Capital Power
Q2 2024 Results Conference Call
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Operator
Good day. And thank you for standing by. Welcome to the 2024 Second Quarter Capital Power Analyst Conference Call.

(Operator Instructions)

Please be advised that today's conference is being recorded.

I would now like to hand the conference over to your first speaker today, Roy Arthur, Vice President of Investor Relations.

Please go ahead.

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

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

First, our call will feature business highlights that will be presented by Avik Dey, President and CEO.

Then Sandra Haskins, our Senior Vice President of Finance and CFO, will provide a review of the financial performance of the business.

Once we have finished discussing the quarter for Capital Power, Pauline McLean, our Senior Vice President, External Relations and Chief Legal Officer, will provide a brief Alberta Regulatory update.

At that time, Avik will provide some closing remarks.

And we will then welcome questions from the analysts in our interactive Q&A session.

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 on 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 Slide 3.

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.

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 can be found in our 2023 integrated annual report.

Before we begin the presentation, I would like to acknowledge that 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 the Metis Nation of Alberta Region 4.

We acknowledge the diverse Indigenous communities that are in these areas and whose presence continues to enrich the community and our lives as we learn more about the Indigenous history of the lands on 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 second quarter of 2024, we continued to make significant strides across our three strategic areas of focus as we continue our journey of powering change by changing power.

In this quarter, we delivered nine terawatt hours of reliable and affordable power across our strategically positioned fleet of assets, adding to the generation delivered for the quarter are the megawatts from our newly acquired assets that continue to perform well and enhance the diversification of our fleet.

As part of our ongoing commitment to investing in and optimizing our assets to maximize our operational efficiency and life, we have progressed our prescribed asset maintenance schedule. Year to date, we have finished approximately half of our 295 scheduled outage days for 2024 on our fleet, and remain on track to our guided range of $180 million to $200 million of sustaining CapEx.

We are proud of our significant milestone of being 100% off-coal five years ahead of the government mandate, achieving simple cycle commercial operation on Genesee 1 and 2 this quarter.

As we will talk about, our Ontario portfolio continues to generate steady cash flows and is proceeding with respect to our five projects that, upon completion, will add 350 megawatts to our portfolio.

In addition, we entered into a PPA with Duke Energy for the North Carolina solar projects as part of our ongoing effort to derisk the cash flows in our business and create value for our customers.

Lastly, we continue to pursue the creation of end-to-end solutions for our customers as we are actively pursuing data center opportunities in Canada and the U.S. This effort has been more focused on the U.S. until recently, however, for reasons Pauline will discuss later in the call our confidence level is growing for this type of load coming to Alberta.

Regarding Genesee, we are continuing to advance this project and will briefly touch on the significant milestone. In Q2, we achieved simple cycle commercial operations on both Unit 1 and Unit 2, resulting in 411 megawatts of capacity for each for each of Unit 1 and Unit 2. You will have seen these units, Genesee Repower 1 and 2 contributing baseload megawatts to the grid on the AESO website.

We are now advancing toward the combined cycle operation of Unit 1, occurring as early as October, and aiming for Unit 2 shortly thereafter. This will take us to 466 megawatts of total capacity.

Finally, in the new year, we will aim to implement a technical solution allowing us to exceed the current MSSC set by the AESO, taking us to 566 megawatts.

As a reminder, total capacity for these units is close to 666 megawatts, meaning the total capacity for G1 and G2 is about 1,300 megawatts or 512 megawatts higher than the combined capacity of the legacy dual-fuel units.

As we discussed at Investor Day, we see upside and look forward to working with the AESO on a solution to unlock the total capacity of Genesee 1 and 2 for Alberta.

Our Ontario asset base continues to contribute stable contracted revenues in addition to compelling risk-adjusted return potential for our growth projects.

At Goreway, we saw generation of 552 gigawatt hours due to execution of scheduled turnarounds. When combined with our Q1 generation of 799 gigawatt hours, we are on pace for a generation close to what we saw in 2023, which was a record year for generation at this facility. The battery energy storage solutions at York and Goreway will mobilize and commence construction in Q3 of 2024.

We now have greater visibility to the total cost, which is why we are able to reduce our total cost estimate for the two BESS projects and the East Windsor expansion to $600 million from $650 million, as we indicated in Q1.

Lastly, our uprate projects like Goreway and York are proceeding on time and favorable relative to budget.

I would like to provide an update on our U.S. business, which has continued to grow and demonstrate the resilience of our business model.

As a result of our recent M&A, this business currently comprises 10 generation facilities and just over 50% of our total capacity. This is up from approximately 39% in Q2 of 2023.

From an adjusted EBITDA standpoint, we have seen the U.S. contribution rise from 26% in Q2 of 2023 to 43% in Q2 2024.

