Capital Power
Q4 2021 Results Conference Call
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Operator
Welcome to Capital Power's Fourth Quarter 2021 Results Conference Call. As a reminder, all participants are in a listen only mode and the conference call is being recorded today, February 24, 2022. I will now turn the call over to Mr. Randy Mah, the Director of Investor Relations. Please go ahead.

Randy Mah
Good morning and thank you for joining us today to review Capital Power's fourth quarter and year end 2021 results which we released earlier this morning. Our 2021 integrated annual report and the presentation for this conference call are posted on our website at capitalpower.com.

Joining me this morning are Brian Vaasjo, President and CEO, and Sandra Haskins, Senior Vice President, Finance, and CFO. We will start with opening comments and then open the lines to take your questions.

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

In today's discussion, we will be referring to various non-GAAP financial measures and ratios, as noted on slide 3. These measures are not defined financial measures according to GAAP and do not have standardized meanings prescribed by GAAP, and therefore, are unlikely to be comparable to similar measures used by other enterprises. These measures are provided to complement the GAAP measures which are provided in the analysis of the Company's results from Management's perspective. Reconciliations of these non-GAAP financial measures to their nearest GAAP measures are disclosed in our 2021 integrated annual report.

I will now turn the call over to Brian for his remarks starting on slide 4.

Brian Vaasjo
Thanks, Randy, and good morning. Capital Power's head office in Edmonton is located within the traditional and contemporary home of many Indigenous peoples of the Treaty 6 region and Métis Nation of Alberta Region 4. We acknowledge the diverse Indigenous communities that are located in these areas, and whose presence continues to enrich the community and our lives as we continue to learn more about the Indigenous history of the lands on which we live and work.

2021 was an excellent year in advancing our strategy and commitment to being off coal in 2023, where we saw strong progress from strategic, sustainability, and financial perspectives. At a high level, we escalated our renewables and storage footprint. We had success on long-term contracting of our renewable projects, and we made progress in repositioning Genesee 1 and 2 to be the most efficient combined cycle units in Alberta once the repowering project is completed.

Sustainability continues to be integral to our business, where we have incorporated broad compensation that is linked to our ESG targets. We have also advanced our decarbonization strategy through strategic partnerships, such as collaborating with Enbridge on a CCUS project.

Sandra will provide more details on our financial highlights. These highlights include delivering record financial performance and maintaining a strong balance sheet, and access to capital to fund our growth. We have also significantly managed down several short-term and medium-term risks to Capital Power. And based on the stability of our cash flows, we have extended our annual dividend guidance to 2025.

On slide 5 is a list of strategic highlights and accomplishments for 2021. We've enhanced the Genesee 1 and 2 repowering project with the integration of a 210-megawatt battery energy storage system, the largest in Canada. Once repositioned, Genesee 1 and 2 will have the dominant baseload position in the Alberta power market.

We executed a six-year tolling agreement extension for Arlington Valley that reaffirms our strategy of investing in strategically positioned natural gas assets. We completed the combustion turbine upgrade at Decatur that increases our contracted capacity and efficiency, which enhanced economics, consistent with the contract extension we executed in 2020.

Whitla became the largest wind facility in Alberta, at 353 megawatts when phases 2 and 3 were completed ahead of schedule in early December, and below budget. We executed 15-year renewable contracts with both Labatt Breweries and Dow Chemical to help them reach their sustainability goals through customized renewable energy solutions.

And demand for renewable contracts for us continues to be very positive. Growth in our Alberta renewable assets continues with our latest project, Halkirk 2, a 150-megawatt wind farm that is adjacent to our existing Halkirk wind facility in Central Alberta.

Lastly, we expanded our solar and storage development pipeline with the acquisition of a portfolio of solar sites with battery potential in the United States, providing us with a platform for significant renewable growth. Overall, these strategic advances support growth and our roadmap to decarbonization.

Turning to slide 6, this chart shows our growth in renewables from 2016 to 2024. Based on current growth projects, we have achieved a compound annual growth rate of 18%. As the chart illustrates, we've delivered constant annual growth where new contracted renewable projects are added every year, except for 2023, when the original completion dates for the North Carolina projects have been delayed to 2024 due to the delays in the interconnection process. We are hoping to have at least one additional renewable project to be announced this year.

Moving to slide 7, we are committed to be carbon neutral by 2050 and have a clear pathway that includes setting targets along that pathway. We have compensation elements for executives and Capital Power leaders that are directly linked to ESG targets. These include targets on diversity, a 30% carbon reduction by 2024, and employee wellbeing.

