NOVA SCOTIA ENERGY BOARD

IN THE MATTER OF: ***THE PUBLIC UTILITIES ACT***

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IN THE MATTER OF: **OF A GENERAL RATE APPLICATION BY NOVA SCOTIA POWER INCORPORATED (NS Power)** for approval of approximately $284 million of its **ANNUAL CAPITAL EXPENDITURE (ACE) PLAN** for 2026 which totals $702.1 million

TRANSCRIPT

HEARD BEFORE: Mr. Richard J. Melanson, LL.B., Panel Chair
Mr. Steven M. Murphy, MBA, P.Eng., Member
Ms. Jennifer L. Nicholson, CPA, C.A., Member

PLACE HEARD: Offices of the Nova Scotia Energy Board
1601 Lower Water Street, 3rd Floor
Halifax, Nova Scotia

DATE HEARD: Wednesday, April 22, 2026

APPEARANCES:

APPLICANT: **Nova Scotia Power Inc. (NSP)**
Ms. Jennifer Power, Counsel
Ms. Kathleen Murray, Counsel

INTERVENORS: **Consumer Advocate**
Mr. David J. Roberts, Counsel
Mr. Michael Murphy, Counsel

Small Business Advocate
Ms. Rebekah L. Powell, Counsel

Industrial Group
Ms. Brianne Rudderham, Counsel
Ms. Kaitlyn Clarke, Counsel

Port Hawkesbury Paper LP
Ms. Melanie Gillis, Counsel

Nova Scotia Independent Energy System Operator (IESO Nova Scotia)
Mr. David A. Luther, General Counsel
Mr. Mark Peachey, Director of Regulatory

Nova Scotia Department of Energy
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Mr. Girish Patel, Engineer

Eastward Energy Inc. (not present)
Ms. Allison Coffin, Director, Regulatory and Government Relations
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JOHN WILSON, Solemnly Affirmed:

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Halifax, Nova Scotia

--- Upon commencing on Wednesday, April 22, 2026 at 9:00 a.m.

THE CHAIR: Good morning, everyone. Welcome back.

We're going to start the proceeding today with questions from the Board Panel. We'll start with Mr. Murphy, but before we start, just a reminder to the panel that you're still under oath.

Also, you will notice we've got one person attending from home today, and they're -- you can see her on camera.

So with that, we'll start with Mr. Murphy.

DAVID ARTHUR PICKLES, Resumed:

TREVOR ARCHIE BEATON, Resumed:

LYNNE ANNE DROVER, Resumed:

JONATHAN ROSS CLARK MacINTOSH, Resumed:

CHARLENE DEEANNE (Sp?) MacMULLIN, Resumed:

ERIN CHRISTINE PEACHEY, Resumed:

MEMBER MURPHY: Thank you, Mr. Chair.

QUESTIONS FROM MEMBER MURPHY

Q. Good morning, panel. I've just got a couple of -- actually, I have a lot of questions, but I have a couple of what I call the short snappers, my Reach for the Top short snappers, so whoever wants to answer these, feel free.

In response to Board IR-3(e) -- I won't get Rob to call this up; I'll just read it. Nova Scotia Power said:

> Energy storage is included in the transmission function for the purposes of capital tracking. However, from a cost-of-service perspective, these assets have been proposed to be refunctionalized to

generation.

And I guess my question is, really, why -- for the purposes of capital tracking, why aren't energy storage assets functionalized -- or classified to generation?

A. (Pickles) Yes, good morning.

The move to power production really is just to align how, operationally, we're going to manage the site, so there's really good alignment with how we're currently structured with our wind farms. We manage long-term service agreements on the wind properties that are either owned or operated on our -- in the province, so similarly, the battery sites are under a long-term service agreement as well, so they will be managed within the power generation group per se.

Q. So the intent -- so they'll still be, for capital purposes, tracking -- I guess they'll be, I guess, functionalized to transmission. You don't intend on moving the generation.

A. (Pickles) That's correct.

Q. Okay. Thank you.

MEMBER MURPHY: Another quick one, Rob, if I could get you to call up Exhibit N-1, PDF page 15.

BY MEMBER MURPHY:

Q. That graph there, Figure 2, shows total annual capital expenditures by function. And just a real quick question here. In response to Board IR-3(f), Nova Scotia Power provided a spreadsheet with this table.

And I can get Rob to call it up for you if you want, but for 2024 the spreadsheet showed a total of 487.2 million. All the other years in the spreadsheet were -- matched this particular figure, but 2024 appeared to be off.

So I'm curious which is the right number, really.