While our strong contractual underpinning drives cash flow stability near term, longer term, the strong fundamentals continue to support the thesis of natural gas-fired generation playing an essential role in reliable and affordable grids for North America. The specific trends we continue to see are: one, strong demand growth that we expect to continue long term, such as reshoring, EV mandate data centers; two, continued retirements of coal-fired facilities; and three, further advancement of renewable generation capacity.

Now I would like to zoom in a bit and provide some additional data points that we believe reaffirm our long-term strategy and outlook for natural gas-fired generation.

Our U.S. thermal portfolio now encompasses 4.2 gigawatts of capacity, resulting in nearly four terawatt hours of generation in Q2 2024.

For this quarter, I would like to highlight the performance of Midland Cogeneration Venture, which we acquired in 2022. This asset has contributed seven full quarters in our portfolio and have seen steadily rising utilization during that time.

In Q2 2024, MCV achieved 1.45 terawatt hour of generation, implying a capacity factor of just over 80%, making it a record in this asset's 34-year history.

This is a tangible example of the strong fundamentals we have thought out in our M&A strategy coming to fruition.

Looking more broadly at our U.S. thermal portfolio, we have six facilities with approximately 5,000 acres of surplus land.

We believe the strong fundamentals we continue to see strengthen the case for recontracting, optimization, and expansion of existing facilities in the near- to medium-term. Long-term, our surplus land can be used for other balanced energy solutions up to and including greenfield growth.

We look forward to providing further updates as we advance commercial dialogue on these fronts. And with that, I will hand it over to Sandra to provide a financial update for the quarter.

Sandra Haskins
Thank you, Avik.

I will start by touching on the financial highlights for the second quarter of 2024.

Overall, second quarter financial results were modestly lower year-over-year due to lower generation and captured prices from the Alberta commercial segment.

However, the Q2 results benefited from increased U.S. facility contributions with Q2 2024 being the first full quarter where we realized the favorable impacts from the acquisition of Harquahala and La Paloma.

The quarter also realized lower emissions costs driven by lower emission intensity at our Genesee facility, which is now fully off-coal.

For the quarter, adjusted EBITDA of $323 million was down approximately $4 million period-over-period. AFFO of $178 million in the quarter was up $27 million from a year ago, primarily due to lower income tax expense, higher contributions from our joint venture investments in Harquahala and partially offset by higher finance expense.

For the first half of 2024, adjusted EBITDA was $126 million lower year-over-year due to the same factors impacting Q2 results. AFFO was $41 million lower than the corresponding period in 2023, driven by lower adjusted EBITDA and finance expense, higher sustaining CapEx from our recent acquisitions and larger outage scope, and finally, higher preferred share dividends.

This was partially offset by decreased income tax expenses and higher contributions from our joint venture investment in Harquahala.

We have provided a simplified breakdown of our quarterly adjusted EBITDA by region. The period-over-period 78% increase in adjusted EBITDA from the U.S. is largely driven by the acquisitions of Frederickson 1 at the end of 2023 and La Paloma and Harquahala in the first quarter of 2024. This increase in the U.S. adjusted EBITDA combined with the 27% lower contribution from Alberta reduced the relative contribution from Canada overall, as compared with last year.

As discussed, the lower contribution from Alberta was driven by lower prices and lower generation from our legacy dual-fuel Genesee units, which we have since retired. Q2 2024 was consistent to Q2 2023 for the rest of Canada, demonstrating the stability of the contribution from these assets. Essentially, we are seeing the benefits to our diversification efforts through the reduced adjusted EBITDA volatility from our portfolio outside of Alberta commercial, which is in transition year as we advance the Genesee Repower project towards combined cycle operations. To put those results into perspective, I would like to touch on our dividend payout track record.

Since 2013, we have delivered annual dividend increases with a compound average growth rate of 7%. This year marks the 11th consecutive annual increase.

Our ability to deliver sustainable and growing dividends to our shareholders while maintaining a low-risk capitalization and investing in attractive growth opportunities remains a core part of our disciplined capital allocation strategy.

As a reminder, at Investor Day in May this year, management announced a targeted dividend growth guidance of 2% to 4% beyond 2025 with our increased focus on investing in our growth opportunities over yield.

Now I would like to highlight the success realized during our most recent financing.

Capital Power was the first issuer in Canada to adopt a new 30-year hybrid structure with no coupon step-ups or automatic conversion to preferred shares, successfully closing a $450 million hybrid bond in June, which matures on June 5, 2054.

In addition to being successful in placing a larger-sized deal than anticipated, this transaction was more than 2x oversubscribed.

In this case, the economic savings of replacing the 150 million Series 11 preferred shares are approximately $3.4 million per year on an after-tax basis for the initial 10 years compared to the reset rates of the preferred shares.

Prior to the bond offering, we entered interest rate swap hedges on the underlying with a positive mark-to-market settlement of the hedges, the effective interest rate of the bond is 7.7%, which is 50 basis points below the coupon rate of 8.125%.

In short, hybrid bonds continue to provide cost-effective financing relative to preferred shares, making them an integral part of our capital structure.