In 2021, we achieved our sustainability targets to develop company-wide water management and sustainability sourcing strategies that are designed around ESG principles to positively contribute to society and ensuring our environment can thrive over the long-term. We are moving to implement these strategies in 2022.

Our Genesee 1 and 2 repowering project continues to be on track, supporting our commitment to be off coal in 2023.

We've also incorporated sustainability into our financing by transitioning existing credit facilities to sustainability-linked credit facilities that are tied to emission intensity targets. We're advancing our Genesee 1 and 2 CCS project by collaborating with Enbridge that I'll elaborate on shortly. Through our achievements in 2021, we've increased our velocity to meet our sustainability targets and positions the Company to deliver long-term value for our stakeholders and the environment.

Turning to slide 8, we have made substantial progress on the advancement of CCUS. The CO2 hub development process is moving forward in Alberta, with the Enbridge project fitting our needs very well. We're in the process of finalizing our pre-FEED study, aimed at solidifying project definition, technology licensing, scoping, preliminary engineering, deliverables, and costing details.

We're optimistic that sufficient financial support for the $1.8 billion to $2 billion carbon capture project will come from both federal and provincial governments. We're in discussions with the Canadian Infrastructure Bank on the framework for financing. We also expect First Nations participation, as well as other potential partnerships for the project.

One of the key issues for this project to proceed is de-risking carbon policy. There's a general appreciation by governments that long-term policy uncertainty presents unique risks to investments in CCS. Our discussions with government has focused on potential mechanisms and approaches to mitigate adverse impacts in the event of carbon policy-related changes. The final investment decision is now expected in mid-2023 and is subject to satisfactory hub progress, government support, and policy risk mitigation.

I'll now turn the call over to Sandra.

Sandra Haskins
Thanks Brian. On slide 9, I'll touch on the financial highlights for 2021. As mentioned, we set an annual record for both adjusted EBITDA and AFFO in 2021, and our financial performance in 2022 is expected to be equivalent. We delivered on our eighth consecutive annual dividend increase and extended the annual dividend guidance of 5% to 2025, based on the support of predictable cash flows.

In 2021, Capital Power delivered a total shareholder return of 19%, which is consistent with the five-year average and exceeding our target TSR of 10% to 12% over the long-term. We have been de-risking our cash flows by securing low-cost carbon offsets, increasing commodity hedging, and executing on longer-term contracts to manage medium-term risks.

In June of last year, we completed a successful $288 million equity offering to pre-fund our existing growth capex. We have just renewed our NCIB program for another year that provides a capital allocation option during periods of limited growth and when the shares are undervalued. We have also extended our debt maturity profile and reduced refinancing risk.

Our investment-grade credit rating remains a top priority and the strength of our balance sheet and resilient cash flow secures our credit rating. FFO to debt in 2021 is 23% compared to S&P's target of 17%. Overall, we are well-positioned to finance our growth capex using internally generated cash flows.

Slide 10 shows year-over-year financial performance for the fourth quarter and for the full year of 2021. We delivered year-over-year increases on all key financial metrics, both in the fourth quarter and for the full year. This includes generating revenues and other income of $1.99 billion in 2021, compared to $1.937 billion in 2020.

Both adjusted EBITDA and AFFO exceeded the midpoints of our higher revised guidance. Adjusted EBITDA was $1.124 billion, an 18% increase compared to $955 million in 2020. AFFO was $605 million in 2021, a 16% increase compared to $522 million in 2020.

The positive factors that led to record performance in the year include strong performance from the Alberta commercial segment due to high Alberta power prices that averaged $102 per megawatt hour in the year. Whitla 2 began commercial operations a month earlier than scheduled in 2021, and we received full-year contributions from the additions in 2020 of Buckthorn Wind and Cardinal Point.

We accelerated the recognition of coal compensation with the Genesee 1 and 2 repowering project where we expect to be off coal by the end of 2023, six years earlier than required. We also had lower net finance expense of $23 million, largely a result of lower interest due to decreased loans and borrowings outstanding.

Offsetting the positive factors were a weaker U.S. dollar, lower wind resources at most of our wind facilities, and higher current tax expense with 2021 being our first cash-taxable year in Canada.

Turning to slide 11, I'll provide a status update on the re-contracting of our Island Generation facility. Island Generation has provided reliable power to Vancouver Island and the lower mainland of B.C. for almost 20 years. Although the facility runs infrequently, it is there and available when needed to provide reliable generation. When BC Hydro faced significant challenges in 2019 and 2021, Island Generation operated at high-capacity factors and helped to keep the lights on.

