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Corporate Speakers:

- Stephanie Paris; TransAlta Corp; Vice President of Investor Relations and Corporate Strategy
- John Kousinioris; TransAlta Corp; President and Chief Executive Officer
- Joel Hunter; TransAlta Corp; Executive Vice President, Finance and Chief Financial Officer
- Blain Van Melle; TransAlta Corp; Executive Vice President, Commercial and Customer Relations

Participants:

- Robert Hope; Scotiabank; Analyst
- Mark Jarvi; CIBC; Analyst
- Maurice Choy; RBC Capital Markets; Analyst
- Patrick Kenny; National Bank; Analyst
- John Mould; TD Cowen; Analyst
- Benjamin Pham; BMO; Analyst

PRESENTATION

Operator^ Good morning. (Operator Instructions) At this time I would like to welcome everyone to TransAlta Corporation Fourth Quarter and Full Year 2024 Results Conference Call. (Operator Instructions) Ms. Paris, you may begin your conference.

Stephanie Paris^ Thank you, [Towanda]. Good morning, everyone. My name is Stephanie Paris. And I am the Vice President of Investor Relations and Corporate Strategy of TransAlta. Welcome to TransAlta's fourth quarter and full year 2024 conference call.

With me today are John Kousinioris, President and Chief Executive Officer; Joel Hunter, EVP, Finance and Chief Financial Officer; and Blain van Melle, EVP, Commercial and Customer Relations.

Today's call is being webcast, and I invite those listening on the phone lines to view the supporting slides that are posted on our website. A replay of the call will be available later today, and the script will be posted to our website shortly thereafter.

All the information provided during this conference call is subject to the forward-looking statement qualifications set out here on Slide 2, detailed further in our MD&A and incorporated for the purposes of today's call.

All amounts referenced are in Canadian dollars unless otherwise noted. The non-IFRS terminology used including adjusted EBITDA and free cash flow are reconciled in the MD&A for your reference.

On today's call John and Joel will provide an overview of TransAlta's quarterly and annual results. After these remarks, we will open the call for questions. With that, let me turn the call over to John.

John Kousinioris^ Thank you, Stephanie. Good morning, everyone. And thank you for joining our fourth quarter and full year conference call for 2024.

As part of our commitment towards reconciliation, I want to begin by acknowledging that our company operates on the traditional territories of indigenous peoples across Canada, Australia and the United States.

We recognize the rich and diverse histories, cultures and contributions of the First Nations, Inuit, Metis, Aboriginal and Native American communities. It is with gratitude and respect that we thank the peoples who have lived on these lands for generations for reminding us of the ongoing histories that preceded us.

TransAlta delivered strong financial and operational performance in 2024 at the upper range of our guidance, reflecting the value of our diversified portfolio and proactive hedging strategy and the exceptional performance of our Fleet and Energy Marketing segment.

During the year, we delivered adjusted EBITDA of $1.25 billion, free cash flow of $569 million or $1.88 per share and average fleet availability of 91.2%. We also delivered on a number of key priorities and strategic initiatives.

First, we closed the Heartland acquisition late last year and are now in the process of fully integrating Heartland's 1.75 gigawatts of complementary assets into our Alberta portfolio. The transaction enhances our competitive position in Alberta by ensuring we maintain a robust and diversified portfolio in the province.

Second, our growth team had a strong year, completing the 200-megawatt Horizon Hill Wind facility, the 300-megawatt White Rock wind facilities and the Mount Keith transmission expansion.

We also fully completed the Kent Hills rehabilitation project. These assets will collectively contribute over $175 million in adjusted EBITDA to our company annually.

Third, we returned $214 million or $0.71 per share to our shareholders through dividends and share repurchases with our share repurchases executed at an average price of $10.59 per share.

Returning capital to our shareholders is a key part of our capital allocation strategy, which we adapt to market conditions and the timing and progress of our growth opportunities.

Our practice is to always have a normal course issuer bid in place, and we expect to continue to make accretive share buybacks in 2025 of up to $100 million. Fourth, we continue to advance the significant contracting and development opportunities that we see at our legacy thermal sites in both Washington State and Alberta.

Fifth, we continue to reduce our CO2 emissions. Since 2015, we have reduced Scope 1 and two greenhouse gas emissions by 22.7 megatons or 70% a remarkable achievement considering the size and diversity of our fleet.

And we will cease coal-fired generation from our single remaining coal unit by the end of 2025, which will further reduce our emissions.

And finally, based on our strong performance in 2024 and our confidence in the future, we're pleased to announce that our Board of Directors has approved an 8% increase to our common share dividend to $0.26 per share on an annualized basis. This represents our sixth consecutive annual dividend increase, affirming the company's commitment to returning value to shareholders.

Our balance sheet continues to provide us with strength and flexibility with over $1.6 billion in available liquidity including approximately $334 million in cash, we're very well positioned to execute our strategic priorities.

We successfully closed the acquisition of Heartland on December 4, adding 1.75 gigawatts of complementary flexible capacity to our company including contracted cogeneration, gas thermal generation and peaking generation, along with transmission capacity, all of which will be needed to support the energy transition and reliability in the Alberta electricity market. 60% of the revenues are contracted with leading counterparties with a weighted average remaining life of 15 years, providing added diversification to our cash flows and tempering our merchant exposure.

The regulatory review process for the transaction with the Federal Competition Bureau was a lengthy one and resulted in our agreeing to divest Heartland's Poplar Hill and Rainbow Lake facilities in order to complete the transaction. This led to a purchase price reduction of $80 million. The revised purchase price for the transaction was approximately $542 million, consisting of a cash payment of $310 million as well as the assumption of $232 million of low-cost debt.