I'll conclude my remarks by reviewing our 6-month performance relative to our 2024 guidance and provide an update on where we expect to land for the year.

On average, facility availability was 92% in the first half of the year, just below our target of 93%.

Sustaining CapEx was $81 million in the first six months and is on track to meet the 2024 target of $180 million to $200 million.

Our guidance presentation in January 2024 provided financial guidance for 2024 AFFO in the range of $770 million to $870 million and 2024 adjusted EBITDA in the range of $1,405 million to $1,505 million. Based on the company's results for the first half of 2024 and forecast for the balance of the year, we expect 2024 full-year AFFO at the midpoint of the original guidance range.

Regarding adjusted EBITDA, we are revising the range to be $1,310 million to $1,410 million. The updated adjusted EBITDA guidance range is driven most notably by the impact of lower Alberta power prices in addition to the impact of the outages at Genesee during the first half of the year.

Overall, we remain pleased with the financial performance of the business during a pivotal year where we have achieved some significant milestones that have positioned it from a financial perspective as larger, lower risk, more diverse, and more competitive.

Now that Avik and I have concluded the quarterly update on Capital Power, I will now hand it over to Pauline McLean, our SVP, External Relations and Chief Legal Officer, to provide an Alberta regulatory update.

Pauline McLean
Thank you, Sandra. And good morning, everyone.

As many are well aware, Alberta's Grid has been transforming significantly with the phase out of coal, increased penetration of renewables, decarbonization, electrification and the potential for load expansion.

In response to this, Alberta's government has embarked on an effort to modernize Alberta's electricity grid to ensure that it is affordable, reliable and sustainable over the long term.

On July 11, 2024, the Minister of Affordability and Utilities, the Honorable Nathan Neudorf, announced major policy decisions concerning the future direction of Alberta's Restructured Energy Market.

If you recall this was a design originally announced by the AESO on March 11 earlier this year.

With the more recent July announcement, the government has provided clarity on key market and transmission policy issues that will evolve the market, support investment, and most importantly, deliver on customer needs for both reliable and affordable electricity.

In the announcement, the government confirms that Alberta's competitive energy-only market, where price signals are based on market participants, competitive and strategic offers, rather than administrative actions, will be preserved.

In addition, the government committed to moving to a day-ahead market, which will provide enhanced price and operational certainty for generators, as well as the broader system. These decisions mark a critical evolution in the market design that was originally presented by the AESO in March, and Capital Power views these changes positively with respect to maintaining confidence and stability in the market.

Another aspect of the announcement was that there will be further consideration of the market power mitigation measures that went into effect in Alberta on July 1, 2024, in order to ensure that customer affordability is maintained.

On transmission policy, there were two key changes announced. The first was the move away from a congestion-free planning of the grid to an optimal transmission planning approach. The second announcement was that the future cost of new bulk transmission would be allocated on a cost-causation basis. Both of these decisions provide clarity on what has been a long-running set of discussions on these topics over the past four years.

The AESO will be consulting on the technical implementation of these policy changes, and we will be fully participating in the stakeholder engagement process this fall.

It's expected that detailed designs will be set out by the end of this year, if not early 2025.

Now when we look at what these key large policy decisions mean for the province, we see an evolution in modernization of Alberta's market that maintains the successful nature of Alberta's openly competitive market, namely one that minimizes administrative complexity and regulatory risk, while also introducing operational changes to the market that are featured in many other markets across North America. The AESO's initial market design materials have indicated that they are considering an increase to the price cap in the neighbourhood of $2,000 to $3,000 per megawatt hour.

If this change is ultimately implemented, this would bring Alberta into line with neighboring jurisdictions on pricing in the market, which would support trade when the market tightens and encourage generators to be available when they are needed most.

While these design elements may be new to Alberta, they do exist in numerous other markets across North America. And Capital Power is very familiar operating in these markets where the features exist and therefore, we view their implementation in Alberta positively.

For Capital Power, maintaining the essence of the energy-only market by preserving the use of strategic offers, supports our trading activities in Alberta, where we have a long-standing deep expertise. This further supports investor certainty as it will keep the pricing framework closest in line with the existing market. The pace of the planned engagement and plans for implementation in a compressed timeline also support investment in Alberta.

While it is early days on seeing incremental load like data centers located in the province, driving to a detailed design on an expedited timeline to get to clarity will deliver on certainty for both ourselves and loads.

Overall, the changes, particularly on the price cap and day ahead market are favorable to a portfolio like ours that is comprised of numerous dispatchable assets and is not wholly made up of renewables.

We plan on continuing to work with the AESO and government to progress implementation of the many policy decisions, and we are keen and excited to see clarity on the horizon for the Alberta market. And now I will turn things back over to Avik.

Avik Dey

Thank you, Pauline.

I would like to conclude this call by reiterating that we remain steadfast in our focus to deliver reliable and affordable power today while building clean power systems for tomorrow and creating real net-zero power solutions for our customers.

