Q2 2024 Earnings Call

Company Participants

- David McFarland, Vice President, Investor Relations & Treasurer
- Diane Leopold, Executive Vice President and Chief Operating Officer
- Robert M. Blue, Chairman, President and Chief Executive Officer
- Steven D. Ridge, Executive Vice President and Chief Financial Officer

Other Participants

- Constantine Lednev, Guggenheim Partners
- Jeremy Tonet, J.P. Morgan
- Nicholas Campanella, Barclays

Presentation

Operator

Welcome to the Dominion Energy Second Quarter Earnings Conference Call. At this time, each of your lines is in a listen-only mode. At the conclusion of today's presentation, we will open the floor for questions. Instructions will be given for the procedure to follow if you would like to ask a question.

I would now like to turn the call over to David McFarland, Vice President, Investor Relations and Treasurer. Please go ahead.

David McFarland {BIO 20946446 <GO>}

Good morning, and thank you for joining today's call. Earnings materials, including today's prepared remarks, contain forward-looking statements and estimates that are subject to various risk and uncertainties. Please refer to our SEC filings, including our most recent annual reports on Form 10-K and our quarterly reports on Form 10-Q for a discussion of factors that may cause results to differ from management's estimates and expectations.

This morning, we will discuss some measures of our company's performance that differ from those recognized by GAAP. Reconciliation of our non-GAAP measures to the most directly comparable GAAP financial measures, which we can calculate, are contained in the earnings release kit. I encourage you to visit our Investor Relations website to review webcast slides as well as the earnings release kit.

Joining today's call are Bob Blue, Chair, President and Chief Executive Officer; Steven Ridge, Executive Vice President and Chief Financial Officer; and Diane Leopold, Executive Vice

President and Chief Operating Officer.

I will now turn the call over to Steven.

Steven D. Ridge {BIO 20475546 <GO>}

Thank you, David. And good morning, everyone. I'll start with quarterly results on Slide 3.

Second quarter operating earnings were $0.65 per share, which included $0.03 of help from better-than-normal weather in our utility service areas. Weather normal operating EPS was $0.62. Relative to Q2 last year, positive factors for the quarter included $0.11 from improved weather, $0.10 from regulated investment growth, and $0.17 related to Millstone, including $0.13 from the absence of extended duration outages, and $0.04 due to higher realized power prices.

Recall that during the second quarter last year, we experienced both planned and unplanned outages at Millstone. The other material factor for the quarter was an $0.08 year-over-year hurt associated with the revenue reduction at DEV related to moving certain riders into base rates as a result of legislation that became effective in July of last year. A summary of all drivers for earnings relative to the prior year period is included in Schedule 4 of the earnings release kit.

Second quarter GAAP results were also $0.65 per share. Assessments between operating and reported results include the net benefit from discontinued operations primarily associated with the sale of the gas distribution operations, as well as unrealized and non-cash market-driven changes in the value of nuclear decommissioning trust funds and economic hedging derivatives. A summary of all adjustments is included in Schedule 2 of the earnings release kit.

Turning to guidance on Slide 4, we're reaffirming all of the financial guidance we provided at our March 1st investor meeting. First, 2024. We continue to expect 2024 operating earnings per share to be between $2.62 and $2.87, with a midpoint of $2.75. Year-to-date operating earnings are consistent with the illustrative quarterly earnings cadence ranges that we provided on March 1st.

Looking ahead, we expect that better-than-normal weather during the first half of July, combined with the $0.03 of weather help in the second quarter, will nearly offset the $0.06 of weather hurt we experienced in the first quarter. During the second half of the year, we expect to see some headwinds from higher-than-budgeted short-term interest rates and backloaded O&M expense, which puts us on track for the midpoint of our guidance range. A summary of the year-over-year drivers and illustrative EPS cadence for the third and fourth quarters is replicated from our March 1st meeting in today's appendix.

Turning to 2025 through 2029. We are reaffirming our guidance for 2025 operating earnings per share of between $3.25 and $3.54, inclusive of approximately $0.10 of RNG 45Z credit income with a midpoint of $3.40. We also continue to forecast an operating earnings annual growth rate range of 5% to 7% through 2029 off a midpoint of $3.30, which excludes the impact of the RNG 45Z credits. As a reminder, we continue to expect to see variation within our annual

5% to 7% growth range as a result of the Millstone refueling cadence, which requires a second planned outage once every third year.