An economic benefit adjustment of a further $95 million, ultimately resulted in the net cash payment of $215 million, which was funded through a combination of cash on hand and draws on our credit facilities. The overall net price, inclusive of debt, works out to approximately $270 per kilowatt and an attractive EBITDA multiple of 5.4x. And we're in the process of realizing approximately $20 million of corporate synergies on a pretax basis in connection with the transaction.

We're pleased to welcome Heartland to TransAlta and are happy with how the integration is progressing. At our Centralia site, we're exploring multiple opportunities to meet load growth and enhanced reliability in the region.

We're currently advancing discussions with the customer on a redevelopment opportunity to extend the operating life of our legacy Centralia site through a contracted coal-to-gas conversion.

We're also considering other opportunities to build out the energy campus on our significant land holdings including potentially, wind, solar, batteries, pump storage and next-generation technologies.

We expect to be able to share detailed development plans for Centralia during the first half of 2025.

We are also advancing opportunities at our legacy thermal sites in Alberta, which we believe offer ideal conditions for data center opportunities including speed to power, expansion potential, Tier four reliability, competitive power pricing and support of renewable product offerings.

Our work is progressing through three phases. The first phase, which we completed in the fall, was the socialization phase.

In this phase, we engage with potential customers, highlighting our service offerings and gauging interest in our Alberta sites. The second, technical phase, is ongoing and includes location assessments, geotechnical work, zoning and interconnection applications.

And we recently submitted our Keephills site into the interconnection queue through a 2-phase submission over the course of 2027 and 2028, permitting and engineering assessments, supply chain engagement, and the evaluation of existing fiber optic networks, water rights and cooling pond capabilities.

This phase is advancing well towards detailed and derisked commercial offerings that we can showcase to our potential customers. The next final phase is commercialization, which includes contracting with high-quality counterparties and the beginning of construction at our sites.

We aim to secure exclusivity with key partners by mid-2025, with detailed design and definitive agreements expected later in the year. We anticipate operational data centers 18 to 24 months after signing definitive agreements. Now I'll pass it over to Joel.

Joel Hunter^ Thanks, John. And good morning, everyone. We are extremely pleased with our fourth quarter and full year operational and financial performance across all of our business segments. The Alberta Merchant portfolio notably outperformed the spot market, thanks to our hedging and optimization strategies despite the ongoing challenging pricing environment.

Starting with our full year results. The Hydro segment generated adjusted EBITDA of $316 million, in line with our expectations given lower realized and auxiliary spot prices. The decline year-over-year was partially mitigated due to realized premiums above spot prices and positive contributions from hedging as well as a greater volume of auxiliary services due to increased demand by the ISO.

We are also able to sell additional environmental attributes to partially offset the power price declines at the merchant hydro fleet.

The Wind and Solar segment delivered adjusted EBITDA of $316 million, a 23% increase compared to 2023, primarily due to the addition of the Oklahoma wind assets and the return to service of Kent Hills.

The Gas segment achieved 92.2% availability and delivered adjusted EBITDA of $535 million. The year-over-year decline was due to lower power prices in Alberta and increased dispatch optimization from our Alberta Gas fleet. However the impact of lower realized prices was offset by our favorable hedge position.

The Energy Transition segment delivered $91 million of adjusted EBITDA which decreased year-over-year due to increased economic dispatch, driven by lower market prices, which negatively impacted merchant production.

Our Energy Marketing segment delivered exceptional performance with adjusted EBITDA of $131 million, an increase of $22 million or 20% year-over-year. This was due to favorable market volatility across North American power and natural gas markets.

And finally, Corporate costs increased year-over-year, primarily due to increased spending to support our strategic and growth initiatives.

Our adjusted EBITDA excludes the impact of Brazeau penalties assessed, ERP integration costs and Heartland acquisition-related costs, as these items are not reflective of our ongoing operations or performance of our operating assets.

As John mentioned, overall, we delivered another strong year with $1.25 billion of adjusted EBITDA, reaching the upper range of our 2024 guidance. Our free cash flow was also strong, delivering $569 million or $1.88 per share, also in the upper range of guidance.

Shifting now to our fourth quarter results. The Hydro segment produced adjusted EBITDA of $57 million, in line with last year. Higher merchant revenues were driven by higher volumes, which were partially offset by lower spot power prices and lower environmental and tax attributes.

The Wind and Solar segment produced adjusted EBITDA of $95 million, an increase of 16%, primarily due to the addition of our Oklahoma wind facilities and the resurgence of service of Kent Hills.

The Gas segment saw adjusted EBITDA decrease by 18% to $116 million, mostly due to lower realized power prices in Alberta and higher carbon pricing. The Energy Transition segment delivered $28 million of adjusted EBITDA, in line quarter-over-quarter.

Energy Marketing adjusted EBITDA increased by $13 million to $27 million, which is the same period last year due to favorable market volatility and timing of realized settle trades. Corporate costs increased quarter-over-quarter, largely due to higher spend to support strategic and growth initiatives noted previously.

Overall, we generated $285 million of adjusted EBITDA in the fourth quarter, in line with 2023, despite milder weather conditions that contributed to lower merchant power prices in Alberta.

Lower free cash flow of $48 million in the fourth quarter was primarily due to higher sustaining capital expenditures, which is typical for the fourth quarter, along with higher realized foreign exchange losses, higher current income tax expense, increased spending on growth opportunities and higher net interest expense due to our lower capitalized interest and interest income.

Turning to the Alberta portfolio. The 2024 spot price averaged $63 per megawatt hour, which was notably lower than the average price of $134 per megawatt hour in 2023. The decline year-over-year was primarily due to incremental generation from the addition of new gas, wind and solar supply as well as lower natural gas prices.