We look forward to continuing to provide updates on our strategic areas of focus as we move towards the end of a transition year. With that, I'll now turn the call back over to Roy.

Roy Arthur
Thanks, Avik.

Operator, we are now ready to take questions.

Operator
(Operator Instructions)
Our first question comes from the line of Patrick Kenny of NBF.

Patrick Kenny
Avik, you touched on the undeveloped land position that you have in the U.S. Could you just expand on how you're thinking about crystallizing additional value of your existing footprint? And perhaps provide an update on what sort of discussions you might be having with various data customers for, say, co-location opportunities over the near term?

Avik Dey
Thanks for the question, Pat.

As we mentioned in the call we're excited about the opportunity around data centers. In terms of monetizing that opportunity on behalf of our shareholders, what I would say is that the opportunity is multifaceted. And the opportunity in front of us as a generator who's focused on natural gas in the last 15 years is one where we can work with and collaborate with load-serving entities, ISOs and off-takers, be it data centers directly or hyperscalers.

And so, for us, the opportunity is one, to upgrade at existing facilities to accommodate new load, one. Two, evaluate expansion opportunities at existing sites to accommodate additional load. And then three, the one you referred to, which is potentially co-locating for additional load that you would bring behind the fence.

So, we see those opportunities across the portfolio. And as we noted in the call we're now seeing those opportunities on both sides of the border, but they're ones that we have to collaborate and work with ISOs, load-serving entities and the offtakers.

So, to be specific, we do see those opportunities as we've mentioned in previous calls, we have in aggregate north of 50,000 developable acres inside the fence of our existing fleet. And we see multiple opportunities across the U.S. for that opportunity.

We have not been specific about existing sites on either side of the border. But I would say, regionally, there's a lot of activity in data centers generally in Arizona, and we're seeing increasing interest in Michigan as well.

Patrick Kenny
Okay. Great. And maybe shifting to Alberta, I guess, based on the recent transmission policy update, any comments on which of your assets here in the province might be well positioned to capitalize on opportunities to attract new load to the province.

Avik Dey
Well, I would just point towards our crown jewel asset, which is Genesee. So, as we complete repowering, we will have the most efficient gas plant post

repowering and that asset is a large asset as we described in the call we've got a significant footprint there. And in addition, we've got significant acreage there. So there's 30,000 acres in and around Genesee that we control.

But the opportunity, more importantly, isn't about a single site. It's about presenting Alberta as a viable jurisdiction for data centers and presenting it as an attractive market to the hyperscalers for building out long-term capacity.

So there will be multiple sites in Alberta that are attractive, but obviously we feel very strongly about Genesee being a cornerstone asset for us, but also for the province as we present this opportunity globally.

Patrick Kenny
Okay. And I appreciate the update on the regulatory front.

But maybe just at a high level on the Alberta REM design process, sticking with strategic bidding on a day-ahead basis, new offer and price caps coming, potentially looking at new inter-ties, maybe you could comment as well on which of your assets might be best positioned to perform within this new market design once implemented? And perhaps what other concerns you might have with this proposed market framework at the asset level?

Avik Dey
Yes, so maybe I'll start, and then I invite Pauline McLean to offer her comments as well.

But I think most importantly, as Pauline mentioned in her comments, we are preserving the energy-only market and the substance of that market focused on strategic bidding. And that element of the market design is being kept whole. I think with the introduction of the day-ahead market, premise, I think what we've seen in other markets we're in is what that ultimately does is affords a premium to dispatchable, reliable generation.

And what it does is facilitate the balance between intermittent and reliable dispatch. And so, the government in their decision was really looking to find that balance between encouraging decarbonization in the grid, but maintaining reliability.

So, what that naturally biases us towards is large, efficient generation providing critical baseload power. And so for us, that's obviously Genesee given its size and scale in the province.

So, at a high level, that's what we're comfortable with and confident in.

I think in terms of the concerns that we have, it's really just how we put through all of the work through all of the details over the course of the next year to implement the system. There will be some growing pains as we implement market structure design changes, there always is. But I think we've got a strong market here in Alberta.

We are currently oversupplied and medium- to long-term, we see strong growth attributes in this market, in particular, if we in Alberta, can catalyze on the data center opportunity.

So maybe, Pauline, if you have anything you'd like to add?

Pauline McLean
Thanks, Avik.

I think that was a very comprehensive response. The only maybe additional colour I would add is that first of all, I think the fundamentals of the energy-only market will continue. And so all of what's been proposed, we consider to be sort of tweaks around the edges, but it is important again that the fundamentals of the energy-only market are going to be maintained. And I think because of the guardrails have been set, that will very much focus the stakeholder consultation and speed up the process.

And so, as I mentioned in my remarks earlier, when you think about the initial timeframe that the government was looking at in March, they were predicting a new market design by the 2027 period. And at this point, we're driving to probably mid-2025, if not early 2026 by the time, all the implementation details are worked through.