As relates to 2025 specifically, earlier this week, PJM published the clearing prices in the 2025-2026 planning year base residual auction. Elevated capacity prices at the RTO and DOM Zone affirm what we've been saying for the last several years, that robust investment in an all-of-the-above generation resources and new transmission infrastructure is critical to reliably serve the growing needs of our customers in Virginia.

As a vertically integrated utility, we have a natural hedge in that the capacity purchases to serve our load are mostly offset by the capacity revenue our own generation receives. As a result, customers do not have material exposure to the outcome of the capacity market, and therefore, higher prices do not automatically translate into higher customer costs. At the time of our most recent biennial rate review, net capacity expense represented only about 1% of customer bills. Since then, we've seen a variety of actual and potential bill drivers, like the elimination of the RGGI Rider, that have the potential to significantly mitigate any net effect of higher capacity expense on customer bills. And remember, currently, DEV's rates are approximately 22% below the national average.

We'll have a holistic view of customer bill impacts when we file our next biennial case next March, with rates effective by the end of the year. Until those new rates become effective, and as a result of a small, short-generation position, we expect the impact from higher capacity prices in the second half of 2025, relative to our prior assumptions, to be about a $0.04 headwind in 2025, which we fully expect to overcome. That's a temporary impact, but big picture, this is a clear and forceful signal of the continued need for robust levels and investment in our system for many years to come.

Finally, and for the avoidance of doubt, no changes to any of the financial guidance we provided on March 1st, including earnings, credit, and dividend guidance.

Turning now to a status update on our business review debt reduction initiatives, as shown on Slide 5. During the review, we announced transactions that represent approximately $21 billion of debt reduction. With the closings of the Cove Point, East Ohio Gas, Questar Gas, and Wexpro sales, and completion of the DEV fuel securitization, we've now achieved 72% of our business review target. We're making excellent progress towards timely closing of the two remaining debt reduction initiatives, the sale of Public Service Company of North Carolina to Enbridge, and the non-controlling equity financing by Stonepeak in the Coastal Virginia Offshore Wind Project.

Let me provide a little more color about what to expect here. As relates to PSNC, all parties reached a comprehensive settlement in late May, followed by an evidentiary hearing on June 11. On July 24, the joint proposed order was filed with the commission, representing the final procedural step. We expect a final commission order during the third quarter, with closing to follow shortly thereafter. And as relates to CVOW, we received Affiliates Act approval, representing the first of two required Virginia approvals from the State Corporation Commission on June 26.

Last week, SCC staff filed their comments on the Transfers Act and Financing Partner Petition, the second of two required Virginia approvals. No other parties filed comments, and we consider the staff comments to be constructive. A hearing is scheduled for August 27, and we expect a final order later this year.

In North Carolina, the financing requires Affiliates Agreement approval. This week, the NCUC public staff were the only party to file comments, and we consider their comments to be constructive. Next steps will be commission hearings, if requested, followed by a commission order. We continue to expect the CVOW financing partnership to be completed by the end of the year, and we look forward to continuing to work with all parties involved.

Turning to financing on Slide 6. Since our last call, we successfully issued $2 billion in enhanced junior subordinated notes. These tax-deductible securities received 50% equity credit from the credit rating agencies. We've also issued approximately $400 million of equity under our ATM program, representing 80% of the midpoint of our annual guidance, as well as roughly $100 million under our DRIP programs. Consistent with our prior guidance during the remainder of the year, we'll complete ATM and DRIP issuance, complete a final long-term debt issuance at DEV, and utilize proceeds from the closings of the PSNC sale and the CVOW partnership financing to further reduce debt and lower interest expense.

In conclusion, I'll reiterate that I am highly confident in our ability to deliver on our financial plan. The post-review guidance has been built to be appropriately, but also not unreasonably conservative to weather unforeseen challenges that may come our way.

And with that, I'll turn the call over to Bob.

Robert M. Blue {BIO 16067114 <GO>}

Thank you, Steven. Good morning. I'll begin my remarks by highlighting our safety performance.

