comparable EBITDA was $100 million dollars in Q4 2012, down 17% on a year-over-year basis due to two events referenced earlier: the Bridgeport heat rate option and the lower wind at Quality Wind. Together, these events reduced 2012 EBITDA by $16 million dollars after tax, or approximately $0.13—or, $0.12 per share. I would highlight the fact that none of these events will spill into 2013.

Normalized earnings per share was $0.23 in the fourth quarter, compared to $0.36 last year. And funds from operations, excluding non-controlling interest in CPILP, were $83 million dollars in the fourth quarter compared to $88 million dollars in Q4 2011.

Slide 12 shows our financial performance for the full year 2012. Revenues and other income on a comparable basis to 2011 were approximately $1.3 billion dollars, down 3.7% from 2011. Comparable 2012 EBITDA was up 18%, at $456 million dollars, primarily reflecting the full year contribution of Keephills 3 in 2012, compared to four months in 2011. Normalized earnings per share was $1.29 in 2012, compared to $1.24 in 2011. Funds from operations was $381 million dollars in 2012, up 8.2% compared to 2011. Finally, cash flow per share was $3.89 in 2012, which was unchanged compared to 2011.

Turning to Slide 13. This slide shows our Alberta commercial portfolio hedge positions at the end of 2012. Entering into 2013, we're at 49% hedged, at an average hedge price in the mid-$60/MWh range. For 2014, we're at 37% hedged at an average hedge price in the mid-$50/MWh range. And for 2015, we're at 31% hedged, also in the mid-$50/MWh range.

For every $1/MWh change in Alberta power prices, sensitivity is a $4 million dollar impact in EBITDA in both 2013 and '14 and a $6 million dollar impact in EBITDA in 2015.

I'll conclude my comments by providing our financial outlook for 2013 as compared to 2012 on Slide 14. Overall, normalized EPS and FFO for 2013 are expected to be in line with 2012. Brian will comment on the specific financial target shortly.

The 2013 financial targets are based on an average power price in Alberta at $58/MWh, compared with the $64/MWh average price in 2012. On a year-over-year basis, we expect lower realized prices on our unhedged position, profitability from the Clover Bar peaking facility, and incentive revenues from Genesee 1 and 2. This is expected to be offset by the full year contribution of Halkirk and Quality Wind and stronger plant availability of 93%, compared to 91% in 2012. The 93% plant availability target reflects two major outages at the Genesee 1 and Keephills 3 facilities. I'll now turn the call back to Brian.

BRIAN VAASJO:
Thank you, Stuart. Starting on Slide 15, I'll review our 2012 performance against our targets, and outline our 2013 targets that were announced at our Investor Day last December. We were successful in meeting our operational targets for 2012, by achieving an average plant availability of 91%, sustaining CAPEX of $102 million, and $208 million in maintenance and operating expenses. For 2013, we are targeting 93% plant availability, sustaining CAPEX of $105 million and maintenance and operating expense between $225 to $245 million.

Slide 16 outlines our development and construction targets. As highlighted earlier, we were successful in completing the two wind facilities, Quality Wind and Halkirk, on time and under budget. We made progress on the Port Dover & Nanticoke Wind projects in southern

Ontario last year and have begun construction. We are targeting commercial operations in the fourth quarter of this year with a $340 million dollar budget.

Our K2 Wind project in southwestern Ontario, we revised our expectation to receive full notice to proceed to late 2013 or early 2014. Also, the previous expected commercial operation date of 2014 has been moved to early 2015 due to delays in the anticipated timing of the delivery of the turbines. There was no impact on the total project costs for K2 from these delays.

Finally, our target for the Shepard Energy Centre is to continue tracking our $860 million dollar budget for the project.