So, from our perspective, very positive because us as well as others will have clarity moving forward on all of those design details.

But certainly, from a high level, we're comfortable with this direction and I think this provides a lot of certainty to others in the market as well.

Operator
Our next question comes from the line of Benjamin Pham of BMO.

Benjamin Pham
On your solar projects you announced, could you share that actually where the power price ended up at or any sort of guidance on EBITDA contributions?

Sandra Haskins
Thanks, Ben. Yes, we haven't given EBITDA contribution guidance on those, just given that the economics are tied up in some of the ITCs that are part of that project. But from a return perspective, it would hit our return hurdles for an equity project.

So, we will look to provide more guidance maybe in the future to help you from your consideration from a modeling perspective, but haven't given guidance specifically to EBITDA, as I said, that's only part of the economics of those projects.

Benjamin Pham
Okay, got it. And maybe going back to some of the comments you had on data centers, can you comment high level when you're speaking with these potential customers, whether it's Michigan, Arizona, or even Alberta, what are they most looking for at this point in time? And maybe just kind of also just frame Alberta too, in terms of some of the pros and cons of that region?

Avik Dey
Sure. Happy to address that, Ben. When we're having the conversations currently, the focus is on one near-term reliable generation that's utility-scale. Two, near-term reliable generation at utility scale that is scalable in the short to medium term, meaning that there's critical access to transmission and distribution and that there's line of sight to scaling that capacity. And then I would say third, is just the general market requirements for large-scale data centers.

So proximity to fibre, proximity to major population centers, access to reliable airports and then the intrinsic or intangibles are ones that are affordable electricity and markets that actually have the right geographic footprint, right temporal climate and right dynamic with respect to climate events or weather events or lack thereof. So it's a multifaceted approach.

I think as we were entering into this late last year, the focus was very much on proximity to existing infrastructure and trying to leverage existing footprint of hyperscalers to scale out their positions.

But, I think as this is playing out, the requirement to get a large load and scalable load in short term is a key priority. And then I think lastly, each hyperscaler is emphasizing continued focus on providing clean electricity over time.

So that's where natural gas is disadvantaged relative to hydro or nuclear in particular, but is advantaged in terms of ability to scale quickly. And so, finding solutions where we can provide a decarbonization pathway over time, whether it's on existing generation or finding solutions to support them, those are the conversations we're having currently.

And with regard to the second question on Alberta. What I would say is when we talked about the generative AI data center load for hyperscalers, it's important to note that as these language learning models are being built up, those are being built up by the hyperscalers on their own balance sheet. And so that first wave of scaling up for these hyperscalers is to build up that capacity so that they can go sell that capacity to commercial users and consumers. And so there is a discrete focus on building out that capacity in the U.S.

Now Alberta, if you were to take an objective lens and say, where could you build out new generation capacity, Alberta has existing transmission distribution capacity.

Alberta has an energy-only market where you can go behind the fence. Alberta has attractive long-term access to natural gas as a feedstock and affordable electricity. And then the climate is extremely well positioned to be a data center load center of excellence given the relative cold and the less energy that's required to support it.

So, what it is incumbent upon us as an industry is to go sell Alberta to those hyperscalers to bring that capacity north of the border.

Because the focus is pretty heavily on building that capacity out in the U.S. today. But if you remove the 49th parallel from the equation, Alberta would be exceptionally well positioned.

So that's where our effort is focused on, going to those end users and say, come to Alberta because we believe it is a fantastic jurisdiction to build out capacity.

Benjamin Pham
So it sounds like Avik, Alberta is similar or even better characteristics to house data centers than some other regions, but it sounds like it's more a lack of understanding or marketability?

Avik Dey
Yes, I think that's a fair characterization, Ben. And it's why we don't want to overstate how imminent it is, but we don't want to understate the potential of it. So it's really upon us to go market the aggregate opportunity and why this is the place we should build out this capacity.

Operator
Our next question comes from the line of Maurice Choy of RBC Capital Markets.

Maurice Choy
I want to speak about the Alberta fundamentals here. Forward prices hasn't really moved and your power hedges remain priced around the same as your last disclosure.

However, I noticed that the gas hedges for the next three years are priced about $1 per gigajoule higher than your last disclosure, although this could very well be rounding.

But given where you are on your gas hedges, is your expectation that power prices will rise from here in tandem? Or will spark spreads adjust accordingly?

Sandra Haskins
Thanks, Maurice. Yes.

So our practice on hedging natural gas is to look at locking in the margin when we do some of the hedging on the power side or lock in C&I customers. So, as market prices went up, we would have been pricing those contracts or those hedges based on where we wanted to be from a spark spread perspective and locking that in. And that's why you'll see that has gone up.

And to your point, rounding does play a factor in it. So when you're looking at the dollar given how we report it, probably overstates it somewhat, but it's the activity there is really locking in the margin at the time as opposed to playing a speculative view on gas, going forward.