Recall that in September of 2021, BC Hydro indicated to BCUC that it needed the Island Generation facility to operate during transmission repairs. In December 2021, BC Hydro released its final IRP, where it affirmed its view that the long-term EPA for Island Generation is not required.

Based on these developments and an assumption of a four-year contract extension, a $52 million impairment was recorded in the fourth quarter. We continue to expect the need for Island Generation beyond four years and are aggressively intervening in the BCUC IRP process.

Moving to slide 12, I'll touch on the Alberta power market and our hedge positions. In 2021, we saw a full recovery in power demand from the COVID-related and low oil price load decreases in 2020. In fact, the Alberta market saw new record summer and winter peak demands. Despite not fully reopening, load remains strong today and is expected to increase modestly year-over-year. With the expiry of the Balancing Pool PPAs at the end of 2020, we saw a robust power market in 2021 with an average power price of $102 per megawatt hour, compared to $47 per megawatt hour in 2020.

The slide shows our hedge position for power and natural gas. You will note that we have increased our hedge positions for 2022 to 2024 since our disclosure at Investor Day on December 2. For 2022, we entered the year 72% hedged in the high-$60 per megawatt hour range. In 2023, we are 47% hedged in the low-$60 range, and for 2024, we are 32% hedged in the high-$50 range. This compares to forward prices of $94, $72, and $61 per megawatt for 2022 to 2024, respectively.

The hedge position includes longer-termed origination contracts as another mechanism to manage price risk and volatility. The contracts capture a lower price relative to the forwards in 2022 but reduce price risk in future years when we see prices moving down. For example, in 2022, we are 72% hedged in total, and more than 40% hedged with contracts that are greater than one year in term, many of which are three to five years or longer in duration. The long-term hedges have an average price in the low-$60 per megawatt hour range, which reflects longer-term forwards, whereas the balance of the hedge contracts are at an average price that is more in line with 2022 forwards. In 2023 and 2024, the hedges currently in place are predominantly longer-term contracts.

Natural gas prices have an increasing impact on our financial results as we transition off-coal. We have been actively hedging our expected natural gas burn for the Alberta fleet at favourable prices relative to forwards. We have hedged 100% and 99% of our expected natural gas volumes in 2022 and 2023 and have hedged 85% of our expected natural gas volumes in 2024. The average hedge price for all three years is between $2 and $2.50 per gigajoule, which is much lower than forward gas prices, as shown in the table.

Turning to slide 13, I'll conclude our remarks by reviewing our 2022 targets and comment on the various sensitivities on these targets. As highlighted, 2021 was our strongest year for financial results and 2022 results will build on this strong momentum.

For 2022, we are targeting $1.11 billion to $1.16 billion in adjusted EBITDA and $580 to $630 million in AFFO. We have looked at the impacts from rising inflation rates and have a modest unmitigated exposure on our operating results. For our growth projects, we are managing our construction exposure, which includes having over 84% of our procurement costs locked in for the Genesee repowering.

Also, with the delayed COD of the North Carolina solar projects to Q4 2024 and Halkirk 2 scheduled for late 2024, the timing will allow us to take advantage of more normal commodity and shipping costs.

To manage the expectation of higher interest rates, we have fixed rate debt in place. We have also been actively hedging the underlying GOC rates for all financings into early 2026 in anticipation of increasing rates. Financing in 2022 is limited to the refinancing of preferred shares.

2022 will be a year with significant planned outages, including outages for Genesee 1 and 3. The sustaining capex is expected to be between $105 and $115 million, which is well above the forecast of $55 to $70 million in the next few years.

Our 2022 targets also reflect our cash-taxable position in Canada. We expect continued strong internally generated cash flow based on a strong Alberta price outlook. Finally, we continue to target $500 million per year of committed capital for growth. We expect 2022 to be another very strong year, both financially and strategically.

I'll now turn the call back over to Randy.

Randy Mah
All right, thanks, Sandra. Sharice, we're ready to take questions.

Operator
The first question comes from Robert Hope with Scotiabank. Please go ahead.

Robert Hope
Good afternoon everyone. Just maybe a longer-term strategic question, just on the natural gas midlife generation side, what are you seeing out there in terms of opportunities? As you evaluate these opportunities, how does the ability to kind of reduce carbon at the sites, or co-locate renewables or batteries fit into the investment decision?

Brian Vaasjo
Good afternoon. In terms of what we're seeing on the midlife natural gas assets in terms of activity these days, it has increased significantly over the last couple of months. We're seeing a fair amount of traffic. Not the same degree of traffic that we saw pre-pandemic, but definitely more than we've seen in the last couple of years. That's looking encouraging.

