Capital Power
Q1 2024 Results Conference Call
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Operator
Good day and thank you for standing by. Welcome to the Capital Power Q1 2024 Analyst Conference Call. (Operator Instructions)

Please be advised today's conference is being recorded.

I would now like to turn the call over to our speaker today, Roy Arthur.

Please go ahead.

Roy Arthur
Thank you, Kevin. Good morning and thank you for joining us today to review Capital Power's first quarter 2024 results which we released earlier.

Our first quarter report and presentation for this conference call are posted on our website at capitalpower.com.

Leading today's call we have Avik Dey, President and CEO, along with Sandra Haskins, our SVP, Finance and CFO. Avik will commence with a high-level update of our overall business, followed by Sandra, who will delve into the financial highlights of the quarter. After Avik's closing remarks, we will welcome questions from the analysts as part of Q&A.

Before I start, I'd like to remind everyone that certain statements about future events made on the 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 of forward-looking information on Slide 3 or our regulatory filings available on SEDAR.

In today's discussion, we will be referring to various non-GAAP financial measures and ratios also noted on the disclosure. These measures are not defined financial measures according to GAAP and do not have standardized meanings prescribed by GAAP and therefore, unlikely to be comparable to other similar measures used by other enterprises.

The measures are provided to complement the GAAP measures, which are included in the analysis of the company's MD&A.

Reconciliations of non-GAAP financial measures to the nearest GAAP measure can be found in the 2023 Integrated Annual Report.

I would like to acknowledge that Capital Power's head office in Edmonton is located within the traditional and contemporary home with many Indigenous peoples of the Treaty 6 region in the Met Nation of Alberta, Region 4.

We acknowledge the diverse Indigenous communities that are in these areas presence continues to enrich the community and our lives as we learn more about the indigenous history of the land in which we live and work.

With that, I will turn it over to Avik for his remarks.

Avik Dey
Thanks, Roy, and good morning, everyone.

During the first quarter of 2024, while we experienced some challenges in our Alberta commercial business, we also achieved some notable wins across our three strategic areas of focus as we continue our journey to power change by changing power.

From a delivering reliable and affordable power standpoint, we generated nine terawatt hours of power across our strategically positioned fleet of assets.

We closed two significant and diversifying transactions that reposition us as a leading North American IPP. And from an operational standpoint, we made a significant amount of investment in our existing assets across our fleet with seven turnarounds for a total of $34 million of capital spend, consistent with our budget for the year.

When it comes to building new generation, we have achieved a significant milestone as we are commissioning simple cycle at Unit 1 of the Genesee complex, which takes the unit off coal.

In total, we are advancing 560 megawatts of incremental capacity on development projects across our portfolio.

Lastly, we continue to pursue the creation of end-to-end solutions for our wholesale customers.

For example, in January, we announced we entered into an agreement to jointly assess the development and deployment of grid scale small modular reactors, otherwise known as SMRs, with Ontario Power Generation to provide clean, reliable nuclear energy for Alberta.

Moving on, we would like to provide an update with respect to our Genesee Repowering project. Page 6 lays out an overview of the 3-stage process to implement the repowering.

As I mentioned, for Unit 1, we are now in the process of commissioning simple cycle.

During the commissioning phase, unit dispatch will be driven by project needs rather than the economics, meaning that simple cycle output will range between 0 and 411 megawatts.

For Unit 2, we anticipate commissioning to begin in the second quarter for completion in Q3.

Simple cycle commissioning is an important milestone as it marks that we are 100% off coal.

In the fourth quarter, we aim to commission combined cycle on both Unit 1 and 2.

Finally, in the first half of next year, we anticipate ramping both units up to 566 megawatts each, bringing us to the end of the Genesee Repowering project.

As we move through each subsequent stage, our carbon intensity will continue to decline, which at completion will be 0.36 tons of CO_2 per megawatt hour, representing a 60% drop from our legacy units, making Genesee the most efficient combined cycle units in Canada.

From a cost perspective, we are updating our estimated cost range to $1.55 billion to $1.65 billion, up from $1.35 billion previously indicated. The change in cost is driven by increased costs related to outages required for tie-in and ongoing productivity challenges.

Inclusive of the cost increases, the project continues to generate returns that exceed our equity return hurdles. Despite the challenges associated with the project timeline and costs, we remain very proud of our work on the Genesee Repowering project. Allow me to provide you three key reasons why.

Firstly, from a Capital Power perspective, this advances us towards our strategic areas of focus, providing reliable, affordable and clean power.

Additionally, the project represents the single largest decrease in emissions among any project we have undertaken, while generating attractive returns.

Secondly, from an industry perspective, this project is leading the way in resetting the regional power merit curve prompting retirement of older generating units and investments in more efficient generation. The result is a larger, more efficient, flexible natural gas supply that supports greater renewable capacity than would otherwise be possible while maintaining grid reliability.