As shown on Slide 7, our employee OSHA injury recordable rate for the first half of the year was 0.38, reflecting the continued positive trend from the last two years. This is a good start, but safety is much more than just a number on a page. It's our first core value and represents the well-being of our people. Our focus continues to be on driving workplace injuries to zero.

Moving now to CVOW. The project is proceeding on time and on budget, consistent with the timelines and estimates previously provided. Let me start by highlighting the exciting progress we've made on monopile installation. Thus far, we've taken receipt of 72 monopiles at the Portsmouth Marine Terminal, representing 40% of the project total. Our partner EEW continues to make excellent progress, and we expect deliveries to continue steadily in coming weeks.

As shown on Slide 8, we began monopile installation using DEME's heavy crane vessel, the Orion, on May 22. As of yesterday, we successfully installed 42 monopiles. After a startup period, during which we successfully calibrated our sound verification process in accordance with our permits, we've been able to ramp the installation rate markedly, including achieving two monopile installations in a single day on July 21, and again on July 28.

Last week, the project welcomed a second bubble curtain vessel, an important ancillary installation vessel. A bubble curtain is deployed around the pile driving site during every monopile installation as depicted on Slide 9. The second vessel will effectively reduce time between installations.

In summary, we're confidently on our way to achieving our goal of 70 to 100 monopiles installed during the first of two planned installation seasons. In another important milestone, installation of scour protection for the monopiles began in June. We've started work on 23 monopiles to-date, which is consistent with the final project schedule.

Turning now to Slide 10 for a few additional updates. On permits, we have received all federal permits. This is unchanged. On materials and equipment, we're on track and making excellent progress. Two of three offshore substation topside structures have been completed and delivered to Semco in Denmark for outfitting. 33 transition pieces have been fully fabricated, and 15 have been delivered to the Portsmouth Marine Terminal. All 161 miles of onshore underground cable has been manufactured, and about half of the 600 miles of offshore cable has been produced. In fact, we expect to begin installing the export cable later this quarter.

Schedule for the manufacturing of our turbines remains on track. Fabrication of the towers for our turbines began in June. It's worth noting that even though we won't begin turbine installation until 2025 per our schedule, DEME recently finished supporting a monopile installation campaign for Moray West, a project off the coast of Scotland that has now successfully installed the same Siemens Gamesa wind turbine model that CVOW will use. Roughly half of the turbines have been installed, and the first turbines are already producing power. The lessons learned from that project will benefit our project installation in the future.

Moving onshore, construction activities remain on track, including civil work to support overhead lines, horizontal directional drills, and duct banks to support the underground work, and bores where the export cables come ashore. On regulatory, last November, we made our 2023 Rider filing, representing $486 million of annual revenue, and a final order was received on July 25 approving our revenue request.

Turning to Slide 11. The project's expected LCOE is unchanged at $73 per megawatt hour. Project to-date, we've invested approximately $4.5 billion and remain on target to spend approximately $6 billion by year-end 2024. Per the quarterly update filing today, current unused contingency is $143 million compared to $284 million last quarter. Use of this contingency is as expected. I'd just note that the current unused contingency is a percentage of the remaining project costs at 3% is equal to the same percentage as the time of the original filing in November 2021, despite being some 33 months further along with the project.

The current contingency level continues to benchmark competitively as a percentage of total budgeted costs when compared to other large infrastructure projects we've studied and ones that we've completed in the past. We've been very clear with our team and with our suppliers and partners that delivery of an on-budget project is the expectation. Lastly, the project is currently 33% complete, and we've highlighted the remaining major milestones on Slide 12.

Let me now provide a few updates on Charybdis. Since May, we've installed the main crane structures and the helideck structure as shown on Slide 13, and the upper leg construction continues on track. We've commenced the main engine load testing, which is on track. In the coming weeks, we will perform main crane load testing.

Turning to Slide 14. The vessel is currently 89% complete, up from 85% as of our last update. There's no change to the expected delivery timeframe of late 2024 or early 2025, which will be marked by the successful completion of sea trials, after which the vessel will return to port for additional work that will allow it to hold the turbine towers, blades, and the cells. There's no change to the vessel's expected availability to support the current CVOW construction schedule, which we anticipate will start in the third quarter next year.