Our Hydro fleet delivered an average realized price of $91 per megawatt hour, a 144% premium to the average spot price. The Gas fleet also exceeded our expectations.

We deployed hedging strategies to enhance our portfolio margins and mitigate the impact of lower merchant power prices throughout 2024. We hedged 9,100 gigawatt hours at an average price of $86 per megawatt hour, 137% premium to the average spot price.

Our merchant wind fleet realized an average price of $34 per megawatt hour, in line with our expectations given the evolving Alberta merchant power market. Despite relatively benign weather last year, which resulted in lower power prices on average, we captured additional margins by fulfilling a portion of our higher price hedges with purchase power when prices were below our variable cost of production.

While optimizing our fleet throughout the year and fulfilling hedges with purchase power, we're able to respond to higher demand from the ISO and deliver additional auxiliary service volumes across the Alberta fleet.

In 2024, our average realized price for ancillary services settled at $46 per megawatt hour, approximately 75% of the average spot price. Turning to the fourth quarter. Spot prices averaged $52 per megawatt hour, significantly lower than the $82 per megawatt hour in 2023.

However our Alberta Hydro and Gas fleets continue to outperform with average realized prices of $78 and $75 per megawatt hour, respectively, a significant premium to the average spot price of $53 per megawatt hour.

Turning to our 2025 outlook. We expect that our results will be broadly in line with 2024.

For 2025, we expect adjusted EBITDA to be in the range of $1.15 billion to $1.25 billion, and free cash flow to be in the range of $450 million to $550 million, or $1.51 to $1.85 per share. Now there are a number of factors influencing our 2025 outlook.

First, we expect Alberta and Midsea spot power prices to decline to a range of $40 to $60, and USD 50 to USD 70 per megawatt hour. Second, we are well hedged both financially and through our commercial and industrial business, which I'll speak to momentarily.

Third, our outlook includes the full year impact from Heartland and our Oklahoma wind assets. Fourth, we expect our OM&A this year to be higher year-over-year due to the full year impact from the addition of Heartland as well as the advancement of our growth initiatives shaves. And finally, we expect continued solid performance from the Energy Marketing segment with a midpoint gross margin of $120 million.

The confidence in our EBITDA and free cash flow guidance is supported by the performance of the contracted fleet as well as our hedging and optimization strategies. 75% of our generation revenue is from our contracted assets and hedging position, which, along with our stable energy marketing earnings, gives us confidence in our 2025 outlook.

It is our expectation that our company will become increasingly contracted over time. Looking at this year, we have approximately 7,700 gigawatt hours of our Alberta generation hedged at an average price of $70 per megawatt hour. This is well above the current forward curve.

We will continue to optimize our fleet and reduce production in low-priced, high-supply hours by fulfilling our financial hedges and customer requirements with open market purchases.

Looking to 2026, our team has hedged production average price of approximately $75 per megawatt hour, also well above current forward pricing levels. Turning to capital allocation. We're keen to maintain a balanced, prudent and disciplined approach.

First, we are focused on keeping adjusted debt-to-EBITDA in the range of three to 4x. Second, we will return capital to shareholders through dividends, while maintaining a payout ratio of approximately 15% of free cash flow in 2025.

Growth and share repurchases will continue to compete for capital. Our goal is to maximize shareholder value, and we will assess each growth opportunity against returning capital directly to shareholders.

Our capital allocation strategy adapts to market conditions, and this year, we expect to deploy our free cash flow towards our legacy thermal sites, potential M&A, as well as our long-term growth plan.

We believe that investing in our legacy thermal energy campuses will provide the greatest long-term value for our shareholders. We also expect to continue to make accretive share repurchases with capital that we do not deploy to growth.

At the midpoint of our guidance for 2025, we expect to generate $500 million of free cash flow, which provides continued flexibility with funds to deploy in a balanced approach to capital allocation.

We are well positioned to return capital to our shareholders, while prudently pursuing growth opportunities and maintaining our balance sheet strength. With that, I will turn the call over to John.

John Kousinioris^ Thank you, Joel. As I look at our strategic priorities for 2025, we're focused on the following key goals. First, improving our leading and lagging safety performance indicators, while achieving strong fleet availability. Second, achieving EBITDA and free cash flow within our 2025 guidance ranges. Third, maintaining our high fleet availability and reputation as a world-class operator.

Fourth, maximizing the value of our thermal energy campuses. Fifth, successfully executing M&A that may arise, and advancing our growth plan. And finally, successfully implement upgrade to our ERP system.

We'll remain prudent and disciplined in our approach to growth, focusing on delivering value to our customers and our shareholders, and we look forward to sharing more with you at our 2025 Investor Day that we're planning to host in November.

I believe TransAlta offers a compelling investment opportunity. First, we're a safe, reliable operator with a highly capable workforce.

Second, our cash flows are strong and resilient, and underpinned by our diversified hydro, wind, solar and gas portfolio, complemented by our world-class asset optimization and energy marketing capabilities.

Third, we're a clean electricity leader with a focus on tangible greenhouse gas emission reductions as we remain on track to achieve our ambitious 2026 CO_2 emissions reduction target. Fourth, there is tremendous value in our legacy thermal sites, which our team is actively working to repurpose, to meet the evolving needs of our customers and markets.

Fifth, we're well positioned for growth, with a diverse set of high-value growth opportunities, our talented development team is focused on realizing for our shareholders. And sixth, our company has a sound financial foundation.

Our balance sheet is strong, and we have ample liquidity to pursue and deliver multiple growth opportunities with the flexibility to also return capital to our shareholders through dividends and potential share repurchases.

Finally, we have our people. Our people are our greatest asset, and I want to thank all our employees and contractors for the outstanding work they have done to deliver our results and strong finish to 2024. Thank you. I'll turn the call back over to Stephanie.