Lastly, from a consumer perspective, this represents the largest decarbonization event in Alberta's history and is a testament to this province and the energy-only markets ability to lead with respect to decarbonization of carbon intensive industries.

Ultimately, it cements our position as a leading power producer in a key Canadian growth market and provides a foundation that will fund our future growth, optimization and diversification efforts across our portfolio.

During the first quarter, we closed two acquisitions that we announced in November of last year.

As we have indicated in the past, we are focused on core markets with strong fundamentals and a commitment to decarbonization. California and Arizona are great examples of this where the long-term outlook for these assets remains quite strong.

In California, we are seeing strong capacity pricing out towards the end of the decade, which reinforces our thesis for acquiring flexible natural gas generation assets.

Our Q1 results already reflect the increased diversification from the newly acquired assets despite not providing a full quarter contribution.

As shown on the pie chart at the bottom left of Page 8, our U.S. business represented a third of our EBITDA for Q1 2024 in contrast to approximately 16% in the same period in 2023. Given our pro forma capacity is now weighted 50-50 in Canada and U.S., we expect to see this contribution increase further during the remainder of the year.

As we move forward, we will provide more updates regarding the re-contracting of these assets.

In addition to Genesee repowering, we wanted to briefly touch on some of our other major projects. Regarding CCS, after a detailed review of the project, we have concluded that the economics for CCS at the Genesee site do not meet our targeted risk return thresholds.

As such, we are discontinuing pursuit of the $2.4 billion Genesee CCS project.

However, we do view CCS technology as being viable.

This is a result of our thorough work including extensive technical review of the post-combustion CCS value chain from capture through sequestration including types of solvent and components that can optimize the process.

A lot of the learnings here are applicable to CCS anywhere. So we will continue to evaluate potential CCS projects. Notably, through a grant awarded by the Michigan Public Service Commission, we are conducting a CCS feasibility study at Midland Cogeneration, the largest natural gas-fired combined electrical energy and steam energy generating plant in the U.S.

In Ontario, we announced a meaningful and positive update with respect to the anticipated capital cost of our projects we are pursuing there.

Our project capital cost will be about $600 million combined for our East Windsor Expansion and Battery Storage projects at York and Goreway.

At this time, we do not anticipate any changes to the timing of completion for these projects.

Lastly, on the renewables front, Halkirk 2 Wind and Maple Leaf Solar remain on schedule.

With respect to how Halkirk 2 Wind, we recently announced we have signed a virtual power purchase agreement with Saputo Inc., meaning this asset is essentially fully contracted.

Overall, we are encouraged by the progress we've been able to make across our strategic areas of focus.

Since the announcement in March at the IPPSA conference, we have received a number of questions regarding the proposed regulatory changes in Alberta, and we would like to address them now.

There were two proposed changes announced. One, the MSA's interim rules set to take effect July 1st of this year; and two, the AESO's proposed restructured energy market set to take effect post the expiry of the interim rules.

Regarding the interim rules, this consists of market power mitigation, meaning an offer cap after a reference unit is deemed to have reached a predefined return threshold and a supply cushion mechanism, which allows the AESO to compel long lead time units to be online and available for dispatch.

Broadly speaking, we understand and remain supportive of the interim rules as we believe these provide a circuit breaker that can provide peace of mind for Albertans with respect to the price and reliability of power.

In our view, the interim rules do not represent a significant change to the near-to medium-term pricing outlook given the 2 gigawatts of incremental supply that is coming online in 2024 in Alberta.

Regarding the restructured energy market as an independent power producer, we're making significant long-term investments in Alberta's energy future. And so the details of the restructured electricity market will be critical. As such, we will be proactively engaging in consultation with a focus on the REM.

However, I would like to point out that we were highly encouraged by Minister Neudorf's remarks at the IPPSA conference in March, where he expressed a commitment to the energy-only market and the importance of providing investor certainty.

I will now hand it over to Sandra to provide a financial update.

Sandra Haskins
Thank you, Avik. Adjusted EBITDA was 30% lower year-over-year, mainly due to the lower contributions from Alberta commercial, which I will speak to in more detail later. The full recognition of the off-coal compensation from the province of Alberta in 2023 and onetime fees in the current quarter related to the U.S. acquisitions also reduced 2024 reported results compared to the same period last year.

In contrast, adjusted EBITDA benefited from strong contributions from the recent acquisitions of Fredrickson 1, La Paloma, and Harquahala. AFFO for Q1 2024 was lower than the corresponding period in 2023 due to lower adjusted EBITDA, net of taxes and higher sustaining CapEx and maintenance compared to the same period last year.

On Slide 12, we have provided a breakdown of our quarterly adjusted EBITDA by region.

The largest relative and absolute impacts were in Alberta commercial, where lower realized power pricing, combined with decreased generation including unplanned outages at G1 and G2 and longer outages at Clover Bar Energy Centre led to lower adjusted EBITDA in 2024.