As reflected in today's materials, we've updated the project's current estimated costs, including financing costs, to $715 million, compared to $625 million last quarter. The drivers for the increased costs are modifications to accommodate project-specific turbine loads based on final certified weights and dimensions of the equipment and additional financing costs. The modifications will enable Charybdis to handle the latest technology turbine design.

Charybdis is vital not only to CVOW, but also to the growth of the offshore wind industry along the U.S. East Coast and is key to the continued development of a domestic supply chain by providing a homegrown solution for the installation of offshore wind turbines. We continue to see strong interest in use of the vessel after the CVOW commercial project is complete.

Let's turn to South Carolina on Slide 15. On July 12, we, along with the Office of Regulatory Staff and other interveners, submitted a comprehensive settlement agreement in our pending electric rate case for approval by the Public Service Commission of South Carolina. The settlement includes all parties signing on or not opposing and reflects the strong collaboration throughout the process.

The settlement is premised on a 9.94% allowed ROE and a 52.51% equity capital structure. Compared to rates at the time of our original request in March and offset by the fuel reduction and other factors, the settlement's rate request would represent a net 1% increase for residential customers' electric rate. If approved, new rates will go into effect September 1st. We look forward to further collaboration with stakeholders in South Carolina.

Moving now to data centers on Slide 16. As I've said before, we're ramping into the very substantial and growing multi-decade utility investment required to address resiliency and decarbonization public policy goals, plus the very robust demand growth we're observing in real time across our system. This growth has been recognized by third-parties. As just one example, Virginia was recently named America's top state for business in 2024. This was Virginia's record sixth time at the top of CNBC's rankings, and its third win in five years, a record unmatched by any other state since the study began in 2007.

For full-year 2024, we expect DEV sales growth to be between 4.5% to 5.5%, driven by economic growth, electrification, and accelerating data center expansion. It's worth noting that in July, we registered six new all-time peak demand records, and just as we expect, our customers likely had no idea of these demanding load conditions, given the high-quality operational performance delivered by our colleagues.

The data center industry continues to grow in Virginia. We've connected nine new data centers year-to-date through July, consistent with our expectations to connect 15 data centers in 2024. Since 2013, we've averaged around 15 data center connections per year. However, growth is accelerating in orders of magnitude, driven by the number of requests, the size of each facility, and the acceleration of each facility's ramp scheduled to reach full capacity.

We're taking the steps necessary to ensure our system remains resilient and reliable. We had accelerated plans for new 500 kV transmission lines and other infrastructure in Northern Virginia, and that remains on track. We were awarded over 150 electric transmission projects totaling $2.5 billion during the PJM open window last December. PJM's latest open window, which commenced on July 15, is anticipated to be equal to or greater in investment needs, as the RTO looks to accommodate data center growth both in Northern Virginia and beyond with additional transmission upgrades.

We're working expeditiously with PJM, the SCC, local officials, and other stakeholders to fast-track critical projects. We're committed to pursuing solutions that support our customers and the continued growth of the region. This includes assessing dispatchable generation needs, especially during winter, and on-site backup fuel storage. To that end, in June, we filed a petition with the SCC to construct and operate a backup fuel source for Brunswick and Greensville power stations to support operations and improve system reliability.

Additionally, in July, we announced the acquisition of an additional offshore wind leasehold in North Carolina from Avangrid, which we view as an attractive option for future regulated offshore wind development, as well as a request for proposals to evaluate feasibility of development of small modular reactors at our North Anna site. These projects reflect an all-of-the-above approach to meet growing demand.

When we consider this demand growth, we think about the full value chain, transmission, distribution, and generation infrastructure investment that has and will continue to drive utility rate-based growth. Given these drivers, we continue to believe there may be opportunities for incremental regulated capital investment towards the back end of our plan and beyond. As I've said before, we will look at incremental capital through the lenses of customer affordability, system reliability, balance sheet conservatism, and our low-risk profile.

Looking forward, we'll file a new IRP in October. Last year's IRP factored in significant load growth and investment in generation and transmission over the next 15 years to meet that load growth, while keeping the cumulative average annual growth in the customer bill below 3%. The most recent PJM DOM Zone load projections, as shown on Slide 17, which were only modestly different than last year's, along with our work to optimize the best ways to meet this load, will be factored into our planning for this year's IRP.