Stephanie Paris^ Thank you, John. Operator, Towanda would you please open the call for questions from the analysts.

QUESTIONS AND ANSWERS

Operator^ (Operator Instructions) Our first question comes from the line of Robert Hope with Scotiabank.

Robert Hope^ Just taking a look at the 2025 priorities, they include strategic M&A. When you think about kind of the geographies or asset types or modalities that you're looking at, what are most attractive and what are the least attractive?

John Kousinioris^ Robert, why don't I start responding to the question, and maybe I'll turn it over to Joel to add any color that he has.

So look, we are seeing a number of opportunities throughout North America, particularly in the United States from an M&A perspective. And broadly speaking, they fall into two categories from our perspective, is legacy Gas assets that we see operating in certain jurisdictions. And interestingly for us, Renewables.

There's a lot of focus on natural gas-fired generation right now and we're actually seeing potentially, at times, better value of Renewables side than on the gas side. In terms of the geographies, I would say that we're primarily focused on I think Joel is fair to say, kind of Western North America.

So there is Alberta, but our focus is much more on the western part of the United States with a particular focus on, I would say, the Pacific Northwest and the Desert Southwest right now as being sort of core just focus areas for our organization. We have a lot of expertise trading power in the region.

We've operated in the Pacific Northwest for a considerable period of time. And are extremely comfortable with the region and, candidly, like its long-term prospects when we're looking at load growth and all of the opportunities we see there. Joel, I don't know if you want to add anything to that.

Joel Hunter^ The only thing I would add to that, John, is we are seeing the multiples converge, as you highlighted, both for contracted renewables versus thermal generation. The kind of size that we look for is probably similar to what we saw with Heartland, kind of in that $500 million to $750 million kind of enterprise, if you will, would be ideal for us.

So again, we spent a lot of time on this. We get to see everything that comes available in the market. There's always hundreds of transactions per year. And so we remain very disciplined and focused, as John highlighted, on kind of more geographical focus in the West with being really technology-agnostic.

Robert Hope^ All right. Really appreciate that color. And then maybe just moving over to the Keephills data center development. You're now in the technical kind of phase. Can you maybe add a little bit more color on what you think a potential outcome could be here?

Is this just bringing back some existing or improving the reliability and kind of utilization of existing capacity? Or could there be something more fulsome here including further developments? Can you maybe just put some outcomes of what this could look like?

John Kousinioris^ Yes. Happy to. I think the way we're thinking of it is actually in -- I think it's fair to say, a 3-phased approach. So Keephills would be the initial campus that we're focused on as an offering for data centers, followed by Sheerness.

So we're quite pleased by what we're seeing at Sheerness from a potential perspective. And then with a focus after that, more around Sundance, which is probably, Joel, I think it's fair to say more in the vein of a bit more of a redevelopment piece there for Sundance.

Right now we would envision -- and the work that we're doing is primarily around Keephills two at the moment as an offering. The idea would be that, that unit would provide, notionally, behind-the-fence extension for a data center but with a connection to the grid.

So 90% or so would be powered essentially from our unit there, with the remaining 10% of reliability coming off of the grid. The work we've done is pretty extensive.

We have a lot of the opportunity mapped out, everything from geotechnical work in terms of where the data center actually locate, if they actually require quite a large footprint in terms of what they would require, right through to looking at how the water would flow to cool the facility, how the electrons would flow either from the grid or from the facility to a substation to be stepped down to actually work for the facility.

We've done zoning work there. The county is very, very supportive, and we have a real good handle on the fiber network and what its capabilities are.

So we're optimistic. But our goal is to be in a position where we have really done an extensive set of preliminary work to make kind of the commercial offering and the technical assessment for our customers as easy as possible.

So we're front-ending deliberately from our perspective as much as we can in terms of the offer that we'll be providing. And our discussions continue.

Operator^ Next question comes from the line of Mark Jarvi with CIBC.

Mark Jarvi^ I just wanted to continue on the call conversation we just -- you had there, John. In terms of like the counterparties, you said kind of your obviously folks in the technical work.

But are the range of counterparties for data centers, is there a number of them that you're talking to right now? And it sounds like given you said 90% served by Keephills unit 2, you're kind of in a 400-megawatt type load. Is that a fair number for the first sort of phase of data center deals?

John Kousinioris^ Mark, I'll answer the second part first. The answer to that is yes, that is what we're looking at. Initially, the initial offering would be 400 megawatts from K2 followed by another 400 megawatts at K3, which is the way we're looking at phasing it.

In terms of the customers, look, we've been having conversations for a period of time. We began with our first phase and it's continued with our second phase.

Without getting into specific numbers, like our universe of potential customers is in kind of the range of about 20, I would say. They include both hyperscalers and co-locators, and we have had discussions with both. And we continue to -- be as constructive as we can to meeting their particular needs.

So that's -- hopefully, that gives you a bit of a sense of the way that we're working through it.

Mark Jarvi^ And have any of those conversations evolved at all in spite of -- or sorry, in light of what's happened in the last couple of months here, whether it's tariffs, economic uncertainty in Canada, a little bit of like tension across the border? Is that changing anything pending the conversations though?

John Kousinioris^ Yes. It's a great question. Not that we have seen. I'm looking at Blain here, too. Blain, I can't I can't think of it really driving either the work that we're doing or, candidly, the discussions that we're having with potential customers. The one thing that we're focused on, though, is just from a supply chain perspective.

I mean if there are tariffs, we're just being mindful about time to actual delivery of some of the key components that we require. And that's mostly around the substation and the transmission.