The Genesee outages, while short in duration, occurred during high-price periods. The U.S. facilities had a $39 million increase from the addition of newly acquired assets with the contribution from our legacy assets at $73 million in Q1 2024 being essentially flat year-over-year.

The contracted Ontario and Western Canada assets have the same year-over-year stable results with outages at Quality Wind and Whitla Wind combined with lower wind resource contributing to the modestly lower adjusted EBITDA for Q1.

Essentially, we are seeing benefits to our diversification efforts through the reduced adjusted EBITDA volatility from our portfolio outside of Alberta commercial.

On Slide 13, we have provided additional details on the year-over-year change in adjusted EBITDA from the Alberta commercial portfolio for the first quarter.

As indicated in our guidance presentation in January, a material decrease in the contribution from the Alberta portfolio was expected throughout 2024 due to the lower forward prices and forecasted lower generation during the Genesee Repowering project commissioning schedule.

The waterfall shows the Q1 decrease assumed in our annual guidance on the first step change. Mild weather and strong renewable generation further decreased Alberta power prices, which had an estimated incremental negative impact shown on the next step in the graph.

The first fire of simple cycle commissioning for Unit 1 began on April 7, which was later than forecast and resulted in lower generation in Q1, as shown on the next step, while the last step reflects the impact of the outages at CBEC 3 and the more frequent intermittent forced outages that were experienced on the existing aging Genesee units as they approach their end of life.

These latter impacts are a function of repowering and extended outage intervals at Genesee that are not consistent with our standard operating performance.

With the completion of repowering, we anticipate the return to our historically high standard of reliability and predictability of cash flows.

I'll now touch on our Alberta power and natural gas hedge positions for 2025 through 2027, which are shown as of March 31, 2024.

For 2025, we have 9,500 gigawatt hours hedged, while in 2026 and 2027, we have 8,500 and 5,000 gigawatt hours hedged, respectively.

The weighted average hedged prices are in the high $70 per megawatt hour for 2025 and 2026, while 2027 is in the low $80 per megawatt hour. This compares favourably to the forward prices of $56 per megawatt hour in 2025 and 2026 and $60 per megawatt hour in 2027.

The hedge positions include long-duration origination contracts as shown on the graph on the left.

Our natural gas hedge volumes remained significant for 2025 and 2026 at 60,000 TJs and 35,000 TJs in 2027.

Our prudent hedging strategy over the past few years, while in a backward dated market, provides downside price protection and stability of cash flows as we move into a full supply (technical difficulties). The Q1 results and the outlook for the balance of 2024 has adjusted EBITDA trending to be less than 5% below the lower end of the guidance range of $1.450 billion to $1.505 billion.

AFFO is expected to come in below the midpoint of the guidance range due to the tax-affected adjusted EBITDA variance and incremental favourable current income tax from the accelerated depreciation treatment on the Genesee Repowering project.

While the Alberta commercial performance is disproportionately exposed to Q1, there remains an element of uncertainty on price and volume variances, which are influenced by commissioning activity.

As a result, we are not providing revised guidance ranges for this quarter.

As we move through Q2 and Genesee commissioning, we expect to have a better line of sight to provide guidance for the balance of 2024, which is a transitional year for Capital Power.

With that, I will now hand it back over to Avik.

Avik Dey
Thank you, Sandra.

We remain steadfast in our focus to deliver reliable and affordable power today while building clean power systems for tomorrow and creating balanced energy solutions to our wholesale customers.

To that end, we are excited about our upcoming Investor Day in Edmonton on May 7th and 8th, where we will talk about this journey in more detail. This two-day experience for institutional investors and research analysts will involve a tour of the Genesee Generating Station site and our massive Repowering project in addition to a formal presentation in the morning of the second day.

We look forward to welcoming you to Edmonton.

With that, I'll now turn the call back over to Roy.

Roy Arthur
Thanks, Avik.

Operator, with the conclusion of the opening comments, we are now ready to take questions.

Operator
(Operator instructions)
Our first question comes from David Quezada with Raymond James.

David Quezada
Thanks, good morning everyone. Maybe I'll just start, Avik, with your comments just around the Alberta market design or restructuring happening there. I'm just curious if you've had any initial talks with the government just in terms of engaging with them on that topic? Or what kind of timing you would expect for that, and maybe if you could just quickly outline what do you think the initial priorities would be near term?

Avik Dey
Thanks for the question, David. And in terms of priorities, you're referring to priorities on the restructured electricity market?

David Quezada
Yes, correct.

Avik Dey
Okay, so the first part of your question, yes, we've been actively engaged. Frankly, we've been engaged throughout the course of the last year leading up to the announcement and continue to do so post IPPSA.

In terms of the restructured electricity market proposals, as we said in the comments, we are highly supportive of Minister Neudorf's comments.