Before I summarize our remarks, let me touch on data center cost allocation on Slide 18, which has been a topic of investor interest. We routinely examine cost allocations and the corresponding rate designs to ensure they're fair and reasonable. Distribution and generation rates are reviewed by the SCC every two years, and with our next biennial review in 2025. Transmission rates on the other hand, are reviewed by the SCC every year during our Rider T1 proceeding.

In both proceedings, if the cost of serving one or more customer classes has changed over time, then costs are reallocated to ensure each customer class is paying their fair share. If the cost of serving one customer class has increased, for example, then their cost allocation will increase, and the cost allocation for all other customers will decrease.

The most important example in recent years has been the significant reallocation of transmission costs from residential customers onto larger energy users, such as data centers. Since 2020, residential customers' allocation of transmission costs has declined by 10%, while GS-4, our largest energy usage customer class, has increased by 9%. This reflects the growing share of our system that is made up of data centers, along with the shift in how we allocate transmission costs among the classes.

We've also adopted other rate mechanisms in recent years that combined with regular and routine assessment of cost allocation and rate design, ensure costs are shared equitably across rate classes. We have a long and exciting history of working with data center customers, and we look forward to supporting all of our customers going forward.

With that, let me summarize our remarks on Slide 19. Our safety performance this quarter was outstanding, but there's more work to do to drive injuries to zero. We reaffirmed all financial guidance. Our offshore wind project is on time and on budget. We continue to make the necessary investments to provide the reliable, affordable, and increasingly clean energy that powers our customers every day. And we are 100% focused on execution. We know we must deliver, and we will.

With that, we're ready to take your questions.

Questions And Answers

Operator

(Question And Answer)

And at this time, we will open the floor for questions. (Operator Instructions) We'll pause for just a moment to allow questions to queue. And it does look like we have our first question from Constantine Lednev with Guggenheim Partners.

Q - Constantine Lednev {BIO 20877967 <GO>}

Hi. Good morning, team. Thanks for taking my questions.

A - Robert M. Blue {BIO 16067114 <GO>}

Good morning.

Q - Constantine Lednev {BIO 20877967 <GO>}

Starting off on the offshore progress, there's definitely some strong progress there on the pile driving season. It looks like you've been able to hit that two monopiles per day target. Could we see you exceed the top end of the 70 to 100 target range for the year? And maybe any remaining hurdles that we should think about?

A - Diane Leopold {BIO 16365511 <GO>}

Hi. Good morning. This is Diane Leopold. Yes, we are excited that we've been able to hit the two, and the second vessel that we have will keep us in production mode for longer into this season. We're kind of right in peak season right now. As the weather starts to change a little bit, we may not be able to keep hitting two quite as often. So we feel really confident in the 70 to 100.

And just also keep in mind that during this season, we want to put in at least enough pin piles to be able to set one of the offshore substations. So we have to take that into account. So overall, I would say the team, both our own internal team and the DEME team is doing a fantastic job and that 70 to 100 is a great range. We're very confident in it.

Q - Constantine Lednev {BIO 20877967 <GO>}

Okay. Thanks for that. And you touched on this on the resource adequacy side. We obviously saw the Dominion Zone breakout significantly earlier this week. Can you speak to how your capacity plans are evolving as it relates to the forthcoming IRP? And maybe are you looking for more Chesterfield-style gas projects at this point?

A - Robert M. Blue {BIO 16067114 <GO>}

Yes. Constantine, when we think about our plans going forward, we gave our five-year capital plan at the Investor Day in March, and we'll update that annually. That's our expectation. And then we'll file our IRP in the fall. We update that annually as well, and that takes a longer-term view.

But when we think about demand growth, we saw a big jump, as the slide demonstrates, with PJM, between their '22 and '23 forecast, a little more modest, much more modest increase from '23 to '24. So as we describe in the prepared remarks, sure, there may be some opportunities towards the back end of the plan to increase CapEx, and lots of data points indicating that we need generation, which we've been saying for some time, both renewable and dispatchable in our service territory here in Virginia.

So we'll update the capital plan next year. We'll have an updated IRP based upon the PJM forecast, which was not hugely different than last year's, and we'll remain very focused on making sure that we're able to meet demand for our customers. This is a really exciting time, has been in Virginia. We're very excited to help keep the state number one for business going forward, and that'll require investment in distribution, transmission, and generation as outlined in the plans we've put forward.