When we actually are looking at a particular proposal, obviously there's a contracting side, comfort that for its economic life, it can be re-contracted out into the future, or has sufficient current long-term contract to carry us well into the 2030s. That's sort of a first hurdle.

Then we look at it in terms of, and part of our optimism around re-contracting or lack thereof, would depend on how it's strategically positioned. We've been looking at a number of assets that are just, I'll call it, simply generation assets, and create energy. But those are readily displaced by renewables and would have a relatively shorter history. Those assets that are on the grid, in strategic locations, for example those facilities that are peaking facilities, would tend to have the longest enduring value.

The other thing, because of their positioning, is it's a relatively straightforward transition to start including batteries on those sites, and then eventually retiring the natural gas facilities and having those storage capabilities realized at those sites. There's a number of things that we look at, and certainly the carbon outlook for each facility is looked at very, very closely in how it impacts on our targets. What we see is the long-term viability of that asset and that location, and so each, very much, site are project-specific. Now, we hit on all of those points when we look at the valuation as to whether we even go forward in looking at an asset.

Robert Hope

I appreciate the colour. Very helpful. Then maybe moving over to the renewables side, in the prepared remarks you mentioned that a number of the projects under development have enough time left until they're commissioned to miss some of the challenges we're seeing in the supply chains right now. For the next tranche of renewable projects, is this slowing down discussions with customers, or is the backlog of counterparties willing to backstop EPA still quite strong?

Brian Vaasjo
Well, there is a bit of a pause right now, and it's a combination of things. One, of course, is what's happening with the Biden Administration in the United States, and what's the outlook going to be for various tax credits, etc. That's creating, I think, a significant slowdown in terms of elements being transacted. Not necessarily slowing down some of the discussions, but I think before you'll see an awful lot of triggers pulled, there'll be a little bit more certainty that'll come into the market.

From a pricing perspective, you can acquire or get commitments around price out two or three years, which are tending to be a little bit lower than current pricing, or today's pricing. We expect that that will soften, and as the market becomes clearer and clearer, I think you'll see, again, a tendency for there to be more contracting taking place. I'd suggest there's a bit of a slowdown for a couple of months, but certainly by mid-year and thereafter you'll see some acceleration in renewable opportunities in the U.S.

In Canada, it's more on a province-by-province basis in terms of what's being offered by the utilities or by the provinces in terms of renewable projects. In Alberta, it continues to be the same. We see it as an excellent place to continue to invest and we've been very successful on gaining contracts on our renewable projects, even though, as we've said over and over, we're comfortable with them in a merchant perspective, but the contracting of, even on our remaining position, with the renewables at this point is very positive. Things look very good from the renewable perspective.

Robert Hope
Appreciate the colour. Thank you.

Operator
The next question comes from Maurice Choy with RBC Capital Markets. Please go ahead.

Maurice Choy
Thank you and good morning. My first question, just to pick up on the discussion on CCS. In addition to First Nations, what are you hoping other potential partners bring to the table? And a follow-up to that on timing, what could lead to an FID coming in earlier than mid-2023?

Brian Vaasjo
In terms of what would we see in a partner, we would look firstly to a strategic partner, somebody who brings more to the table than simply capital. You can see that from a technology perspective. Mitsubishi, for example, would be one. There's a number of engineering firms who are very much committed to this line of development, and in fact, do have capital that they'd like to deploy.

There's also organizations who would be very interested in continuing down investments in CCS. Enbridge, for example, would be one organization, but there are other organizations out there who are very interested in being part of, I'll call it part of the action. Then of course there's financial players who would look at it as a positive investment, given what it's achieving, but again, they would not necessarily bring anything to the table other than capital. I should be clear, we've had no discussions so far with anybody.

That brings it maybe to your second question about timing and moving forward. We see as a major date, a major milestone for us being when the federal budget comes out, and what it has in terms of magnitude and parameters around the investment tax credit. Everything we are understanding, and there's nothing set in stone or committed or anything, but it seems like that will be a positive outcome from our perspective. That's when we'll start getting into more and more discussions around specific partnerships, etc.

In terms of advancing the date in which we move forward on it, the major issue that we have right now is more around the hub process, is not advancing as quickly as we had anticipated. Initially, the expectation, and it was a broad expectation, is that the government would be looking at a number of different hubs, sort of at the same time. What's happened is that there's been an overwhelming response, and they anticipated a very, much more significant response than they expected with the first tranche. They just don't have the capacity to analyze these at the same time, so they're putting them in an order in which the Enbridge project has not come forward yet for assessment or probably more appropriately put, any of those projects that are west of Edmonton have not been asked for by the government to be assessed.