In terms of preserving the energy-only market and providing the necessary tweaks to ensure reliability, affordability and increase a further investment in generation, I think as it relates to the AESO and MSA reports, we think structurally, there's some inconsistencies in those reports related to preserving an energy-only market, but we take a lot of confidence in the consultation period that's commenced.

We've already had a few meetings within that consultation phase with industry participants and the AESO and we look forward to engaging.

In terms of timeline, as the Minister noted on March 11, we have a period between now and the interim measures rolling off by 2027 to determine what the ultimate structure changes are.

But we remain focused on the Minister's comments of preserving an energy-only market and expect that to be the case.

David Quezada
Excellent, thank you I appreciate the colour. Maybe just one more for me just on the theme of sort of, it feels like a lot of momentum around growing demand for electricity, particularly in the U.S. and obviously you guys are increasingly well positioned there.

I'm curious, do you see any opportunities given the PPAs you have in place across your current footprint in the U.S. and could you look to turn your sights to additional M&A? And maybe any thoughts you might have on the M&A market for natural gas power plants today?

Avik Dey
Thanks for the question. With regard to growth opportunities in the U.S. in particular, stemming from multiple sources of load growth demand, we are seeing opportunities across our existing generation fleet and outside to whether it's expand, contract, or joint venture with others to participate in that growing load growth.

Nothing is imminent as we sit here today, but a number of positive conversations. And I think our generation fleet, particularly between the Northwest California and Arizona is particularly well positioned to participate in any potential growth. So yes, we're excited about the opportunity there.

We'll be talking a lot more about this next week at our Investor Day. I don't want to steal all of the thunder from that conversation. But we see significant opportunity there aligned with what many of the U.S. IPPs are seeing. And we think our positioning is relatively strong compared to those companies, given the fact that we've been in traditional natural gas generation for the past 15 years and really focused on optimizing these assets, decarbonizing them and enhancing them while still having the capability to trade and originate, which is unique amongst the U.S. IPP space.

With regard to M&A, as we've seen over the past year, we continue to see significant M&A activity. We're seeing more and more financial players come to the table participating in these processes and auctions, which I think is a leading indicator to where the market is going in its expectation of load growth and merchant plants or just generation overall participation in the supply stack.

On the strategic side, we're not seeing as many strategic players come to the table, but we're optimistic about the outlook there.

In terms of our own activity on M&A, to date, we've been focused on integrating our existing assets. And so, I would expect second half of this year we'll continue to look at opportunities that fit with our strategy.

David Quezada
Very helpful, thanks Avik I'll turn it over.

Operator
Our next question comes from Robert Hope with Scotiabank.

Robert Hope
Two questions on Alberta, the first one is, how are you thinking about allocating capital moving forward? Just given the uncertainty of what the rules will look like in 2027, how do you think about incremental investments in Alberta beyond the repowering? Could it be more focused on renewables that are

backed by contracts to mitigate some of the merchant power risk?

Avik Dey
Thanks for the question, Rob. With regard to capital allocation, as noted with our activity last year, we've been pretty heavily focused on expanding our footprint in the U.S. We're a preeminent producer of power in Alberta, we've got core assets in the province and with the announcement of us evaluating SMRs in Alberta with OPG, we think we've got our line of sight towards long-term generation capacity.

We don't see a need for new firm dispatchable capacity in Alberta for the next 10 years. So from a capital allocation perspective, you could expect our capital to be directed towards U.S. opportunities more than Alberta.

In terms of Alberta, to answer your question very specifically, we do not intend, in the short term, to allocate more capital towards new renewable projects or new mid-merit natural gas assets in Alberta.

Robert Hope
Thanks for that. And then another question on Alberta and maybe diving into the nitty gritty of it a little bit. With the interim rules in place with the potential that it mitigates upward volatility in pricing, does that alter your trading strategies in the province? Or could it lead you to, if pricing was what you wanted it to be to more fully contract your merchant exposure there?

Sandra Haskins
Thanks, Rob, it's Sandra. Yes. I would say that what we're expecting in the Alberta market right now for the balance of the year is a reversion back to what we would have seen pre the volatile market over the last couple of years. And during that period of time, we had a hedging strategy that we would look to put hedges in place as we saw opportunities to hedge above our expectation of price and don't see that changing. We do sort of see just a reversion back more to the norm. And as you know we do have a number of longer-dated hedges that have reduced the amount of open exposure we have in any given year.

So, from our perspective, we'll continue to layer in hedges as we see the opportunity to do so. So no real change from a hedging strategy perspective, but do expect that we're going to see a more stable, less volatile price environment going forward for the next number of years given mostly the attributed to the supply additions that are coming online more so than rule changes.

Operator
Our next question comes from Ben Pham with BMO.

Benjamin Pham
Good morning. I know you mentioned in your last remarks to Rob around capital allocation, not interested in Alberta on a go-forward basis. Is the thinking then next that you're comfortable with your current portfolio in Alberta? Or would you be more proactive of perhaps looking at JVs or asset sales in the province? Just to become maybe more of a U.S. IPP.