It's less about the actual facility itself and what that might mean from a cost perspective. I don't think it really changes the economics all that much in terms of the aggregate offer that we're providing though.

Mark Jarvi^ Okay. And then turning to Centralia. In terms of when you kind of land on agreement, any sense of the capital required to reposition that asset? It sounds like the coal-to-gas conversions first phase, maybe some larger energy campus.

In terms of how then the asset then ultimately progresses after the end of this year, is it sort of down for 2026 and then back up in 2027? Just sort of the timeline and then maybe the capital required for that turnaround.

John Kousinioris^ Yes. Why don't I start and then I'll get Blain to maybe fill in. So look, on that one, without getting into specifics on what the capital would be -- and by the way, we have done quite a bit of engineering and have a handle on what the capital would be.

I mean there's basically three prongs of work that we need to do there. One would be the actual version itself, and that's largely dealing with the burners. The cold burners turning them into gas.

Secondly, there will be some control work that we need to do. And thirdly, you have to remember, and Blain always reminds me of this, we were harvesting the plant in the latter phases of its life.

So there is a bit of maintenance work, I'd say, Blain, that we need to do to bring it up to a place where that would be able to run for well over a decade going forward.

The cost of doing that work would be a fraction of what it would cost to do a new build. And when I think of that, it would be in the order of, I don't know Blain, around 25%, probably maybe a third of what a new build would be. So hopefully, that gives you a bit of a sense. Blain, I don't know if you want to add any color.

Blain Van Melle^ I think that's right. And if you remember, Mark, we have a lot of experience doing conversions with all the units we did here in Alberta.

So we're building off that work and using the same teams that we did that, the kind of value engineer project at Centralia and come out with the best capital that comes up we can.

John Kousinioris^ And then just on the timing, Mark, the unit would shut down at the end of '25 in terms of coal-fired generation. And then it would be down for 2026 for us to do a bunch of the work that we need to do and make sure our gas supply is set up appropriately. And I think Blain, realistically, it would be a 2027-ish kind of return to service, I would think, in its new kind of form, roughly speaking.

Mark Jarvi^ And then, John, what's the Gas supply constrain and on how much capacity then you could actually provide to the customer right now?

John Kousinioris^ Yes. I think -- so the customer has gas supply. I think it's -- and transportation. I mean the pipeline is literally across the street from our facility. I think we would view this in a phased kind of approach, and I think that we're working with them to come up with a way that the gas supply wouldn't be an issue.

A little bit of a constraint probably blame in the first three to five years, I would say. And then the expectation would be that it would be unconstrained thereafter, but we're working to kind of debottleneck it even in the initial period.

Mark Jarvi^ And can you put a sort of a megawatt of capacity around what the gas supply could enable right off the gate?

John Kousinioris^ So the unit would be there to backstop reliability in the region. And our intention right now is to have the 670 available. The gas supply issue would be how often it would be able to run at full tilt as opposed to the size of what the unit offering would be.

But the capacity factor for the unit, it's not like we're talking 50%, it would be significantly below that in terms of providing reliability given the intermittency that we're seeing in the region there.

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

Maurice Choy^ Just wanted to follow-up on that potential M&A of legacy gas assets in the U.S. Absolutely recognizing that you haven't announced anything, it may not have even happen, and you already have some trailer in the region as well.

But just thinking holistically, what is the strategic aim here? Like I wonder is it to create a platform to grow in a nonrenewable LNG way in the state? Is it to capture the growth in electricity in the states? Help me understand that, please?

John Kousinioris^ Yes. So I'd say from an M&A perspective, Maurice, I think you've actually kind of got it right. So what we have done is we've looked at our organization and looked at what our particular skill sets are. And we have a number. But two of them that are quite striking, at least from our perspective, is we do have the ability to run all types of generation.

Our ability to run generation in a technology-agnostic way is excellent, too. We're very good at dealing with customers and being able to provide solutions to them directly.

And then finally, our trading and energy marketing expertise is super strong and a differentiator. A number of people do realize this. I mean we're the largest trader in the Pacific Northwest, for example, in Mid- Sea in terms of power.

We have transmission that goes up and down the West Coast, and we've spent literally years and years moving power from the Desert Southwest up through California into the Pac Northwest and back down again.

So we think that, that is a region, that with the expertise that we have and kind of the overall long-term growth prospects that it has, that we can have a significant position in and be able to do extremely well for our shareholders.

So it's really about mirroring opportunity in the region and aligning it with the internal skills and capabilities that our organization has to create for our shareholders. And I think it will be a mix of greenfield, brownfield and, frankly, legacy assets that we could get from an M&A perspective. So that's, in essence, what we're trying to do.

Maurice Choy^ Understood. And maybe if you could just bring it all together and looking at all the options that you have from Keephills to M&A to share buybacks. You mentioned -- I think Joel mentioned that the target debt to EBITDA is three to 4x in that range.

Can you share how much investment capacity you have before reaching the higher end of that range? And I think in the past, you also mentioned potentially seeking an investment-grade credit rating, is that still on the table?

Joel Hunter^ Yes, Maurice. I'll start with the investment-grade rating. As a reminder, we do have an investment-grade rating today with DBRS. We are at BBB low, with a stable outlook with them. And we are BB+ with a stable outlook with both Moody's and S&P.

They've asked us that in the past, would we want to go to investment grade, and our view right now is that the sweet spot for us, if you will, it gives us the most financial flexibility is to maintain the BB rating with both S&P and Moody's, and the BBB- rating with DBRS. And with that comes a range of, as we've highlighted, around three to 4x.

We exited last year at 3.6x, so we do have some capacity here going forward. And as the balance sheet grows, that we'll see additional capacity come with it. The one item, too, is the Brookfield convertible option, if you will, into the hydros. The agencies treat that as debt today.