That's slowed things down by a few months. We could see that move ahead fairly quickly. We believe what Enbridge is putting forth is extremely straightforward, extremely clean, excellent, excellent project.

The other thing, though, that enters into the hub side of it is, there are some fairly significant geological expenditures to be made. It would be prudent that those expenditures take place once there's a greater degree of certainty, in terms of processes going forward. A lot of that work, we see now probably being pushed into next year and potentially being complete by mid-year next year.

Now, all of that could be advanced if there was a drive to, but as we see it, and there's still even—we could, even with the extension at the front end, it's possible to be complete in 2026. It starts pushing off to being more like reaching completion in 2027. Having said that, that's well in advance of achieving provincial and federal targets in advance of 2030. So we actually have a lot of time at the back end so don't want to do anything imprudent at the front end or get over our skis as we move forward. Pretty firm on what we need to be seeing, and things are lining up, albeit with a slight delay with those things coming to fruition.

Maurice Choy
Thanks, and that dovetails quite nicely into my next question about capital allocation. You obviously mentioned earlier that you are encouraged by the level of activity you see in the midlife gas generation market. You have this $2 billion project related to CCS, and you also mention that you may move forward with one more renewable project this year. Have you considered revisiting the potential of selling a portion of your renewables to fund all of these, noting too that you also turned off your DRIP last quarter?

Brian Vaasjo
Maybe I'll start and Sandra can certainly follow-up. Definitely, when it comes to looking at new capital requirements, I think as Sandra has said, we're sitting quite well right now, in terms of our capital requirements. But all the time, we look at turning over capital. Are there assets that we should be selling and creating liquidity events and utilizing those funds? That's always on the table. A lot of it is dependent upon our outlook for growth and the deployment of that capital and realization of that capital versus what our other alternatives are, but that's always on the table, and that's always something that's actively discussed.

Sandra Haskins
Yes, I don't have anything really to add to that at this point. When we're looking at funding our growth between internally generated cash flow and the strength of the balance sheet, we're really not in a position where we're looking at raising equity or doing a type of a sell-down. You'll remember that, of our renewable growth, a portion of that is the U.S. solar, so part of that funding will come through investment tax credits as well. At this point, we're not finding ourselves having to look at that as an option, but as Brian mentioned, it's always on the table.

Brian Vaasjo
I think one of the things maybe to bear in mind, and that's where the magnitude of the tax credit information that'll be coming out, hopefully in March, that can have a very significant impact on the net capital cost of $1.8 billion to $2 billion. Then if you take into consideration partners on top of that, it's not as daunting as it looks from a headline perspective.

Maurice Choy
That makes sense. Thank you very much.

Operator

The next question comes from Patrick Kenny with National Bank Financial. Please go ahead.

Patrick Kenny
Thank you. Good morning.

Just with the Alberta budget coming out later today, Brian, can you just remind us what else you need to see in terms of provincial government support, on top of Enbridge being awarded the sequestration rights, of course. Just more from an economic perspective, what provincial clarity or policy milestones should we be watching out for?

Brian Vaasjo
Certainly, there can be surprises, whether it be federal or provincial governments that create problems for us moving forward. We don't anticipate any or we're not thinking of any, but that's always a possibility.

From what we see and what we kind of understand, from a pure financial perspective, we are anticipating that between the support from the Canadian Infrastructure Bank, the investment tax credit that we believe might be available to us, we don't think there's much more needed from a "financial perspective."

What is important though at this juncture, and what we need to see, is some de-risking of the carbon credit environment, whether that be in the form of contract for differences, whether that be in the form of other different kinds of instruments that create some higher degree of certainty around that cash flow. As I indicated, it seems like the governments are very much aware of it, they understand, and I think as the banking community also represents, that's a very, very significant and a bit of an extraordinary risk for the magnitude of the investments that are being made, so we believe the governments are sympathetic.

What that translates into and whether it's from the federal perspective or from the provincial perspective, we're talking to both governments about the need for something and talked a little bit about some mechanisms that we think might work and do believe it's in active discussion, at least from a federal perspective.

We don't see that it should come out in terms of regulation. We have a bit of a challenge with anything, if it's a regulation and you're hoping that it stays pat for 20 years, that's not necessarily the case. We would actually be looking for something that would be contractual as opposed to regulatory, to provide that extra degree of comfort. Much like what was our insistence with the Alberta provincial government in negotiating the off-coal arrangements, weren't satisfied with it being in regulation, needed to be by contract. We see the same sort of approach from the greater assurance from the carbon risk perspective.