Avik Dey
Thanks for the question, Ben. I wouldn't say we're not interested in Alberta. But I think given our significant position where it constitutes 30% of our EBITDA currently, we like the concentration that we have in Alberta.

We want to maintain and optimize our existing position. We've got what will be the largest and most efficient gas plant in the country and an important provider of a baseload generation in the province.

But with regard to the second part of your question, I think we're always looking at ways to optimize the portfolio, and we'll continue to do so. As Sandra stated in previous quarters, we are looking at asset recycling opportunities across our portfolio. And I think what you will see from us going forward is a very refined focus on how do we optimize return on capital employed and optimize return to shareholders through equity returns.

So I would characterize our position in Alberta as optimizing and it also recognizes the fact that we are 2-gigawatts oversupplied in the market. So, I think that's the most important point, which is over the course of the next 10 years, we do not see the need for incremental dispatchable firm capacity in the province.

That's not tied to the March 11 statements on market structure, that's in line with our view coming into 2024 where we were adding this incremental supply.

Just to summarize because I do think this is a really important point, we want to optimize Alberta, we'll continue to look at asset recycling.

We're not looking to deploy new capital into the province currently, but remain focused and steadfast in the medium-to long-term outlook subject to maintaining the energy-only market.

Benjamin Pham
Thanks for clarifying that. And maybe on slide 13, maybe this is for you Sandra, you've highlighted the walk on Alberta commercial year-over-year. These four buckets you've highlighted, can you clarify what was actually in your guidance? Because this is a walk year-over-year versus a change versus your January guidance?

Sandra Haskins
Thanks, Ben. Yes, you're correct. It's a bit of a mix between the guidance as well as year-over-year. And what the slide is intended to portray is the amount of year-over-year decrease that was normal course or expected coming into the year, and that's the first bucket where we had anticipated lower prices in Alberta compared to what we captured Q1 last year as well as less generation overall as we go through the Repowering project.

So, having set that element aside, we then focused in on where the quarter went post that expectation just to sort of make the current quarter performance from the year-over-year normal course reduction. And so, when you look at the lower prices, primarily driven by lower volatility in Q1, and as you know we typically see winter peaking in Q1 of the year with a lot of volatility driving higher prices. And if those price escalations where you're able to capture value above our base load hedging.

As we were quite highly hedged even with the flattening of prices, the incremental impact of that was only about $14 million, which is less of an impact on prices relative to the overall step-down that we saw or expected coming into the year based on forwards.

We also have the delay on simple cycle 1 commissioning. So as we have been stating all along that the predictability of the exact timing of first fire and closing of commissioning on a simple cycle unit as well as what hours the unit will actually run during that period of time is driven by the project and not economically driven.

So, coming into the year, we had expected that first fire could occur in Q1 and during that period of time, we would have had generation off of the commissioning unit as well as the base unit. Given that repowering did not hit that first fire until outside of the quarter, we did see reduced generation from the commissioning units that we had anticipated.

So that's been pushed into Q2 as opposed to realized in the quarter.

The other part is the outages that we saw at Clover Bar 3, which is currently in an outage that was expected to end in Q1. It's now expected to come back online in Q3, and therefore, when we did see periods of higher prices or outages at Genesee 1 and 2, that unit was not there as it typically would be for backstop.

We also saw a number of forced outage hours at Genesee 1 and 2. So as you recall in our guidance, we had talked about the amount of maintenance outage catch-up that we had to do at Units 1 and 2 given that during repowering, we haven't been able to take those units off-line to do routine maintenance.

The effect of that was starting to show as we came through Q1 this year and both units had to be off-line sometimes at the same time and coincidentally aligned with periods of very high pricing. And as a result of that, we had almost a $20 million hit in the quarter resulting in those sort of ill-time outages.

So, when you think about repowering and the outages because of maintenance catch-up that needed to be done, those are all non-normal course items that are not consistent with our reliability and operating practices.

We felt it was important to indicate that we are seeing some degradation in the quarter that is unique to the circumstances of repowering, but as those units come online and we see the increased capacity and reliability, we'll start to see more stabilization in our cash flows and quarterly results.

Benjamin Pham
Thanks for the detailed explanation. And maybe just lastly, on your guidance in general last year, I think you were using more forward curve to set your guidance. Is that different this year that you're more using your internal expectations supplemented by the forward curve?

Sandra Haskins
No, we use the forward curve when we're looking at the current year guidance. I think my comment was with respect to hedging activities.

So, when we're looking at hedging, we have an internal view of where prices are in a given period of time. And that is what guides us in terms of the hedge prices we would be looking for over and above risk mitigation.

But the forecast and the guidance for the current year is always based on forwards.

Benjamin Pham
Thank you very much.

Operator
Our next question comes from Mark Jarvi with CIBC.

Mark Jarvi
Maybe you guys can just outline between the January update and now just sort of the cost increases at Genesee, how that played out? And I guess, your conviction or confidence level that there will be further increases to the CapEx at this point?