Slide 17 shows our 2012 financial results compared to targets. The most significant cause of the variance from the targets was the lower-than-expected Alberta average power price at $64/MWh, which was $10 lower than our $74/MWh assumption used to establish our annual financial targets. The other main factors were the losses on the settlement on the Bridgeport heat rate option contracts, lower wind volumes at Quality Wind, and lower EBITDA for the Northeast US plants, primarily due to the second quarter unplanned outage at Bridgeport.

Our 2013 financial targets are based on forecasted Alberta power prices of $58/MWh, and include normalized earnings per share of $1.20 to $1.40, funds from operations of $385 to $415 million dollars, and cash flow per share between $3.80 to $4.20 per share. I'll now turn the call back over to Randy.

RANDY MAH:
Thanks, Brian. Operator, we're ready to start the Question and Answer session.

QUESTION AND ANSWER SESSION
OPERATOR:
Thank you. Ladies and gentlemen, if you'd like to ask a question please press '01' on your keypad. We do have our first question and it's from Juan Plessis from Canaccord Genuity. Please go ahead.

JUAN PLESSIS:
Ok, thanks very much. Brian there was no mention of the Halkirk sales process in the fourth quarter MD&A or in your comments. Can you provide us with an update on that sales process?

BRIAN VAASJO:
Good morning, Juan. Actually, as you may recall in the Investor Day and our discussions around that announcement that was—I'll call it— the base case for the sale of assets that we would conduct through this year to come up with proceeds for early next year. As we also indicated, we'll be looking at and considering other alternatives that may be more optimal for Capital Power in terms of asset sales. So we're continuing to look at various alternatives. We haven't actually started a specific sales process yet; but for example, one of the alternatives that is coming up is potentially there may be some advantages to bundle a couple of wind farms together and sell an interest in the bundle, as opposed to selling Halkirk. So those are the kinds of things that we are continuing to look at to find the optimal combination of appropriate risk levels, the proceeds, and the degree to which we think we are realizing value on the sale of assets. Certainly, the sale of Halkirk continues to be high on the probability list but we are looking at other alternatives.

JUAN PLESSIS:
Ok, and when would you expect to have a decision on that?

BRIAN VAASJO:
We'd expect that to happen sometime over the next couple of months. Generally thinking the last part of this year as the time to execute.

JUAN PLESSIS:
Ok, thanks for that. And staying with Halkirk, what happened to get the capital costs 8% below budget versus about 3% that you were indicating at your Investor Day in December?

STUART LEE:
So primarily Juan, it's just the completion of negotiations with some of the contractors associated with that and removing the remaining contingency based on, it's almost final now, negotiations with the contractors.

JUAN PLESSIS:
Ok, thanks for that. And just finally with respect to the heat rate option at Bridgeport. You've mitigated the exposure for 2013, but going forward beyond 2013, would you be inclined to enter into a similar heat rate options for this facility?

STUART LEE:
So Juan, we continue to look at potential heat rate options, but again not looking to take the type of basis risk that was embedded in that contract when we bought the facility, where you've got different gas delivery points and points where the option is being executed. So, that's the one type of risk that we wouldn't look to put into those types of arrangements.

JUAN PLESSIS:
Ok, thanks very much.

OPERATOR:
Our next question is from Ben Pham from BMO. Please go ahead.

BEN PHAM:
Ok, thanks. Good morning everybody. So my first question is on New England and I know there's been a couple of things that just — the heat rate option and some of the taxes there — just something that you didn't anticipate when you first acquired these assets. But just curious going forward, is there any other critical headlines that we should be looking for in terms of potential friction points in your New England business? Just something that sticks out that we should potentially be watching for going forward? I mean, $25 million of EBITDA, have we really hit trough levels here?

BRIAN VAASJO:
Well certainly as you look forward, the greatest disappointment in that market for us has been the lack of increasing demand that was expected to come with the US economy, and reflected in the forward curves at the time. And we've seen that drop fairly significantly over the last couple of years, as it relates to the lack of demand or growth in demand in that marketplace.