Patrick Kenny
Okay, great, thanks for that. That's helpful. Maybe for Sandra, the 72% hedged position for this year in the high-$60 range versus, I guess forward prices still in the mid-90s. Is that relatively higher percentage of baseload sold forward more of a function of being able to lock in your natural gas requirements below market, or is it perhaps more reflective of a view that you think the forward curve doesn't reflect reality and that, as we get into the peak summer months, you would expect spot prices to settle much lower?

Sandra Haskins
It's sort of a combination of things. Firstly, when you're looking at that 72%, over 40% in total of the 100% of baseload are long-duration contracts. Some of those are quite far out, and that was done intentionally when we realized we were in a period of very high prices in '21 and '22, but with supply coming on in a couple years, we expect those prices to come down.

Given the amount of incremental length that we have with the Genesee 1 and 2, it was prudent, in our perspective, to take on those longer-term contracts and lock in that length. When you're looking at just the hedging for 2022 only contracts, we're only 32% hedged, and that's in the low-$80 per megawatt hour range.

You have to appreciate that, as we step into hedge positions, over time the forward price has sort of moved up to where it is now in the high-$90s. We continue to look at hedges of the book, but what's really driving that relatively higher hedge position are the longer-term duration contracts that do have a lower price. They would be contracted at a level that would be more representative of the long-term forwards versus the current year forwards.

Patrick Kenny
Okay, that makes sense. Thank you. Last one for me, just curious if you're experiencing any inflationary pressures on your maintenance activities, or if you've been able to mitigate the risk around your sustaining capex guidance for the year? Then also maybe you could just dovetail in a quick comment on how we should be thinking about your O&M in general, just across your entire contracted fleet, elsewhere, outside of Alberta?

Sandra Haskins
Yes, so what we see… Oh, go ahead, Brian.

Brian Vaasjo
No, go ahead, Sandra.

Sandra Haskins
I was going to say, on the maintenance side, our LTSAs are quite insulated from the impacts of inflation, so we are seeing that we don't have a lot of risk from that perspective. All in all, we see a fairly mitigated exposure to inflation overall.

Brian Vaasjo
I was going to add that how we see the operating maintenance costs line up for this year and beyond is, with a lot of the work that we've done last year and some of the work we're anticipating doing this year, it actually positions us for a lower spend. We see that as being positive, and I think we went through that during our Investor Day.

In terms of inflation, a lot of the activities associated with outages and just ongoing maintenance activity is labour-related. It more is driven by what are the union contracts, and also the availability of labour, as we move forward in the various regions. That's a very significant component of our costs and we don't see that—although rising, we don't see it getting too far out of control, not like what we've seen on steel prices and other things that have gone up quite a bit, but of course, they're coming down right now as we speak. So, do not expect inflation to have a significant impact on our costs going forward.

Patrick Kenny
Okay, that's great. Thank you.

Operator
The next question comes from John Mould with TD Securities. Please go ahead.

John Mould
Hi everybody, thanks for taking my question. Really just, I guess, one broad one on the carbon side, as we're going through some fairly large policy reviews, I think, over the next few months. I'm just wondering what your current base case assumptions are for Alberta specifically on the TIER review and how you expect or how you think that might unfold in the context of the federal backstop as it's currently constituted?

Then, how you're thinking about the clean electricity standard more broadly, and I appreciate we don't have that policy yet, but I think we've got the contours at least. Including in Ontario, outside of the assets where—on Genesee, specifically, I guess, where you're looking at significant carbon abatement. Can you maybe just tackle those two bigger picture topics?

Brian Vaasjo
I think from an Alberta perspective, what we see is the Alberta government very much committed to continue with the TIER process, i.e. having its own regime. As it moves forward with negotiating those agreements with the federal government, of course, needs to be aware of and so on, of whatever changing federal policies there may be around carbon and various standards.

We do believe that the Alberta government sees that the current intensity, the 0.37 is where it should be and would endeavour to be maintaining that through to 2030. Again, we'll see when it comes to discussions and negotiations, but we see, and it goes to an earlier question, we do see that the Alberta price for carbon will keep lockstep with what happens from a federal perspective. That's one element of negotiation and commonality between the federal backstop and what we would see in Alberta.

The biggest issue, of course, is what happens in regards to the oil and gas industry. From that perspective, not sure what's going to happen there, and again, that's where there'll be, we believe, the focus of discussions.

From an Ontario perspective, in Ontario, our assets, generally the implications of carbon tend to be borne by the ISO who is a counterparty on the contract. It's not perfect in terms of being perfectly covered, but I think in all material respects, it's generally covered there.