Q - Constantine Lednev {BIO 20877967 <GO>}

Excellent. I really appreciate the details here. I'll be jumping back in queue. Thanks so much.

Operator

And we have our next question from Nick Campanella with Barclays.

Q - Nicholas Campanella {BIO 20250003 <GO>}

Hey, thanks for taking the time, and hope you're having a good summer.

A - Robert M. Blue {BIO 16067114 <GO>}

Thanks. Hey, Nick.

Q - Nicholas Campanella {BIO 20250003 <GO>}

Hey. So I just wanted to follow-up on the auction comments, just because I know you went through those pretty quickly. So your short generation for next year, that's a $0.04 impact. What does that look like as you get into '26? Like, do you have additional generation coming online? I'm just kind of trying to think that if things continue to be really kind of tight here for '26, '27, does that $0.04 continue? And can you just kind of expand on, like, the mechanism and what differs the VIU, vertically integrated model, versus T&Ds and why you have this kind of dynamic going on? Thank you.

A - Steven D. Ridge {BIO 20475546 <GO>}

Yes. Nick, I'll take it. So as I mentioned, we've got a natural hedge, which is the generation we own is bidding into the capacity market and receiving the elevated price, or will receive the elevated price you saw clear. So that revenue credits to customers. Simultaneously, we have an obligation as a load-serving entity to also go out and procure enough capacity to satisfy our load, and that we'll be paying that high price as well. So naturally, we have this hedge of effectively receiving revenue at the same time as we're outlaying expense.

The reason we have a small hurt in the second half of '25 related to this is because we do have a short position between the organic generation that we own and bid into the market versus the load. And we typically satisfy that through imports from PJM, and that's not news. And that short position is anywhere between 2,000 megawatts and 3,000 megawatts.

Going forward, the reason it's leakage, so to speak, is because we're in between rate cases. And we weren't able to, because of the timing of this auction in particular, we weren't able to include the expected cost in the cost of service that we filed as part of the last biennial, and we can't change rates until the end of 2025. So for six months or I guess, seven months, starts in June.

For seven months, we'll bear the cost effectively of that leakage, but then it will go into rates, and rates will be effective.

Capacity is part of base rates. It's a prudently incurred cost. It's recoverable from customers, and that's why we shared some comments on the potential impact on customers. So this is a very, very temporary. It's driven partly by the fact that we were not in a position to increase rates as part of the most recent biennial settlement. It has to do with the timing of this particular auction. And going forward, we fully expect to be able to recover 100% of this leakage in our rates from customers.

So that's why it's temporary, and that's why we kind of said, we wanted to be transparent with folks to say, hey, here's the math, here's how it works, here's what it is, but also point to that being temporary. Bigger picture, as was alluded to in the last question, this is a consistent signal of what we've been saying of the need for incremental regulated investment will help elongate our growth rate over a longer period of time as we put more and more capital to work on our system.

So that's why we've got this natural hedge. That's what's different between the vertically integrated. And to the extent that the short position persists, which it will for some period of time, we'll have offshore wind come in, we'll have the Chesterfield CTs come in. So -- but demand is growing. So, as that persists, we'll think about ways to become effectively self-sufficient as we have been in the past, as we catch up on demand. But from a financial impact, it truly is just a temporary item.

Q - Nicholas Campanella {BIO 20250003 <GO>}

Okay. That's super helpful. I really appreciate it. Thanks for that color. On the Charybdis ship, you're 90% complete or 89% complete. Costs are up $90 million. Can you just quickly speak to what's driving that? And why this is really should be the last revision there? Thank you.

A - Diane Leopold {BIO 16365511 <GO>}

Sure. Good morning. Diane again. So, as Bob talked about, these modifications, it really wasn't any change to the base ship. Those costs did not increase. But these types of modifications just aren't unusual -- are not unusual. We had to order this ship long before the final turbine design was complete for our project. So, based on the final loadings, there's some additional deck stiffening and hull reinforcement for the towers and to support the cantilevered blade racks.