Avik Dey
Hi, Mark, it's Avik.

Look, I think from a milestone perspective, so bridging from January until now the key milestone is hitting simple cycle on Unit 1 and 2, which in January, we had guided towards completion in Q2 for Unit 1, Q3 for Unit 2. And as Sandra indicated, our ramp-up in first fire commissioning is where we've endured some uncertainty, but we're on plan for simple cycle.

So, our confidence interval in the revised guidance is, we feel good about the guidance because what's remaining is really the combined cycle construction in particular, on the HRSGs on both units that complete combined cycle.

So, where we have construction remaining is with regards to the combined cycle piece of it. But on completion of simple cycle 1 and 2, we'll have effectively retire the older units and commenced capacity on Unit 1 and 2.

In terms of the revised guidance, the increase accommodates for really two things: costs associated with the outage itself to bring these two units on and then lower productivity, which is reflected in what's left on the combined cycle construction.

think what's important is, we're nearing the finish line, we've made it through major construction and we're in the process of having the first two units up and running. We're not out of the woods completely in that we have major construction remaining on combined cycle, but all the equipment is on stage, and it's really about maintaining productivity and the cost increase reflects the increased cost around labour productivity to get to completion on the project.

Mark Jarvi
So if you think about the new range, is there a buffering at the low end of that number now?

Avik Dey
I don't know that I would say buffering at the low end, but it's why we provided the range is to accommodate contingency within that.

So, the closer we get to completion of the project, the less variability is but we still felt given what our track record is here and how costs and schedules have changed over the last few years, we wanted to maintain the range in the guidance. But as we get closer, the variability will decrease.

Mark Jarvi
And then how do you think about funding the incremental CapEx? I assume it can't be supported by internal debt funding because there's no real offsetting cash flow to this, so does this constrain how much you would have had for M&A later this year or organic development? How are you looking put that? And then, I guess, as you go through commissioning, is there any risk on your hedge position that you're caught off-side?

Sandra Haskins
Thanks, Mark. So, a couple of things there. In terms of the funding of it, we do have plans to issue debt, as we've indicated this year as we come through Q2 and so have the opportunity to do funding there.

We are seeing a decrease in the spend on our Ontario projects that are somewhat offsetting to this, and we'll look at permanent financing once we get closer to the end of the year.

As far as incremental M&A activity to the extent that there is an accretive opportunity, we would look at financing at that point in time. Any commitments to a development would have spending further out, so it would be part of the longer-term term financing plan.

As a result of the overruns, we're not looking at doing anything incremental immediately or in the very near term with respect to financing that it will be funded through the credit facilities, and we'll address that in normal course.

Mark Jarvi
And then on the hedge position, is there any risk there? And when you think about what happened in Q1, was there any losses associated with settling hedges that might have been long seeming on your power production?

Sandra Haskins
That is the risk and that risk occurs at any time, as you know that if you have a hedge position and are unable to cover it, then you do have to cover those exposed positions otherwise. So that is a risk, however, we do expect CBEC 3 to be back online, which gives us more ability to backstop those hedges, which is traditionally how we've managed any outages.

We also expect higher reliability as we get off of simple cycle 1 and less volatility in prices that would mitigate the sizing of those losses. But it does continue to be a potential risk.

Mark Jarvi
And then last one for me, just on stopping the work on the carbon capture. Was that just not getting the contract for difference the pricing on carbon? Was it tax credits? Was it all of the above? Is there anything you kind of point to kind of made you guys put pens down and stop any work on that right now?

Avik Dey
Thanks, Mark.

I would say all of the above, as we indicated in the release and the comments. Fundamentally the economics just don't work where we are on the project.

So that can be attributed to capital cost outlook for dispatch, the contracts for differences. But on all fronts, I think we had collaborative and constructive conversations.

I do feel strongly that carbon capture and sequestration works post combustion for a gas-fired power plant, but the math just doesn't add up in terms of economics and our own equity hurdle rates.

So hopefully the technology will improve and we can revisit this at some point when the economics improve. But it was fundamentally just a decision around the economics at this point.

Mark Jarvi
Understood, thanks to you both.

Operator
Our next question comes from John Mould with TD Securities.

John Mould
Maybe just turning first to California. April, which is admittedly a real shoulder season for power markets, there's been a lot of renewable resources online and relatively low gas output.

I appreciate that La Paloma is driven by resource adequacy and it doesn't need volatility, particularly in this time of year. But in that context, I just appreciate your initial impressions on that asset since you acquired it in February and how you see it fitting in as the merit order is evolving there and we're seeing more storage and solar coming online in that market.

Avik Dey
Thanks, John. I think from our resource adequacy perspective, we're actually feeling really good about the outlook for California and we talked about this when we underwrote the asset and announced the acquisition the reliable, dispatchable generation is critical for reliability and having those resource adequacy contracts is what facilitates reliability on the grid, and we're seeing that uplift in outlook favorably on the RA contracts currently really all the way out to ‘27, ‘28.