Looking forward, and continuing to be part of the investment thesis, is the fact that there should be power plants that retire due to age, cost of operation, and certainly with an expectation that there will be more stringent environmental regulations. So we do expect that particularly with the increasing comments out of Washington around the environmental agenda, we do expect that there will be different environmental regulations coming into play that will positively impact our position by reducing some of the supply. So that would be our expectations over the near to medium term, but in the direct short term really don't see anything significantly happening.

BEN PHAM:
And, just a follow up on that, and just your experience with New England and then just focusing on your growth outlook, when you look at your risk adjusted return opportunities, I mean, are you seeing better opportunities on the merchant-side still or how does that look compared to greenfield?

BRIAN VAASJO:
Well certainly if you look at the New England assets you can buy assets that are well under replacement costs. So again there aren't a lot of assets for sale in that market today. But they certainly are under and continue to be under replacement costs. So that versus a new build, from merchant general market standpoint, continues to be more the attractive side.

Having said that, and just to reiterate, we are not looking in the northeast market for merchant assets to acquire. We're actually not looking in any market for merchant assets to acquire. With our balance of merchant and contracted we continue to be focused on, predominantly, the build of contracted facilities.

BEN PHAM:
Great, thanks very much. Thanks everybody.

OPERATOR:
Our next question is from Linda Ezergailis from TD Securities. Please go ahead.

LINDA EZERGAILIS:
Thank you. I have a question with respect to the change in coal inventory fuel costs in the fourth quarter. Can you just describe what was that? Was that, kind of, a true up in terms of trend for previous quarters in the year or something else going on? And how might we think of your coal costs going forward; if there's any systemic change?

STUART LEE:
So Linda, it was effectively a true up in looking at our standard costing for coal and adjusting it in the quarter and the impact actually goes back probably a couple of years. It wouldn't just be for 2012 and if you actually back out that adjustment the 2012 costs are relatively in line with what we'd expect to see going forward. And it's really, for the most part, a true up for the last couple of years and adjusting our standard costs on coal based on current costs to extract it.

LINDA EZERGAILIS:
Thank you. And with respect to your outages for 2013, I appreciate the disclosure and I'm just wondering if you can give us a sense of when G1 and K3 will be down?

STUART LEE:
So, I think both are scheduled for Q2.

LINDA EZERGAILIS:
Both for Q2. That's great. Thank you very much.

OPERATOR:
Our next question is from Robert Kwan from RBC Capital Markets. Please go ahead.

ROBERT KWAN:
Good morning. Just looking at Keephills 3's production in the quarter and just wondering why it came in so low despite 100% availability?

BRIAN VAASJO:
So there were a couple of things there Robert. One is there was some de-rates on the transmission system that impacted its ability to actually generate. And then there was also some strategic dispatch by the owners.

ROBERT KWAN:
Ok just in terms of strategic dispatch, how do you think about that given such the low variable cost coming out of the plant? Like, was that over a 24-hour multiple periods or was that kind of trying to cycle it throughout the day?

BRIAN VAASJO:
So generally because we have a partner involved in this we're not really at liberty to get into details around why and how it was dispatched.

ROBERT KWAN:
Ok. Just, I know you have your guidance around that $58 number; just wondering if there's any refinement though? If you were cheating to either side, just particularly given the low prices we've seen to date, at least throughout the quarter for 2013?

STUART LEE:
If you look at forwards Robert for the balance of the year they continue to be in that $58 range, so I don't think we're cheating one way or the other at this point in time. We continue to believe that the forwards are a good indicator of what we expect to see the spot market deliver.

ROBERT KWAN:
And I guess with that in mind then are you looking to really try to take advantage of as much liquidity as you can get then, just to hedge up given it's pretty much where you think? Or is your thought process— it's going to be pretty close you may as well leave it open.

STUART LEE:
It's quarter by quarter. Obviously the desk takes a view depending on the expectations for a given month or period, both on peak and off peak. So I don't know that I'd be any more specific than that.