The interesting thing about an escalating carbon price is that, depending on where your asset is in the queue and how efficient it is, it generally drives less efficient assets, are dispatched less, and more efficient assets, of course, are dispatched more. What we see in Alberta and what we are expecting in other jurisdictions is that as there may be escalating carbon prices, generally our assets are called on more as opposed to less. We don't necessarily see escalating carbon prices as being negative as we move forward.

John Mould
Okay. I will leave it there. Thanks very much for that detail.

Operator
The next question comes from Andrew Kuske with Credit Suisse. Please go ahead.

Andrew Kuske
Thanks. Good morning. I think in your slide deck, you had language around Island stating an intent to aggressively intervene in the BCUC process. I guess, is there just a bigger picture issue with the way that BC Hydro's behaved in relation to Island that, the bigger issue is really Powerex's marketing license? If there's not a functional market within British Columbia, doesn't that create a bigger problem? Is the question really, you ultimately probably want to put some fair resolution of this?

Brian Vaasjo
Not really fully aware of all of BC Hydro's motivations and how much Powerex plays into it, and Powerex considerations. Right now they do have a definitive need for a greater security on the Island because of the work they're going to be doing on the transmission lines. Again, the work they do is not actually going to increase the capacity, it's just going to be increasing the reliability. Again, not sure if it's actually going to solve the Island problems.

Our biggest challenge, I would say, has been that, what we have gone through, and if you look back at the previous IRP and the one before that, there has tended to be a lot more information, a lot more disclosure around just the underlying data that transmission experts could look at and analyze, and either agree or disagree.

What we've substantially gone on is the fact that we've been dispatched pretty regularly. There's been no increase in capacity. There's an increase in demand on the Island. Everything points to not only the historical need being there, but an enhanced need going forward. It's the lack of data, the lack of transparency that has been our problem thus far.

Now, we expect to overcome that through the BCUC process, through information requests and so on. We should be able to get at that data and determine whether or not we think it's, well bluntly right now, we think they're planning, they've got a degree of brownouts on the Island that they believe is acceptable. We don't see that there's any other logical answer to that situation, but obviously they're not disclosing that publicly to any great degree.

Andrew Kuske
Okay, that's very helpful context on things. Then, the second question is really around, historically, your construction expertise has been quite favourable, and you've managed to deliver a number of projects with tight timelines and within budget, in part because of the construction expertise. How do you look at that as a competitive advantage going forward, and can you scale it if you wanted to deploy more capital into the market, or do you feel you're in the right kind of spot right now for building new things?

Brian Vaasjo
It depends. That all depends on the new things that you're referring to. When it comes to, so for example, with the repowering that's taking place now, and we don't talk about it a lot, but for example where we are now on that project in one year is typically where organizations are in two

years. We compressed the front end of that project considerably and we are meeting our milestones. I think it creates that ability to move quite quickly through construction. On a major project, that takes a lot of effort out of the organization, with the repowering.

If you're looking at a wind farm or a solar facility, we do and continue to do things a bit differently than many others. What we learn, or what we developed with one solar facility, or one wind facility, we're able to apply that, just as part of the way we do things. Our ability to build a significant number of wind or solar facilities is definitely there. We can greatly expand from a couple a year to a handful, to again, in time, much beyond that. From a renewable perspective, I think we have great, great capacity to build, at the same time, a number of facilities.

Andrew Kuske
Thanks, Brian. That's very helpful.

Operator
The next question comes from Mark Jarvi with CIBC Capital Markets. Please go ahead.

Mark Jarvi
Thanks everyone. Maybe just coming back to the carbon and capture storage project. You talked about Canadian Infrastructure Bank, First Nations involvement, strategics. Just wondering, how low a percentage could you be? Is there a minimum that you want to be in terms of economic participation, and at the same time, is there sort of a sweet spot in terms of a specific target you're looking for in terms of ownership?

Brian Vaasjo
I would say unless there's extraordinary circumstances, I think we'd want to retain at least 50% of the project. I think that would be the line that we would start off looking at partners, and out of that, of course, would come First Nations.

But for example, if there was a 10% interest by the First Nations, maybe the other two partners at 45%, ourselves and somebody else at 45% each, a lot will just depend on governance and other issues that drive that, but somewhere around 50% would probably be the sweet spot.

Mark Jarvi
When you're saying 50%, are you thinking the Canadian Infrastructure Bank is providing sort of a loan, and therefore it's sort of the net, the loan from Canadian Infrastructure Bank, or how do we think about that part of the capital contribution?

Brian Vaasjo
No, I'm speaking more in terms of just, if you look at what an ownership interest of Capital Power would be, in the order of, somewhere in the zone of, I would say 50%. In terms of Canadian Infrastructure Bank, they have guidelines and direction and what they would be potentially willing to support or fund, which would not be the entire, I'll call it debt cheque for the project.