A. (Beaton) Could you bring up the IR?

Q. Sure. It's the spreadsheet for the IR.

A. (Beaton) Okay.

Q. There's an attachment.

MEMBER MURPHY: Rob, maybe you can bring it up. It's Exhibit 6(i).

(SHORT PAUSE)

BY MEMBER MURPHY:

Q. There you go.

So you can see 2024, it's 487.2. And like I said, all the other years appear to match Figure 2, so it suggests that maybe one of those has an error in it.

A. (Beaton) Correct, yeah. I would want to take it away as an undertaking just to confirm which is which -- which is the proper one.

Q. Okay.

THE CHAIR: Okay. So Undertaking U-17 would be to confirm whether the table in -- or -- yeah, the table, I'll call it, in IR-3, that's N-6(i), is the correct one or whether it's the one from the -- from page 15 -- PDF page 15, Figure 2 of N-1.

UNDERTAKING U-17 - To confirm which table is correct from IR-3

MEMBER MURPHY: Thank you.

And my last sort of short snapper here is, Rob, if you could call up N-1, PDF page 138.

BY MEMBER MURPHY:

Q. And this is -- this shows all the depreciation rates that were included within the ACE Plan. It shows the 2026 depreciation rates in the ACE Plan.

And to me, these appear to be a little bit different than the depreciation rates that were included in the GRA in the Settlement Agreement.

I can call those up if you want, but they are different. So I guess my first question is, the fact that they're different, does it have any impact on the ACE Plan except for changing this particular figure?

A. (Beaton) It would have no impact, no. It would have included the approved depreciation rates at the time of the ACE filing, but upon the invocation of the GRA in April it switched to the new rates. So it would have no impact on the actual ACE Plan for any of the numbers included.

Q. Okay, perfect.

Mr. Chair, maybe just for the record because -- I think the GRA depreciation rates will, in fact, be the 2026 depreciation rates; correct?

A. (Beaton) Yeah, we will implement those rates in the initial months after final approval.

Q. So maybe, for the record, if -- you know, for the purposes of next year's ACE Plan, if folks are comparing plans, maybe for the record we should get the updated ---

THE CHAIR: The only thing is that it will only be -- I mean, formally finally updated when the final Order is issued, which will depend on when -- I'm not involved in the GRA, but I know there's been a back and forth with respect to certain issues, so the question is timing.

MEMBER MURPHY: Okay. I don’t think the depreciation rates are going to change.

THE CHAIR: No, no, no. It’s not that the depreciation rates are going to change, so...

MEMBER MURPHY: I’m fine. Let’s leave it.

THE CHAIR: I mean ---

MEMBER MURPHY: We have long memories. We’ll remember.

MR. BEATON: It is important to note that these depreciation rates will be utilized, and have been utilized, for the first few months of the year as well.

MEMBER MURPHY: Right, yeah.

THE CHAIR: Until the actual order is issued.

MEMBER MURPHY: Okay. Thank you.

BY MEMBER MURPHY:

Q. Okay. I'll move on to -- I have some specific questions on some of the projects that have been submitted for approval.

And I think my first set of questions -- Ms. Drover, you might have thought you got off easy yesterday, but maybe not today.

So I think these first questions might be for you, but if not, I'll leave it to the panel to decide.

So my first questions are related to the Tufts Cove Shoreline Refurbishment Project. So would those be for you, Ms. Drover?

A. (Drover) Yes, they would.

Q. Okay. Thank you.

MEMBER MURPHY: Rob, can you call up Exhibit N-1, PDF page 155, please?

BY MEMBER MURPHY:

Q. And this is just -- this is a

minor question, but I was curious why the design of bathymetry and surveying number was redacted.

A. (Beaton) Mr. Murphy, that number is simply redacted so as the two totals for the materials and contract number can't be figured out. So we are required to redact one other number in the filing so as nobody can calculate the end costs for the materials and contracts.

Q. Okay.

A. (Beaton) So when we have a total that we need to keep redacted, we ---

Q. Understood.

A. (Beaton) --- are forced to redact one other number ---

Q. Okay.

A. (Beaton) --- just to -- and it would have just been chosen almost at ---

Q. Sure. That's fine. Thank you.

MEMBER MURPHY: Rob, maybe you could

go to PDF page 166, then.

And Ms. Drover, in this -- this is Board IR-69 -- I may have the wrong page there, Rob. It's Board IR-69(a).

Sorry; it's in Exhibit N-6, Rob. PDF page 166.