ROBERT KWAN:
Ok. And just a last question on the Capital Power Energy Centre. You talked about trying to take a partner in. At what point are you starting those discussions in earnest and how might we think about that timing?

BRIAN VAASJO:
So in respect to the Capital Power Energy Centre, one of the main elements to arrive at is what the location is. As we said, there's a choice right now. We expect to come to closure on that element of that soon, and then would start talking to prospective partners.

We have had extremely—I'll call it— preliminary discussions with a couple of parties; so certainly there's the interest there. It'll be a case of working out which partner in combination with ourselves makes for a stronger and lower-risk project. I would suggest that we probably would have an announcement by the end of the year.

ROBERT KWAN:
Ok, that's perfect, thanks very much.

OPERATOR:
Our next question is from Matthew Akman from Scotia Bank. Please go ahead.

MATTHEW AKMAN:
Good morning. Thank you. Your sensitivity analysis on page 13 indicates that there is the same EBITDA swing per dollar change for Alberta power in 2013 and 2014 even though the hedge numbers actually go down. So, doesn't stand out as totally logical, I guess, unless you're predicting significant outages in 2014? Or maybe your 2014 sensitivity does assume that the wind assets are sold? If you can just explain, Stuart.

STUART LEE:
So, there's a little bit associated with the wind asset and Halkirk and that particular item coming out in our forecasts.

MATTHEW AKMAN:
Are there also some outages you're expecting in 2014 so that you're not as sensitive to changes in prices?

STUART LEE:
Outage-wise would be pretty consistent so, as you are aware the expectations generally are a flip between every year between K3 and G1 and then G2 and G3 the next year so I don't think there's much of a difference in overall availability of our merchant assets due to outages.

MATTHEW AKMAN:
Ok, but I guess if, as per Brian's comments, Halkirk is maybe going to be sold or maybe it's not I guess, so the sensitivity could be a bit higher than that in '14 than the $4 million if it's not sold, is that right?

STUART LEE:
That is correct.

MATTHEW AKMAN:

Ok, thanks for that. Separately, G2 availability in the quarter was 94%. I don't know if there was any commentary around that or if you guys talked about having a planned outage or that there was an unplanned outage at G2?

STUART LEE:
There was no planned outages at G2. We did have some tube leaks, particularly in December, at the facility that have been repaired.

MATTHEW AKMAN:
I guess my follow-up on that, and the reason I ask is the Genesee plants have had outstanding availability, which really goes to their cash flow, yet as they age—I mean, we've seen other coal plants in Alberta with significantly lower availability over time due to tube leaks. So I'm just wondering if you guys still think, over the next five years, you can hit these, sort of, high 90's availability targets for the Genesee 1 and 2.

STUART LEE:
Yeah, our expectations continue to be that we'll be in that 95-96% type of availability numbers for those facilities. We continue to have excellent maintenance practices. Those have not changed. And therefore, we wouldn't expect any significant degradation in availability on those assets. If you're comparing it back to Q4 of last year at 100%, I don't think that would be our expectation over the long run, obviously. That's not realistic, but I do think we can maintain kind of in that 95-96%.

MATTHEW AKMAN:
No, I mean, you guys have always done a great job with plant operations. It's just more as they age; it's either lower availability or more maintenance capex usually. Sounds like you're saying a bit more maintenance.

STUART LEE:
I think we've maintained a high level of maintenance on those facilities and they're in very good shape so I wouldn't suggest that there's a significant higher degree of CAPEX that has to go into those facilities to maintain them at that level; but there is modest degradation, as you would expect on any facility over time.

MATTHEW AKMAN:
Ok. Thank you very much. Those were my questions.

OPERATOR:
Our last question is from Osvaldo Matias from CIBC. Please go ahead.