Maurice Choy
And maybe as a quick follow-up to that, obviously power prices have progressively come down for the outer years. Can you kind of just refresh us on your view as to how you see the trend for 2025 power prices moving forward? Obviously we just completed the first month under the new mitigation measures, what impact they may have on your outlook?

Sandra Haskins
Yes, exactly. I think in the short term, you've seen sort of a reaction from the market based on the market reform on views of what could be announced there, but also just on where prices have been settling this year.

So we've seen lower prices, less volatility in the near term as well as some unseasonal weather just at the beginning of the year. And so I think that as you'll continue to see volatility. So our view really hasn't changed.

You are seeing that supply coming to the market that does drive prices down lower, but you will still continue to see periods of volatility, which are very hard to sort of factor in or to forecast when those periods might be.

But as we've said before, it will be driven by weather, driven by performance of assets in the market that will cause those periods of price spiking.

So, I think that what you're seeing in $50 forward is probably on the low-end of what you would expect for 2025, but that's relatively unchanged. And as you know it's a market that can change quite quickly, if you start to see movement in prices in the immediate settle.

Maurice Choy
Understood. And maybe just to finish up, Avik, I know you mentioned that you will provide further update on greenfield opportunities as they advance in terms of commercial dialogue. What tends to be the gatekeeping factor for these counterparties to move ahead?

Obviously you've spoken about a lot of positives on the Alberta side, is policy certainty one of it, is price one of it? What stopped them from signing on right now?

Avik Dey
So I think you characterized Alberta correctly.

I think in the U.S., the challenge, it's very interesting, actually.

If we were having this conversation a year ago, prior to the growth around data centers being the hot topic, we would have said the single biggest issue is interconnects, and working through that interconnect queue with ISOs and load-serving entities. And so now when you roll forward to the data center opportunity, that continues to be the #1 bottleneck is identifying where you can actually add capacity and have access to transmission and distribution and meet the needs of the load market.

So, what the single biggest barrier today, in addition to the commercial terms, because that's table stakes to be able to walk through the door, but that's only step 1.

Once you have an arrangement with an offtaker, then you have to go hand-in-hand to the other counterparties, the load-serving entities, and the ISOs and identify how to bring that capacity into the market.

Because in many cases, you're looking to find ways to do that outside of the existing queue. And that's the pressure that you're seeing in the U.S. market and the conversations around should we be bringing on this much load into specific electricity markets, it's around what's the burden on consumer for having this new capacity come on and the transmission and distribution costs being borne by that consumer.

So it's one of the key reasons we wanted to provide the Alberta market structure update as well because what we've seen historically is these energy-only markets are having to face some of these challenges first, and are most well positioned to address those changes because you can do it from a single point rather than having to have a multiparty negotiation where you've got competing interest between load-serving entities, regulator and market participants.

Here we have, in places like Texas and Alberta, you've got another level of flexibility because you can have a direct engagement with all the parties to get to an outcome.

So hopefully, that provides a little bit of clarity to your question. It's not a straightforward answer, but I think that's where we see the opportunity is to really roll up our sleeves and be the collaborator of choice to make some of these projects happen.

Maurice Choy
Just as a quick follow-up, does that mean that we have to wait until mid-2025 or early-2026, as Pauline alluded to on the timing of the new market design before we can see something meaningfully signed?

Avik Dey
I don't think so.

I think, in particular, because going into the market structure reform in Alberta, we already had the market conditions to be able to accommodate new load. I think what happened on March 11 is we introduced significant ambiguity around how the market would look. And now that that's been clarified, I think we've got a clear roadmap to be able to introduce that new load.

So I don't, we're not waiting for those rules to get ratified and codified to be able to act. I don't think that's a critical path item at this point.

Operator
Our next question comes from the line of Mark Jarvi with CIBC.

Mark Jarvi
So Avik, maybe coming back to the comments around having to build awareness and get out in the market to explain the opportunity how Alberta can serve the data centers. Where are those discussions now? How do you present that opportunity? Is that coordinated

with government? Is there anything you need to see from government to step up to help entice data centers to show up in Alberta?

Avik Dey
Thanks, Mark.

I'll have to say, the Alberta government has been unequivocal in their support to bring this industry to Alberta. So, whether it's from the Premier herself, the Ministry of Affordability and Utilities, the Ministry of Technology, the Ministry of Energy, the support is there. The willingness to collaborate is there, the willingness to engage with counterparties to show the provinces interest in bringing this load to the province, it's there in spades.

So, where we're focusing our attention on is demonstrating how Alberta relative to other markets is positioned to bring that load in on an expedited basis.

So, if you want scalable generation that you can scale over the next two to five years, then Alberta is the place to do it, and you can do it reliably, you can do it affordably. And there's a pathway to doing it in a decarbonized fashion, given notwithstanding our own canceling the Genesee CCS project, but the CCS infrastructure in Alberta is well down the path of commercializing.