BY MEMBER MURPHY:

[9:10:03] **Q.** So in that Board IR-69(a)(i), the Board asked Nova Scotia Power to provide an EAM and a Net Present Value analysis for the three options that were presented in the -- I'll call it the Options Analysis Report. The three options are, I think, a combi-wall, retaining wall, and the selected option in which was a rock revetment option.

So in the IR, the Board asked for the EAM which would outline capital costs for all those options and the operating costs, a typical EAM that Nova Scotia Power would provide for any capital project.

MEMBER MURPHY: In response -- if you want to scroll down to the next page, Rob.

BY MEMBER MURPHY:

Q. Nova Scotia Power said neither a cost/benefit analysis nor an EAM was required for the project. Instead, an options analysis was completed by a third party, the third party being a consultant. And it was attached to a capital work order in the Application as Attachment 1. And the IR response goes on to say:

> The options analysis indicated that there were two alternatives that met the design criteria...Of those two options, the [rock] revetment option was considerably more cost-effective and did not have any higher future costs that would require an EAM or NPV analysis.

MEMBER MURPHY: So Rob, you can go back to N-1, PDF page 175.

BY MEMBER MURPHY:

Q. Ms. Drover, I have a few questions on that options analysis and the way each option was scored.

So here's the scoring criteria for

each one of those options. The three criteria were -- sorry, four criteria -- were meet design criteria, weighted 40 percent; impact on existing operations, weighted at 25 percent; environmental permitting considerations at 15 percent, and probable cost weighted at 20 percent.

I guess my first question was, how was it decided that those were the four, I guess, best criteria in which to rank each one of those options? The second part of that question is, how was it decided that each of those particular weights would be assigned to those criteria; and, in particular, why was cost assigned, you know, the second load?

A. (Drover) Thank you, Mr. Murphy.

So to develop the weightings for the four different criteria, that was done through conversations with internal subject matter experts, as well as consultants. And first and foremost, the option needed to meet the technical or design criteria in order to meet the requirements for the project, but also it was very important that we gave a significant weighting to the cost of the project.

Q. But the weighting for cost was the second lowest.

A. (Drover) That is correct. So making sure that the option met the design criteria was the most important. And one of the options did not meet the design criteria, as I'm sure you've read in that document, because it did not meet the structural integrity that was required. So starting at that point, making sure that we were meeting the design criteria, and then moving forward and looking at the cost.

Q. I know you just reiterated what the IR suggested, that two of the options met the design criteria, and I understand what you're saying about you're saying about the retaining wall, but the scoring methodology, it says option -- a score of one indicates that the option "Vaguely meets the design criteria," so

I’m not sure how that translates into not meeting the design criteria, and there were certainly some recommendations in the study that -- or this analysis -- there's a recommendation for potential further study of that retaining wall option to perhaps confirm that that option would, in fact, entirely meet the design criteria.

So can you just explain to me how you translate “Vaguely meets the design criteria” with the potential to do a little bit more work to assess whether in fact it does meet the criteria, how that translates into it doesn't meet the design criteria?

A. (Drover) At the current evaluation, it did not meet the design criteria, as noted -- or as you just noted. With a little more work, potentially, could provide some stability. However, just reviewing that option, I think, might be helpful. Maybe not everybody is as familiar as we are.

So the stability of the current shoreline sheet pile is quite deteriorated and does not provide the required stability that's needed, so that retaining wall option was to add a layer or encapsulate that current retaining wall in concrete, and then on top of it build an additional retaining wall structure.

So there continued to be concerns because even the encapsulation of the retaining wall meeting the necessary and longevity of what was required for the stability of the shoreline remained a concern for both our internal subject matter experts, as well as our consultants. So that option, with our lack of confidence that it would provide that long-term stability that was needed for decades, was eliminated as an option at the preliminary stage.

Q. But wasn't the recommendation to do further study? Would that have not have, I guess, reconfirmed your confidence that that particular option would or would not have met the design criteria?

A. (Drover) Further study would absolutely provide more information. I would say that we weren't confident that further study would necessarily provide us the assurances that we would need in order to place that option as a viable option.

In addition, that option was priced very similarly to the rock revetment option. So having an option that met the design criteria that was a similar price in the preliminary costing, and not going forward spending the additional funding that would require to do the additional study work, it was decided to proceed with the rock revetment option.

Q. Okay. I have some more questions about the costing, but the costing that's been presented now, based on the tender price, is a lot more than the costing for that particular option that was presented in the Options Analysis Report.

A. (Drover) That is correct.

Q. I'm just curious. If an option doesn't meet design criteria, why would it even be presented as an option?

A. (Drover) Well, I think it's fair to say that at the time when the different options were identified, it was potentially considered to be an option that may be feasible. And through the preliminary analysis was found that it wasn't feasible. So for completeness it was an option that was initially evaluated in the preliminary engineering work, so it was shown and presented in the report.