If Brookfield were to convert that option between now and the end of 2028, while the option is available to them, that does free up additional capacity as well.

So when we look at where we sit today with our debt to EBITDA around 3.5x and we look at a strong free cash flow generation, I think it looks very similar to where we were last year, Maurice, as far as the amount of capacity that we have.

So if you think about for the Heartland acquisition, where we were able to fund that with our free cash flow along with draws on our credit facility.

So when we think about what we can spend going forward here, kind of living with inter means, without looking to any portfolio management or rotation, if you will, or common share issuance, you're kind of in that $500 million, probably to $750 million that we could spend.

Maurice Choy^ Just to be clear, whilst your -- the $500 million to $700 million, you said living with any means. Are you -- you're not ruling out asset sales and/or equity issuances to sell the growth that you have there?

Joel Hunter^ We're not, Maurice. Not at all. What I'm saying is that right now just based on what we see in front of us, whether it's with data center opportunities here in Alberta, along with the Centralia opportunity, along with kind of what I call bite-sized, if you will, M&A opportunities, we think we can do all that with living within our means.

To the extent that we see bigger opportunities we'd certainly look to rotate capital and/or issue common equity. But again, as a reminder here, it has to be accretive to the shareholders.

It has to be accretive to our earnings per share, to our cash flow per share. It has to be within strategy. It has to be underpinned by a long-term contract. It has to check all those boxes before we look to rotate capital.

But certainly, if we see an opportunity where we can own an asset at 11x and redeploy that into something at 6x, we'll do that. A really great example that was Heartland. We bought that at a 5.4 turns multiple. Again, if we see those types of opportunities, we'll do that and look to rotate capital.

John Kousinioris^ Yes. I mean we've got 88 facilities, Maurice, now in three different countries. And some of them are less, I would say, strategically important than others, being candid about it. So I think we've got quite a bit of flexibility. The other thing I would say, Joel, is that the legacy asset opportunities have a bit of a slower burn.

In other words, it's not like you're doing an acquisition where you need to come up with $500 million to execute it today. Dealing what we're dealing with here in Alberta from a thermal asset perspective and also dealing with the opportunity we're seeing in Centralia, it's a bit more butter spread over a couple of year period. So we do have capacity.

Operator^ Our next question from the line of Patrick Kenny with National Bank.

Patrick Kenny^ Maybe just first on your free cash flow guidance. Interest expense is up year-over-year, for obvious reasons, but so is sustaining capital. So I was just wondering if you could provide a bit more color on the key drivers there. And then I guess as we look into 2026 and beyond, how your sustaining cap budget might evolve, at least directionally, towards a more normalized run rate?

John Kousinioris^ Yes. Patrick, you're right, our sustaining capital kind of in that $145 million to $165 million in terms of the guidance we're guiding for 2025 is a little bit higher than it would have been over the last few years, we were plugged by -- in the range of around $20 million or so. That is reflective -- or the increase is reflective of two things.

One of them would be candidly the issue of the Heartland assets into the organization, which we're going to, we've added 1.7 gigawatts of generating there.

We need to maintain that, and that's something that we're going to need to do as part of the normal course of the operations of those facilities, which has an impact on, I'd say, our run rate, Joel, from a capital spending perspective.

And we're also doing a little more of what we would call life extension/dam safety spending, I think, is what you would see that we're doing.

I mean our -- those facilities are perpetual facilities from our perspective. And we're in a place where we have a few projects that we're focused on doing and we're executing on that. I think those are really the main drivers I'd say, Joel.

Joel Hunter^ Yes. And Pat, I think your point on interest expense, we did see that higher in fourth quarter year-over-year due to us closing the Heartland acquisition, along with just more cash balances. And our guidance here, we're seeing kind of our interest expense to be probably about $15 million higher kind of year-over-year compared to where we were in 2024.

John Kousinioris^ And maybe one more thing, Patrick. We're taking a pretty conservative approach in our growth expenditures. So I think there would have been a time in the past, we would have sort of capitalized maybe a little bit more of that.

We're going to do that at a later stage, I'd say, in the development life cycle of a project and having some of those expenditures kind of flow through in the year. That isn't a big driver, but it's a little bit of a change from our perspective, I'd say.

Patrick Kenny^ Okay. I appreciate that. Shifting gears. Any update on the AESO's proposal or process here to look at securing strategic reserves?

And as things have progressed on the data center front, how you might be thinking about the relative value of contracting any of your CTG assets, either the ones that are operating or mothballed with the AESO, as opposed to holding them back and being available for contracting with any private behind-the-meter customers?

John Kousinioris^ Yes. So look, on the -- just broadly speaking and very quickly, just on the ramp on the market redesign, and Blain can jump in here as well. I would say that, that is progressing. There's a lot of work to be done.

I think we've seen kind of the first sort of overall proposal that the ISO is looking at for the market construct plan, I guess, late last year, and there's been input that's been provided and that engagement continues.

Thematically though, I would say, we're seeing in the market construct, particularly with the development of kind of that day-ahead market, a construct that favors dispatchable generation. Generation that has capacity that can provide into the market.

So given the mix of fleet that we have in the province of Alberta, that bodes well certainly for a Gas fleet and our Hydro fleet as we go forward. So from that perspective, it's positive. In terms of the more direct issue of where would you direct your thermal generation. I mean Hydro would be a premium product.

We believe there is more value in having those units around to contract directly with customers from a data center perspective than earmarking them for, let's just call it, broadly reliability products. And that's what our current focus is. There was a bit of a discussion, for example, about reliability contracts earlier on that would have had as a requirement that a unit be taken off, for example, from the end of that period of time.