OSVALDO MATIAS:
Good morning. Just a question on New England power prices that remain strong; regional gas prices, I guess, have been also quite strong. Still reflecting some supply constraints; just wondering if you can give, sort of, your outlook for the New England facilities for 2013. I know you guys said you mitigated the hedge or the heat rate option risk but maybe talk about perhaps spark spreads and what you guys see that doing to your New England results for 2013?

STUART LEE:
So spark spreads, expect them to be kind of in the low double digits for 2013. We have seen a little bit widening, particularly in the Connecticut zone, which is positive. But overall consistent with the guidance we gave on Investor Day that we expect total EBITDA to be kind of in the mid-$39 range.

OSVALDO MATIAS:
Great, thanks.

OPERATOR:
We have one more question and it's from Andrew Kuske from Credit Suisse. Please go ahead.

ANDREW KUSKE:
Thank you. Good morning. Just would like to get a bit of perspective on how you think about the Alberta power market? I know we've talked about this before, and you can paint a very rosy picture on just demand trends. And the demand trends have been very positive over the last few years, but from a pricing standpoint could you just give some kind of description on how you really think about the pricing mechanisms within the market; and in particular in this year, Sun 1 and Sun 2 will return later in the year. There's a growing amount of wind capacity that's being somewhat constrained and then there's this transition into gas, which obviously the prices to build generation in Alberta are more expensive than elsewhere, but gas prices are lower than elsewhere in North America. So, how do you rationalize all that, and where do you think prices are going to be in the longer term?

BRIAN VAASJO:
Certainly the market is in a softening mode. You add Sun 1 and 2; it certainly is going to have a negative impact on power prices through increasing supply. Our view of the Alberta market is it's a very—I'll call it simple market—given that it is energy only, given that there are not a lot of constraints around the market. What you see are prices reacting very much to changes in supply and demand. So as we look forward we see certainly the Sun 1 and Sun 2 coming on and having a negative impact on pricing on the market. On the other hand, we continue to see pretty strong growth in demand in the province, which mitigates--certainly mitigates that over time.

We see the Shepard Energy Centre coming on, and that again, obviously will have negative implications around pricing. Again, demand over time will certainly mitigate that through to the latter part of the decade, when we see that the supply/demand balance and therefore pricing signals will be sufficient for there to be another natural gas facility coming on-stream. And that whole scenario is back-stopped by the fact that there will be significant coal retirements at the end of the decade.

So we see it as a very positive longer-term outlook, based on very simple and clear basics of supply and demand; and a high degree of predictability, at least on a forecast basis. Based, again, on the balancing of supply and demand. Of course the one real wild card, and what we see as an upside, is that the fleet in Alberta is getting older and older. And there may well be, either because of environmental regulations or because of just units breaking, potentially a significant upside in this market. So that is the way we view it.

ANDREW KUSKE:
Ok. No, that's very helpful. And then as a follow-up, do you see less volatility in pricing in particular as we move ahead and some of the larger individual coal units come offline and are retired; and they are really back-filled by smaller individual natural gas-fired units?

BRIAN VAASJO:
So certainly the market has been becoming more and more volatile over the last number of quarters, and we expect that trend to continue. Certainly as you bring on new supply, that has the impact of dampening a bit of volatility and then the volatility returns. Natural gas facilities have the characteristics of having higher availability. But certainly higher variable costs has more of an impact than coal facilities when you turn them on and off. So no, I'm not sure that we would expect volatility to necessarily, in general, go down in the future.

ANDREW KUSKE:
Ok, that's helpful. And, if I may, just one final question? In the last—not even a week—there's been a very dramatic re-pricing of the shares of Atlantic Power Corp. Obviously there's a lot of assets in there that you know all too well. Is that the kind of thing that strikes your interest from a broader perspective at this stage in time?