[9:20:04] **Q.** Okay. I kind of got sidetracked, but I'll get back to my questions about the analysis and the scoring. With the weighting and the way it was scored, you know, a score of 1 -- let me just if I -- if I pick design criteria I have a weighting of 40 percent if you got a score of 1 you were given 40 points, if you got a score of 2 you're given 80 points, if you got a score of 3 you're given 120 points. Is that correct?

A. (Drover) I would have to refamiliarize myself with the scoring, ---

Q. Well, just look at -- if you just look ---

A. (Drover) --- but subject to check.

Q. If you just look at Table 3 that's for the combi-wall, you see it got a score of three, the weighting's 40 percent, which gives it a weighted score of 120. Do you see that?

A. (Drover) Yes, I do.

Q. Okay. So my question really is why not if you're using the weighted system, a scoring system like that, why not just -- you know, the -- why not just give it a score out of 40 instead of putting the weight on it? If you give it a score of 40 and let's say hypothetically you thought one particular option, you know, met half the design criteria, if you want to call it that, it would get a score of 20, so a spread of 20 points between that option and the preferred option. In this particular case you're getting a spread of 80 between the least preferred option and the preferred option. And in fact you could -- and you could argue, well, you know, the means of scoring are one, two, three, that's a bit arbitrary. You get one, two, three, four, five and -- so why not -- why not just give it a score of 40?

A. (Drover) I think the methodology that you suggested is absolutely an option to do in either way. Whether you take the scoring and use it as a divisor or a multiplier on the weighting, mathematically we would end up with the same order of the rankings in the end. I appreciate your point that the spread would be bigger because the overall totals would be larger by doing a multiplication method versus a division method in the weighting. However, it would not change the resulting order of the options in the end.

Q. Assuming the -- that's assuming the -- you know, the preferences for -- that would be assuming -- if I use this example of the score of 40 that if you just used 40 as your scoring point that would assume the least option would get a third of those -- in order to be comparable at this particular scoring your least favourable option would get a third ---

A. (Drover) Of 40.

Q. --- of 40.

A. (Drover) Yes.

Q. Which -- I don't know -- it may -- it could happen, I suppose, in reality, but I'm not sure if it would or not. I understand your point.

A. (Drover) I thank my colleagues for their contribution that -- I also would like to acknowledge that this is the CBCL report and their recommended weighting, and also acknowledge that CBCL are subject matter experts or experts in this field, and this was the methodology that they recommended.

Q. I understand that, but it still can be -- it still can be critiqued by the Board certainly.

A. (Drover) Absolutely.

Q. And this was the methodology that was used to select the preferred option.

A. (Drover) Yes.

Q. In terms of the weighting for the cost, again it was weighted 20 percent and ---

MEMBER MURPHY: Scroll down a little bit, Jeff -- or Rob, to the next page.

BY MEMBER MURPHY:

Q. Option 2 was given a score of 2; that's the retaining wall option. And Option 3 was given a score of 60; that was the preferred option.

MEMBER MURPHY: When you go to I think it's -- if you scroll up a few pages, Rob. Keep going. Right there.

BY MEMBER MURPHY:

Q. If you look at the cost -- right there. If you look at the costing percentage-wise -- I guess my question is really why wasn't the cost scoring related to these options done on a pro-rated basis rather than the way it was presented by CBCL? If it was done on a pro-rated basis, you know, the score for the retaining wall option would have been about 15 percent lower than the score for the rock revetment option. Instead it was about 33 percent, or there was a spread of 20 points between the rock revetment option and the retaining wall on cost, whereas if it was done on a pro-rated basis based on the actual cost the spread would have only -- I don't know if it would have made a difference in terms of the -- you know, the preferred option, but the spread would have only been three.

A. (Drover) Thank you. I am following what you're saying. Again, I will go back to this was the recommended approach from CBCL, and in the end it would not have changed the decision. The rock revetment option met the design criteria. The retaining wall option was eliminated because of concerns with meeting the design criteria of providing the necessary structural stability.

So if that had have been a weighted

option or the option recommended by CBCL it would have ended up in the same decision.

Q. Okay. Thank you.

I don't think there's any need to call this up, Jeff, but in the contingency statement for the project it talked about the contingency covers additional feedback that might be received from the Department of Fisheries and Transport Canada and whatnot, and then in response to Board IR-72, Nova Scotia Power notes that the project based -- I guess based upon feedback from both those organizations indicates the *Fisheries Act* authorization is going to be required for that particular project and is planned to be submitted for approval in February of 2026. My question is, what's the status of that FFA Application?