So the medium to long-term potential is there. And I'll note also, Amazon Web Services has a major data center, a super center, just outside of Calgary. So, Alberta is a well-known jurisdiction and established jurisdiction for data centers. But when you go down the path of looking at hyperscalers, it's a little bit of a different trade given how early we are in the build-out of that capacity on behalf of the hyperscalers.

So, we do have to market it, and we have to market it as a jurisdiction. It's not so much about the plant or the site, it's about why Alberta is well-positioned to capitalize on the opportunity.

Mark Jarvi
Understood.

Have you been able to get in front of the hyperscalers to present your case yet?

Avik Dey
Yes.

Mark Jarvi
Maybe just turning to the U.S. market, we've shown an ability to execute on M&A for the last several years. Just curious what the market looks like now when you think about where the last couple of deals were done sub-7x EBITDA. Any view in terms of where you see the opportunity to acquire more assets in the U.S.? Is that still a priority and any sort of indications of where you think pricing and transactions could be completed today relative to the last couple of years?

Avik Dey
Yes.

I think just generally, we continue to see opportunities in the M&A market.

I think what we benefit from, Mark, is there's not many strategic buyers of natural gas-fired power generation.

We've historically competed against private equity-backed entities and they are continuing to be formidable components in acquiring assets and provide the majority of liquidity in asset markets for those assets.

But we haven't seen large public companies or public IPP competitors competing in that space yet. So, we continue to see compelling opportunities in the space. I think our approach to

M&A hasn't changed, we've been very consistent in how we screen for assets.

We look for those assets that are reliant on thermal, natural gas for baseload. We look at market structures that allow for commercial and industrial customer offtake and we look to those markets that have really leaned in on renewables, creating that market opportunity where we can play the reliability gap. All of those thematics are amplified when you now overlay that with electricity demand and growth.

So we continue to see those opportunities. We continue to see compelling value and the value is coming mostly because we don't see a much broader universal buyers for these assets because you need the operating skills that we have to go extract that value.

It's hard to do that passively through passive interest in these assets. You need to have the operators, you need to have the maintenance and sustaining CapEx teams in place to be able to execute, you have to be able to trade around existing generation, and you've got to be able to commercialize and work with, we keep coming back to the same thematic around the importance of working with the ISO regulators and load-serving entities. Well, that requires boots on the ground. That requires core competency and expertise.

We are the only public company in North America who's been actively acquiring natural gas-fired facilities across North America on both sides of the border and optimizing them, operating them.

So we have that credibility in front of ISOs to have those conversations.

Mark Jarvi

A couple of follow-up questions. Just given your track record, are you getting more inbounds from firms with capital that want to get in this space but need an operator, as opposed to you looking for financial support? And then second, given success over the years with recontracting and potential tightness in the market in next couple of years, are you willing to take a little bit more of an open position or shorter contract terms that gives you that there'll be an opportunity to lock in contracts over the next three, four years?

Avik Dey

Yes. Taking the last question first.

I think we've been and remain committed to maintaining our investment-grade status. And so, maintaining our minimum level of contractedness to meet that threshold has been a key priority. And I think what's been, what we've observed that's been interesting in the market on the contracted side is, so I think we've always struck that right balance.

But I would say the governor has been maintaining our investment-grade balance sheet.

What's interesting on the recontracting piece is that historically, you would start those conversations two to three years before the expiration of the contract for recontracting. And what we're seeing now is we're being approached for recontracting much further out.

So, I think our ability to commercialize those market opportunities, like we do in Alberta on a regular basis, is our ability to contract rather than necessarily be completely open.

But, on being open, that's where you can go contract and bring in load to medium, long-term offtakers like data centers. So, there's a balancing act there that we're very careful to maintain.

But because we've got the footprint to be able to go uprate and expand, those conversations become a little bit easier. And then remind me, what was the first part of your question?

Mark Jarvi
Just whether or not you're getting inbounds from partners to look at deals versus you may be looking for financial partners to help you size a deal correctly.

Avik Dey
I think in fairness, Mark, we were getting those inbounds previously. We've got a good track record of partnering with others, whether it's Manulife or BlackRock or bringing AIMCo in the private placement. So that's consistently been an inbound for the company and continues to do so.

But I wouldn't say it's any more or less today than it was a year ago. I think those parties that want to partner with us are keen to partner with us for that operating capability. So we continue to see a deep inventory of potential partners.

Operator
Our next question comes from the line of John Mould of TD Cowen.

John Mould
Maybe just continuing on the M&A theme. At your Investor Day, you highlighted PJM and ERCOT as potentially new markets you were looking at.

I'm just wondering how your evaluation of those markets is proceeding, just more on the bigger picture level, just in terms of your comfort with maybe investing in one of those? And how your opportunity set, like how the opportunities that you're seeing in the market more broadly is weighted? Is it weighted more to some of your existing footprint regionally or are you seeing kind of interesting opportunities in those markets? And I'm asking a little bit in the context of the big jump in PJM capacity option prices that we saw yesterday from previous years.