BRIAN VAASJO:
So from a broad perspective our strategy and the main reason for divesting Capital Power Income LP was that you had a number of assets over a broad geography and investment per asset was relatively small. So, that would certainly continue to be the same case if we looked at Atlantic Power say from an acquisition standpoint. That would be very much a reversal of what has been a very significant part of our strategy over the last couple of years of simplifying our geography, simplifying our fuel types and certainly increasing the average dollar investment per facility. So it would be pretty much an about face for us.

ANDREW KUSKE:
Ok, that's very helpful. Thank you.

OPERATOR:
We do have one last question. It's from Jeremy Rosenfield from Desjardins Capital. Please go ahead.

JEREMY ROSENFIELD:
Yeah great, thanks. Good morning, everybody. I just have one question on the heat rate option to close the loop. I'm curious as to how come you're not including this in the normalized calculations that you're doing? When you think of the use of the option does that sort of imply that it's, kind of, normal course of business and this kind of thing could happen again in the future if you don't have perfect hedging?

STUART LEE:
So Jeremy the decision around whether or not to include in normalized or not normalized is — I think you're probably right in the fact that we wouldn't expect to lock into an arrangement like that with gas price differential and so we wouldn't expect to see that type of difference going forward on the gas side. But, it's very difficult when you're hedging in New England, for instance on the electricity side, when you're looking at a nodal level, you're likely to hedge more likely at the zone level and so there is some introduction of basis differences even on the electricity side.

And while we wouldn't expect that those would have a material difference. You can't say for 100% that there couldn't be some level of dislocation between those different areas. So, that's why the decision part of our business and why we included it in normalized, but having said that we wouldn't expect that level of price differential going forward in the type of products we use.

JEREMY ROSENFIELD:
Ok, great. Then just on the K2 project, the reasons for the turbine delay. I'm wondering how come, sort of, you have that level of visibility at this stage that you can see that the turbines are not going to be on time and if you can remind us who the supplier is?

BRIAN VAASJO:
So, the supplier of those are Siemens and you may recall that is a joint venture between ourselves, Samsung, and Pattern as the three partners.

And generally speaking what's happening in Ontario is there's a significant local requirement for content and, although Siemens I'm sure could deliver turbines to us on an international basis much quicker than that. What's happened in Ontario it's because of the environmental filings to get permits and the appeals and so on. It's played a bit of havoc in terms of their schedule of providing turbines. So the whole process has essentially pushed out a number of projects—with limited capacity to produce turbines—has pushed out a number of projects, which you normally wouldn't expect given the scope and base of Siemens operations but it is basically driven by the constraints of having local content requirements.

JEREMY ROSENFIELD:
Ok. The only final question that I have is that it relates to the proceeds that you are expecting to receive from the sale of the hydro assets in BC to Innergex. Some of that money seems to have been tied up. Can you just give me a little more detail as to what has to be done here or what's the hold up?

STUART LEE:
The detail around that Jeremy is the fact that when the lease was renewed for the land, associated with Miller Creek, the lease term was shortened by BC Hydro to the term of the PPA, relative to what was previously when we went out to at least 2038 so Innergex is claiming that because of the shortened lease term they are looking for a reduced price. Our view is that BC Hydro's policy, at this point, is on any of the lease renewals that they only go as far as the PPA term but there's 100% expectation that they will extend the lease term when the PPA is extended and so no change in the overall value. And that's the primary difference in view between ourselves and Innergex and we're very comfortable that we have a strong position on that claim.

JEREMY ROSENFIELD:
Ok, perfect. I understand now. Those are my questions, thanks.

OPERATOR:
We have no more questions at this time.

RANDY MAH:
Ok, if there are no further questions we will conclude our conference call. Thanks again for joining us today and for your interest in Capital Power. Have a good day, everyone.

OPERATOR:
Ladies and gentlemen, this concludes the Capital Power Corporation's conference call to discuss the fourth quarter and year-end 2012 results. Thank you for your participation and have a nice day.

[TRANSMISSION CONCLUDED]