So, that's really what's driving it. It's not any kind of scope change in the ship. It's just some of these normal modifications. So, we're doing a lot of those. That work is already starting. And a lot of it will happen, while we're completing kind of the internals of the ship, finishing the piping, the electrical work, the crane loading, we'll go for sea trials and then we'll bring it back and finish the last of that work to make sure that we can get the sea fasteners on to support our specific towers, blades, and vessels.

A - Steven D. Ridge {BIO 20475546 <GO>}

And Nick, I'd just add that, of that increase, about $55 million of its pure CapEx. The rest of it is associated financing costs. And the way we finance this vessel is through a lease arrangement with a consortium of banks. And we're working with them and they've been great partners along this way. And we don't expect there to be any other increases. I'll say that. We're very confident in that. And by working with this consortium, we've been able to ameliorate the potential cost increase from a financing cost perspective. So, we view this as being less than $0.01 in terms, I think it's about $0.005 in terms of 2025 costs as a result of this increase. So, it's not a big financial thing, but again, wanted to be transparent.

Q - Nicholas Campanella {BIO 20250003 <GO>}

Really helpful. Thanks for all the answers. Have a good day.

A - Steven D. Ridge {BIO 20475546 <GO>}

Thanks, Nick.

Operator

And our next question comes from Jeremy Tonet with J.P. Morgan.

Q - Jeremy Tonet {BIO 15946844 <GO>}

Hi, good morning.

A - Steven D. Ridge {BIO 20475546 <GO>}

Good morning, Jeremy.

A - Robert M. Blue {BIO 16067114 <GO>}

Good morning, Jeremy.

Q - Jeremy Tonet {BIO 15946844 <GO>}

Just wanted to pivot conversation, if I could, towards Millstone and possibility for data center co-location there, if you could just provide any incremental thoughts on the outlook there and I guess, maybe navigating stakeholder sensitivity.

A - Robert M. Blue {BIO 16067114 <GO>}

Sure. As we've discussed before, Jeremy, Millstone is just a great asset for us. For New England, it provides 90% plus of Connecticut's carbon-free electricity. And as you know, 55% of its output is under a fixed-price contract through late 2029. The remaining output significantly de-risked by our hedging program.

So, we're actively working with multiple parties to find the best value for Millstone beyond that current PPA. We're certainly open to some longer type of PPA. There's been, over the last year, some legislative activity up in New England aimed at authorizing future further procurements. We'll have to see where all of that lands.

We're certainly open to the idea of a co-located data center. We continue to explore that option. We do clearly realize any co-location option is going to have to make sense for us, our potential counterparty, and stakeholders in Connecticut. So, not any new news there. We continue to look for options for Millstone, but it remains a tremendous asset for us.

Q - Jeremy Tonet {BIO 15946844 <GO>}

Got it. Makes sense. And just wanted to dive in a little bit more, if you couldn't kind of touch on other angles here. But as far as the ISA protest in front of FERC, where we might hear some news tomorrow, just wondering any thoughts on the subject that you might be willing to share.

A - Robert M. Blue {BIO 16067114 <GO>}

We're not a party to that proceeding, Jeremy. So, my thoughts would not be appropriately educated. So, we'll let FERC and others decide that.

Q - Jeremy Tonet {BIO 15946844 <GO>}

Fair enough. And I think you mentioned that net capacity expenses were previously only about 1% of customer bills. And just any thoughts on the range of what that could look like now after this auction?

A - Steven D. Ridge {BIO 20475546 <GO>}

It's still going to be very small, Jeremy. And we try not to think about customer bill impacts as an -- driven by isolated drivers. We try and think about all the different parts and pieces that go into that. So, I mentioned in my prepared remarks that we've seen the elimination of the RGGI Rider. That was $3 or $4 a month. So, when we come back to the Commission in March with a holistic approach, we're very, very focused on making sure customer bills are a high priority for us in making the best possible offer to our customers. So, can't give you any specific information about this, but it's not going to be a big number.

Q - Jeremy Tonet {BIO 15946844 <GO>}

Got it. That's helpful. I'll leave it there. Thanks.

A - Steven D. Ridge {BIO 20475546 <GO>}

Thank you.

Operator

And we have reached our allotted time for our question-and-answer session. This does conclude this morning's conference call. You may disconnect your lines, and enjoy your day.

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