Avik Dey
Yes. Thanks for the question, John.

On PJM, for example, one of the reasons we highlighted that as a market we were interested in is we saw that growing dynamic of increasing need for reliability to support growing electricity demand.

I mean we certainly didn't see what the print would be yesterday, but we saw the trend medium term going in that direction. So, I mean we're encouraged by it, we continue to like PJM.

In terms of M&A activity, we've tried to be very focused in trying to screen assets in places we want to grow.

I think there's many assets that are for sale. There's many owners that are bringing their assets to the market given the shift in market sentiment towards natural gas-fired generation.

But we continue to see opportunities in WECC, in MISO and in PJM. And, obviously ERCOT is always a very liquid market, so there's always things trading there.

But we see opportunities across all of those markets currently.

I think PJM will get more attention now given the recent print, but we continue to still believe in the potential there medium to long term, and we do think there will be opportunities that present themselves to us in that market and others.

John Mould
Okay. Great. And maybe just one more on your renewables kind of ambitions, you announced just those PPAs.

Today I'm just wondering what kind of cadence you're hoping you'll be able to advance that first solar panel commitment that you've got in place and sort of where like maybe beyond North Carolina, which is where you've got some identified development sites, kind of where you're seeing the best opportunities to potentially allocate those panels as we get into, I think it's a 2026 to 2028 sort of delivery timeframe, and how you're hoping that will advance?

Avik Dey
Yes. And what I would say is when we entered into the first solar agreement to acquire the gigawatt of panels for delivery in '26, '27, '28 we felt like we had sufficient pipeline.

We've got over two gig of pipeline of development inventory in the U.S. that we would be able to fulfill that with a reasonable confidence, level of confidence in '26, '27, '28, and that's largely played out.

So I think we've got, our opportunity set is across the U.S. We've historically had an opportunistic approach to building out our capacity.

But I would say when we took that step on underwriting that gigawatt of panels, it was really against that existing inventory that was in place at the time. And we're, I would say, today, largely on track against fulfilling it against that inventory.

So we really haven't had a shift in our strategy on U.S. solar with regard to placing those panels, so I wouldn't see an acceleration or a delay. I think we're on track to fulfill our existing plan on renewables, on solar in the U.S.

Operator
(Operator Instructions)
Our next question comes from the line of Robert Hope of Scotiabank.

Robert Hope
Just one question for me. Just with the addition of, we'll call it, the U.S. solar projects, does tighten up the capital plan a little bit here, largely in '25 and '26.

But can you give an update on how you're thinking about funding the rest of your growth as well as it does look like you're tight on an FFO to debt basis on 2024?

Sandra Haskins
Yes. Thanks, Robert.

As far as being tight on FFO to debt, yes, when you look at where we're projecting to be this year, it is right on top of the thresholds for S&P.

As you know last year, we were trending because of higher power prices and higher results in Alberta to be well above our thresholds and always knew that, that was a temporary lift in those metrics to be trending to be a notch above our current rating. And we'd always expected that for this year, we would come back down to be more in line and where we're seeing it coming in at this point.

And that's driven by, as you said, the amount of projects that we have in flight right now that are a drag on the balance sheet and also with it being a transition year at Genesee with repowering seeing lower cash flow in the year and lower generation. And as a result of that, we see this year as being sort of the tight point or the tight year on our leverage.

And going into next year, we'll have a full year of impact from Harquahala and La Paloma, which, for this year, we basically missed the early part of the year with those assets. And we'll also have Genesee back with larger capacity and available to us for the full year.

So starting to see the projects that are coming online start to make contributions over time that will alleviate the strain that we're seeing coming through this year.

And from an investment grade perspective, we do have continual contact with the rating agencies as to where we are and what our forecasts are and aren't in a position where we're looking at there being any kind of a problem there with this year being sort of a bottoming out, if you will, of our trend on our credit metrics.

As far as funding, we do have a refinancing coming up in September, which we could look to upsize as part of that funding. That would be the only thing we have coming up this year. Next year, there is nothing maturing for us that would give us the ability to raise more capital next year.

So we have not signaled anything there, but see cash flow, the use of our credit facilities, and then we'll look at that point in time how we best sort of term out any draw that we have on our credit facilities to back the incremental spending that we have on those growth projects.

So expect to come with a more detailed financing plan for 2025 and the remaining spend on those projects as we get into our 2025 guidance period.

Operator
Thank you. I'm showing no further questions at this time.

I would now like to turn it back to Roy Arthur for closing remarks.

Roy Arthur
If there are no more questions, we will conclude our conference call. Thanks again for joining us and for your continued interest in Capital Power. Today's presentation and webcast will be made available on capitalpower.com.

And we hope you have a great day. Thank you.

Operator
Thank you for your participation in today's conference. This does conclude the program.

You may now disconnect.