So we continue to see positive momentum there, notwithstanding the current market environment and what we've seen on gas. The other point I would make on La Paloma is it's a critical asset because it has its own gas supply coming off an alternative system and it's on the one end of a north-south transmission line in California, that's critical to maintaining reliability in the state. So we see the asset well positioned.

It's largely in line with what we underwrote, and the medium-term outlook continues to be favourable from an RA perspective.

John Mould
And maybe just to circle back on the CCS a little bit, I'm just wondering what would cause you, you said at the end of the last question here, hopefully, you can revisit as technology improves and maybe the economics improve.

I'm just trying to get a sense of, does that require sort of like a fundamental step change in the post-combustion capture technology that's out there? Could you see a combination of changes on the contracting side and the merchant exposure evolve such that maybe it makes sense to take another look at it? Or is it really you need to see a technological leap for that plant, that investment to make sense for your company, given the other returns you can earn elsewhere?

Avik Dey
John, I made the point around the technology improving and what it really is, is it's the technology improving, so the costs come down. How do you actually build the kit so that you have higher efficacy and higher capture rates while bringing down the capital cost?

So, when you step back and look at CCS, there's two components to it. From a revenue side, it's what we would have received in terms of a contract for differences, but it's also cost avoidance on carbon tax itself.

So those are the two contributing factors to establishing the numerator on the NPV calculation.

And then on the denominator, it's really a function of volume, i.e., emissions captured and CapEx per ton captured or CapEx per megawatt exposed. And so, yes, at the end of the day, it's the combination of all three. It's volume, cost and CapEx.
And so, I really wouldn't say if any one thing. I think we need all of it to work to be able to underwrite something that meets our equity hurdle rates.

But if I had to pinpoint one thing today, I think what will unlock CCS post combustion for natural gas-fired power plants is the CapEx per unit coming down such that we can work within whatever regulatory framework exists, whether it's the state of Michigan, the province of Alberta and work within whatever federal framework exists, whether it's the CER or working within the IRA.

So, I do feel positive about CCS for medium to long term, we're just early.

John Mould
I appreciate that colour. And maybe just one last one for Sandra, just on the Ontario costs coming down, and maybe just how you're thinking about what the capital structure could look like for those projects.

It looks like we could get Royal Assent on the ITC maybe in the next month. Just wondering how you're thinking about the funding split between project equity debt, I'm not going to say project debt because I know you won't do or you typically don't do project level financing and maybe the ITC for the renewables and storage portion, how are you thinking about the funding split there?

Sandra Haskins
Thanks, John. As you mentioned, we are expecting Royal Assent on ITCs that would be applicable to the batteries at the Ontario projects. When we implemented the DRIP, it was an indication that, that was the funding that we would be applying to the development projects that were in flight including the Ontario projects, and the rest would be coming through cash flow as we see sort of a backward curve to the spending profile for those assets.

So, no other announcement in terms of specific funding. But as I said, as we build out those projects, we have the liquidity on the credit facilities and our ultimate decision on how we term out that financing will be pushed into 2025 at earliest.

John Mould
Thanks for that, those are all my questions.

Operator
Our next question comes from Maurice Choy with RBC Capital Markets.

Maurice Choy
Good morning everyone. I just want to come back to the Repowering project and the cost increase that you've announced there. With three quarters left to go before you complete this project at the end of this year, can you just elaborate as to how much of the $1.55 billion to $1.65 billion is spent?

Avik Dey
Sorry, is spent to date or where we are on the project itself?

Maurice Choy
Spent to date.

Avik Dey
We're just under $1.1 billion spent to date.

Maurice Choy
And the remainder of the $1.1 billion to your new revised cost estimate, how much of that is, I guess, fixed versus what is spent?

Avik Dey
I would say it's mostly variable because as I said in the earlier comments, it's related to labour and productivity. And so, the fixed cost element of it, which was all largely equipment, all the equipment is on site.

So, what's remaining is really construction commissioning and labour on the combined cycle unit and what's remaining on simple cycle 2 and that's not an exact answer because you have components of that like the outage that are there fixed components to it.

But in the construct of an overall project FID, it's time and labour that's really what's remaining.

So, if you were kind of piecing it between capital equipment and what's variable in nature based on your question, I would say it's more variable in nature.

Maurice Choy
And maybe just a quick follow-up. Obviously you've got, let's call it, $400 million to $500 million left to spend here. How would you characterize your contingency for the remaining spend? Recognizing too that this is not the first cost increase for this project and I'm just trying to figure out how you guys approach, particularly for this project, not in general.

Avik Dey
Yes, I think that's why we put the range in place that we did, it is to accommodate that. I don't think I can specify what specific contingency is.