Of course, any funding associated with First Nations would be coming out of other areas of the federal or provincial government. There'd definitely be a need for public debt financing on the project. There may well be project financing associated with it, again, depending on partners and approach, you'd probably see a combination of Canadian Infrastructure Bank support plus more traditional debt.

Mark Jarvi
Then just coming back to the Enbridge hub, it seems that you still think that's going to go through, but if for some reason it didn't, what's Plan B then, in terms of that component?

Brian Vaasjo
The issue is finding the appropriate geological site. For example, I would say right now, if Enbridge decided for whatever strategic reason or whatever, to not move forward and there was no technical reason, there was a problem with the site, we'd just take it over. It's relatively small compared to the CCS investment that we're looking at. We'd just take it over and either look for somebody, one of the other pipeline organizations that would be happy to take it on, or, again, do it ourselves.

If it was a technical reason, and that technical reason being more geological, we'd look quickly for an additional geological site that was relatively close at hand. The Alberta geology is blessed with a lot of potential for space, so don't believe that that would be necessarily a huge problem.

Mark Jarvi
Okay. Then one last question, just on the gas hedges. You are highly hedged for your baseload. If you did have an unplanned outage like you saw at Genesee, what risk, or how would you deal with that? Could you just use the gas out of a sort of dispatchable facility? Would you just resell the gas? Just thinking of any risks around being highly hedged on the gas side.

Sandra Haskins
Yes, we would be able to sell the gas or redeploy it, so very minimal risk there given the contract price that we have for those contracts.

Mark Jarvi
Did you do that in the past here, given the Genesee 2 outage?

Sandra Haskins
At times there would've been some shape to it, so yes, there would've been some opportunity to lay some of that off, for sure. Yes.

Mark Jarvi
Generally, do you net out positive on those?

Sandra Haskins
Correct.

Mark Jarvi
Or is there something… Yes, okay, perfect. Thanks, everyone.

Operator
The next question comes from Naji Baydoun with iA Capital Markets. Please go ahead.

Naji Baydoun
Hi, just a couple of questions starting with the Genesee CCS project. It seems like, clearly, that's the next phase of the evolution of Capital Power. I'm just wondering, if that project doesn't move ahead or if it has to be materially altered, what are some different options that you're thinking about in terms of other capital allocation priorities? You touched a bit on M&A, but maybe a bit more colour on that and more detail around organic growth would be helpful.

Brian Vaasjo
As we look at that project, obviously if it moved forward, it would have a bit of an impact of limiting what else Capital Power could do. We still could have a significant growth in renewables and acquisitions over that time period, but certainly it would decrease the overall appetite.

What I'd say is that we would continue to look at growth in renewables. We'd see potentially some additional natural gas acquisitions, although we're seeing a lot of activity now and we expect a lot of activity next year.

We do expect that, in time, those opportunities, and when you think of midlife natural gas assets with significant contracts associated with them, those are going to become fewer and farther between, so don't anticipate, say, in the last part of this decade, you'd see a lot of activity on that front, more so in the early part of this decade. You would see a lot of the growth, if not in some years, all the growth coming from renewables.

Naji Baydoun
Okay, that's very helpful. Just maybe tied to your previous comments on competitive edge with the Genesee repowering, I suppose you're not really considering acquiring other thermal assets and applying that same experience and knowledge to transition them to more efficient or lower carbon assets?

Brian Vaasjo
That's certainly something to think about in the future, and I would say, a couple years from now with some success with Genesee or at least moving well down the road, that may be something to look at. Certainly, in the United States, there's a growing recognition of the need for CCUS. We see there may be some of those kinds of opportunities that might open up for us, where we might apply expertise to a relatively new natural gas facility, and again, in the U.S.

Even in Alberta when we look at it, and we look at Genesee 3, we would anticipate, at some time, it would make sense to potentially repower it and apply CCUS, particularly when the new infrastructure is in place. There are those kinds of opportunities that may be out there.

We, at this point, aren’t seeing that as, other than the Genesee 3, we’re not seeing that as something that’s kind of on the radar screen, but it definitely has some potential in the future.

Naji Baydoun
Okay, that’s it. Thank you.

Operator
This concludes the question-and-answer session. I would like to turn the conference back over to Mr. Randy Mah for any closing remarks.

Randy Mah
Okay, if there are no more questions, we will conclude our conference call. Thank you for joining us today and for your interest in Capital Power. Have a good day everyone.

Operator
This concludes today’s conference call. You may disconnect your lines. Thank you for participating and have a pleasant day.