That's not something that I would say, Blain, we're all that particularly interested in. I think there's tremendous option value in the fleet. And right now given our hedging ability, we'd rather have our units available to just operate in the market.

We like what we're seeing from a day-ahead perspective, incentivizing dispatchable generation in the market design going forward and really working to meet data center needs. I don't know Blain, anything to add there?

Blain Van Melle^ The new utility service products, the ramping products, that would favor our peaking capacity as well as our hydro facilities. So a lot of like John mentioned, market design components that favor dispatchable fast-ramping generation that we kind of positioned our fleet for.

Patrick Kenny^ Okay. And then a follow-up in terms of offering a green option for your potential data center customers in Alberta.

Can you just walk us through the various ways you could help your customers decarbonize their footprint over time and how you're thinking about bearing the cost or sharing the risk related to the industrial carbon tax going forward?

John Kousinioris^ Yes. Maybe a couple of things there. So first of all, we have a significant portfolio of environmental attributes and that portfolio is supplemented every year as our wind generation and hydro generation operates in the province of Alberta, which is helpful, I think, from an industrial carbon pricing perspective.

Which I think, Patrick, it's probably fair to say, is a bit of a question mark as we go forward, given where Ottawa might be going 2, 3, 4, five months from now and how that trickles down into the province.

More directly, we do have merchant wind generation in the province of Alberta, which uniquely we have and are able to kind of bundle with the offerings that we have, for example, at Keephills to create a greener product. And then finally, we also have projects that we had put a bit on hold given the uncertainty around them that we can bring to also provide green power to supplement the data center. And Tempus is a great example of that, a 100-megawatt wind arm that we can bring on.

We've continued to advance that product so that it can be available. And we even have a bit of work around doing potential solar, up at the old mine sites that we have in West Central Alberta.

So it's a combination of things that we're working through to kind of provide that option to the extent it's required. And we think longer term, it will be, candidly.

I think the focus right now is on speed to power and reliability, and thermal is a critical component of that. But I -- we haven't lost, I'd say, Blain, kind of the thread on the need to be responsible from a decarbonization perspective overall.

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

John Mould^ Maybe just continuing on the Alberta theme here. Just on where you're seeing surplus capacity in the province right now? I think you previously characterized it as around one to 2 gigawatts. How has your thinking evolved based on the generation dynamics you've seen so far this year with the new supply?

And you've got the pending mothballing at Sun 6? And does the gas builds on the data center front, from your perspective, is that potentially directly drive the need for that Sundance site redevelopment over the midterm, whether it's more gas conversions or potentially bringing back to Sun five repowering? Like how are you thinking about all those moving parts in the broader supply dynamic in the province?

John Kousinioris^ I think we could probably spend hours responding to that question, but let me try. So we do think the market is oversupplied at the moment, and we've got 23-and-a-bit thousand megawatts of installed capacity. And we peak at around, call it, 12,000, sometimes a little bit more. Kind of between 12,000 and 13,000. So there is quite a bit of supply in the province.

And then when we think of, for example, load growth in the province, which we do think will occur, for example, from data centers, I think the market can comfortably absorb one to 2 gigawatts.

Some number in that range. That would be a TransAlta view in terms of what it can absorb. And keep -- and that has two things associated with it.

One, I think reliability of the market stays intact, which I think is critically important not just to the ISO, candidly, it's very important from a TransAlta perspective, if that's the case. And secondly, there is the generation to be able to just deal with that from a speed to power perspective.

And people have heard the Premier say people need to bring their own power. From our perspective, having units that are more in the vein of peaking units, which with capacity factors that are below 50%, like our coal to gas units up in the region, are ideally suited to actually meeting that need. And that they can flex up and actually provide additional capacity in the market when it's needed.

I think kind of new generation -- and by the way, as the data centers come in, I think it helps to rebalance the supply and demand imbalance that exists today in the marketplace with more constructive pricing. And because I think where we are today is not -- I think pricing, that incense new generation coming into the province.

In terms of the redevelopment opportunity, we do see that more in the 2030s. I think we need to see what's going to happen in terms of the REM and how it's going to perform.

I think you're going to see quite a bit of natural gas retiring, just end of life, candidly, in that time period beginning in the early 2030s. And we're also looking to see how technology develops. Is it gas?

Is it hydrogen? Do we need dual fuel capability? How does that progress as we go forward? So it is a bit of a longer timeframe, I would say. Blain, I don't know if you want to add any color to that, but that's just a thumbnail sketch.

Blain Van Melle^ No. I think that's pretty good, John.

John Kousinioris^ Hopefully, that helps, John.

John Mould^ No. That does. And then maybe just on the REM, like the higher level framework, I think it's fair to say is known, but still lots of details to sort out. Are you expecting there will be sufficient clarity on those details later in the year and the market structure elements so that both you as an IPP and large loans and the hyperscaler, co-locators are comfortable signing for agreement? Like do you see that as a barrier? Is the REM and its progress a barrier at all to those deals being finalized?

John Kousinioris^ Yes. I don't -- at least we're not seeing it right now as being a barrier. And candidly, our strategy is by doing the work that we're doing candidly in Centralia here in Alberta, we're really focused on contracting our assets.

So I think you'll see over time our merchant exposure probably declined. But Blain, I know you're in those discussions as well as I am. I mean just your view on that. I'm not sure it's...

Blain Van Melle^ No. I think that's right, John, is that we are trying to insulate ourselves from market events and market design elements while contracting the assets as best we can.

On the timing comment, John, that you asked about, we -- I would expect that as we progress through 2025, those higher-level design elements will be further refined. It will have a good sense of what those actually look and what the impacts will be.

We are doing our own modeling even with the higher level of design elements right now to understand the impacts, both on our fleet and how we can communicate that to potential customers and what we should be focused on.