But I would say contingency reflects two things: normal course contingency in a project for the full 100% of the project. And then we've put a range in recognizing where we are today and specific contingency, which is why we've given the range.

I know it's not a precise answer to your question, but I think that's why we have the wider range given where we are and how close we are to completion of the project.

Maurice Choy
And maybe just separately to that, when the cost was increased to $1.35 billion about mid-last year, I remember you mentioned that the levered return was more than 30%.

What is your latest estimate of the levered return for this project right now? Given this cost increase, given the uncertainty on REM, not to mention that the carbon tax trajectory may change if we have a change in federal government next year?

Sandra Haskins
So Maurice, we haven't rerun the returns at this level, but it certainly would exceed our levered equity hurdles as the project was, as you mentioned, very deep in the money last year at 1.35, and certainly that would not have changed with this escalation.

So, if we were to make this investment decision today, we would still be proceeding with this project without hesitation, but I can't give you an exact update to that number.

But it would be certainly highly accretive, it remains a very highly accretive project.

Operator
Our next question comes from Patrick Kenny with NBF.

Patrick Kenny
Just to come back to your U.S. footprint here. And again, I don't want to steal too much thunder from next week, but specifically on the momentum around data center power demand growth, just wondering if you could provide a bit of a preview into how we should be thinking about your positioning, ability to capitalize on this opportunity? Which assets within your portfolio might be best situated for near-term expansion or contract extension? And also, which regional markets you might view as being most attractive in terms of participating in the need for more immediate gas-fired generation?

Avik Dey
Thanks, Patrick. That will be stealing our thunder from our conversation next week. But just a preview, as we think about increasing load demand coming from data centers, so a hyper data center would be a minimum 1,000 megawatts, million square feet of footprint. And the key challenge for data centers is, you cannot rely on

intermittent supply, you need firm supply.

And what most of utility commissions, system operators, load-serving entities are dealing with is reliability concerns because we're hitting that threshold in which reliability is being compromised because we have too much renewables and not enough firm capacity.

And so, as we've been saying from last year, you can't have renewables without having dispatchable generation, which is what we provide on natural gas. When you look at the data center at play, the conversations that all of the hyper data center builders and large technology companies are faced with right now is how do you access firm capacity physically.

So, 65% of PPAs in North America have been historically held by large tech companies, and many of those PPAs are held in places that are not physically procuring the power.

Well, all of those costs are actually being burdened to ratepayers through rate base in those local markets. And so, where we see the opportunity with data centers is really working with off-takers to provide balanced energy solutions, which is what we've been in the business of 15 years doing, which is how do you provide behind the fence generation, how do you provide contracts? How do you provide medium- to long-term solutions for those corporate data centers to get from capacity?

The markets that are interesting, if you look at the U.S., three of the highest growth markets for data center demand are the Northwest, California, and Arizona. So we're positioned in each of those.

In terms of specific assets, I think I'll defer that to the Investor Day, where we'll talk about that in some detail.

Patrick Kenny
I appreciate that overview. Maybe for Sandra, you touched on it, but based on the lower financial performance expected for the year, combined with the incremental capital needs here at Genesee, can you just confirm how you're thinking about your need for potentially boosting liquidity or your desire to improve leverage ratios over the near term? Do you see any need to bring in any additional equity onto the balance sheet or perhaps additional partners over and above in Ontario just to fund your capital budget over the next 12 to 24 months?

Sandra Haskins
Thanks, Pat. So as you know we normally have a lot of different avenues we can approach with respect to financing and certainly partnerships with. We do have a partner at one of the sites that we already have in Ontario where we are doing some incremental projects there. That is an opportunity. Capital recycling remains an opportunity as well as bringing in partners elsewhere.

So, there's a number of different things that we can do but nothing that we feel needs to be done immediately in order to support the balance sheet. So, still remains strong on leveraging credit metric criteria.
So, nothing forthcoming immediately in terms of incremental financing plans beyond what we've already announced.

Patrick Kenny
And then just in light of the potentially higher for longer interest rate environment, any update on the timing for refinancing the MTNs due in September?

Sandra Haskins
Yes, so we do plan to refinance those.

We have hedged the underlying that is deeply in the money, which will bring down the overall effective cost of that debt.

As you may recall we had hedges on our previous refinancings and most of our financing is out to about 2026. So, don't expect any changes with respect to timing as a result of interest rates.

However, we will look for opportune windows where we have a constructive market to go in and do our transactions.

Patrick Kenny
Thanks Sandra, thanks Avik, I'll leave it there.

Operator
And I'm not showing any further questions at this time. I'd like to turn the call back over to Roy for any closing remarks.

Roy Arthur
Thank you. If there are no further questions, with that, we will conclude our conference call. Thank you once again for joining us and your interest in Capital Power.

Today's presentation and webcast will be made available on capitalpower.com.

Have a great day.

Operator
Ladies and gentlemen, this does conclude today's presentation.

You may now disconnect.

And have a wonderful day.