And when I say the timing, we'd expect to be kind of moving through 2025 and getting to the stage by the end of the year where we have a pretty clear picture, is that the implementation plan that the ISO has to get market kind of running in the shadow market type of framework so that they can fully implement by the end of 2027, needs to start happening at the end of this year.

John Mould^ Okay. Got it. Maybe one last one on renewables. How much of your BD time being spent on potential renewable projects versus thermal site optimizations, acquisitions? And not asking for you to preview the November Investor Day right now but just looking for a sense of how you're broader corporate thinking around capital allocation towards renewables versus thermal is evolving.

John Kousinioris^ So I would say -- trying to answer that. So I would say our M&A team is busy right now. I would say in terms of our commercial and business development teams at (inaudible) large, the majority of their time would be spent on extracting value from the legacy facilities. That -- so those returns are really constructive returns, and it's a real focus for the organization. We think it benefits our shareholders the most.

So renewables development would be the minority at the time that we're spending right now. And that's not just progressing projects. I think we often lose sight of this. That team is also the one that is more focused on the renewables, also focused just on pipeline.

So we think we're in a phase where legacy assets and I would say, thermal-related opportunities are kind of where our sweet spot is in kind of the immediate foreseeable sort of future, M&A aside.

And then kind of more into a normal cadence where you would see renewables coming in a little bit later in the decade.

So hope that gives you a bit of a set on the -- like I think it's critical for growth teams to be able to pivot towards the best opportunities that they see in front of them in the particular period, and that's exactly what we've done. I think that will be critical going forward.

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

Benjamin Pham^ Just going back to the Alberta redevelopment opportunities. As you have conversations with the counterparties, (inaudible) or so you've mentioned, do you get to set that the amount of megawatt needs way outstrip supply? Or anything that you can provide?

John Kousinioris^ It's hard to answer that question, honestly. I think maybe the best way to answer it is sort of twofold.

I think the offering that we have, and in particular beginning with sort of 400 megawatts at K2, is more than adequate, I would say, for meeting the needs of a very substantial data center presence in the region.

I'm just going from memory, you also need about an acre of, I think, roughly speaking, for every megawatt of generation to kind of build out effectively as part of this. So land supply is critically important.

So I don't think we're constrained in terms of what we're proposing at Keephills, for example, both with K2 and K3 in terms of meeting the need of a customer and that would be very impactful to our company.

We're not seeing -- on a more macro basis, we're not seeing any lapse in the increasing load data centers, AI-driven electrification generally, I would say. And I think thematically, we're seeing jurisdictions be short power.

Like whether -- if anything, what's interesting about Alberta, it's actually a bit long power compared to many jurisdictions. And when we look at kind of the immediate jurisdictions around us and even looking at places like North Virginia and places like that, people are short power.

So the time it takes to get to market or get to the end state where you can kind of plug in and do is really long. And I think that's an advantage that Alberta has and that we haven't in particular.

Benjamin Pham^ Got it. And can you walk through -- you mentioned transmission connection application in-service states and whatnot. Can you talk about beyond the connection? Is there -- what's the regulatory process beyond that?

John Kousinioris^ So there's a few things that we need to have in place, and they range everything from -- just to give you a sense of the work that is required, everything from rezoning the land that we have there so that it is appropriate to be used for a data center.

We actually have a road we need to close. So we need permitting and relaxations around that. We need to be able to go through the interconnection process, which go through multiple stages.

I think the first stage is pretty straightforward, Blain. There's, I think, three or four stages that you need to go through. It would take some time months to be able to see that through.

What other purpose do we need? A building permit, frankly, to be able to get the data center build. Our assessment is that the time to actually -- getting to where we need to go. The critical path item isn't really the permitting process.

I think the critical path item for us is making sure that we can get things like breakers and transformers, candidly, to be able to move the power from our plants, the distance, which isn't a long distance, that would go to the site that would be ideal for the data center to locate. And from a high-voltage out of the plant to be stepped down to the appropriate voltage to go down into the data center. That's a critical path item.

Like getting transformers and breakers, I don't know Blain, 18 months, two years, to get some of that done.

We know that the build of the data center itself is roughly a 2-year time period, 18 months to two years. So there is broad alignment around that. And we're actually thinking about maybe going out and ordering some of that equipment just so that we can get ahead of the queue.

Benjamin Pham^ Okay. Got it. And just one more, if I may. You referenced Tier four reliability, and that's actually pretty much no downtime. Is the requirement then for K2, K3 to -- is it more availability above 90% and then the BTF affected buys the difference from the spot market or some other source?

John Kousinioris^ That is correct. You broke up there a little bit, but I think you're 100% right. So when we think of Tier 4, you're right, it's 99.999%.

I think it's 99.999% in terms of what the availability is. So the work that we have done is what do we need to do to make sure that our unit will be available, I'd say, Blain, roughly 90% of the time.

And that engineering work is done. And that's not as far off on where frankly, the unit is now with the residual 10% coming from the grid to be able to give you that additional 10% of availability that you need.

I'd say there's also a difference in the customer. I think with the hypescaler, they do want to have that availability all of the time no matter what.

With the co-locator, sometimes your flexibility to be able to deal with things like maintenance and maybe a shape to the availability periodically is a little bit better. But then I think the way you articulated is exactly right.

Operator^ Ladies and gentlemen, I will no further questions in the queue. I would now like to turn the call back to Stephanie for closing remarks.

Stephanie Paris^ Thank you, everyone. That concludes our call for today. If you have any further questions, please don't hesitate to reach out to the TransAlta Investor Relations team.

Operator^ Ladies and gentlemen, that concludes today's conference call. Thank you for your participation. You may now disconnect.