A. (Drover) That *Fisheries Act* authorization was submitted in the month of March. So that has been submitted.

Q. And I know there's been a history with other Nova Scotia Power projects that required a *Fisheries Act* authorization with delays associated with actually obtaining that approval. And in one particular case I can recall the delay was quite significant. Do you expect any delays associated with this approval?

A. (Drover) We do not in this case. The submission in this case is very different than the submissions associated, for example, with our hydro projects, and we have had active engagement with DFO, NSE, as well as Transport Canada throughout the preliminary stages of this project. So we are not, at this time, expecting delays.

Q. Okay. And notwithstanding what you noted earlier about Option 2, the retaining wall option, and that it was kind of just discarded; I have some more questions about that, but would Option 2 have required at FAA? My understanding about Option 2 is that -- at least in the material I looked at is it didn't require an extension to the cooling water intake line whereas the other two did. So in that respect would that option have required an FAA?

A. (Drover) I would have to take that away. And I agree with your thoughts about the work product being on the shoreline; however, there may be construction activities that would impact the water. And if those construction activities in any involved disturbances within the water, a *Fisheries Act* authorization would be required.

So I do not have the -- that information with me on hand. I would have to take that away to look. But I can say confidently that I would imagine that doing this work so close to the shoreline would involve interaction with the water and, in doing so, would require a *Fisheries Act* authorization.

[9:30:32] **Q.** Okay. Thank you.

I don't need the -- I don't need an undertaking on that. I hear what you're saying.

In terms of the contingency amount

that's included in the project cost amount right now, does that incorporate a contingency for the feedback that you have received from Department of Fisheries and Department of -- Transport Canada?

A. (Drover) Yes, it does.

Q. The project, when it was considered in the options analysis, there was no discussion about work scheduling and whatnot. Now, I understand that the project is scheduled to occur at the same time as the planned outage for Tufts Cove 3. Is that correct?

A. (Drover) That is correct.

Q. Okay. Is there any provisions in the -- I don't know if you have a contract yet for that particular contract or maybe in the tender documents, is there any provisions in that -- in those documents for liquidated damages or penalties if the project's not completed by the November 24th end of the planned outage?

A. (Drover) The work that would have the most significant impact on Tufts Cove 3 would be the extension of the cooling water intake, which would be work that would happen at the beginning of this project.

As part of the responses to the Board IRs, we did include the responses to the requests for proposals. I do not have the information with me today to speak to whether the resulting contracts incorporate liquidated damages. I can take that away and provide that information back if you'd like.

However, what I would say is that work is happening early in the outage and that throughout scheduling and the timing of that work with the associated outage, there would be a lot of mitigation to make sure that the work that would impact the duration of the outage was done early and on time to not impact the return to service of Tufts Cove 3.

Q. Are the dates for the outage fixed? Are those fixed at October -- I think it's October 2nd for start? Because I suppose there could be potential, I don't know, for delay in this particular project. So if the outage was to start on October 2nd and this project didn't start on October 2nd and perhaps got delayed a little bit, then that could present concern.

A. (Drover) So we have a thermal maintenance schedule where we work together, and units are scheduled to take their turn to take an annual outage. So we try the best we can to stick to that schedule. However, if there are significant changes in our fleet, whether that's due to a capital project or due to another item, that schedule is not fixed and there is always the ability to look at a fleet-wide basis and make adjustments to that schedule; for example, have another unit start their annual outage and then do the annual outage for Tufts Cove 3 afterwards, or shift schedules by a matter of weeks.

Q. So if this project were to be -- if this particular shoreline refurbish or restabilization project was to be -- if it got delayed for some reason, would the intent be to delay the start of the outage?

I guess my concern would be, you know, if there's any issues with this particular project that extend that outage beyond the -- you know, the proposed window and that perhaps there could be additional costs imposed upon ratepayers associated with dispatch costs and things like that. And if there's no provisions in the contract for liquidated damages -- I know sometimes those are a bit hard to enforce, but regardless, if there's a clause in there for liquidated damages, customers would be somewhat protected from those additional costs. If there's no clause for liquidated damages or penalties in there and the outage extends longer than was first proposed because of a delay associated with this particular project, then there'd be additional costs on ratepayers.

A. (Drover) Yeah, I appreciate that concern. And what I would say with regards to that is it would be important for the outage and the project to align. And if there were changes to the timeline of the project, that we would take that under advisement and look at what we can do to get that project back on track or what we're going to do to adjust the thermal maintenance schedule.

These type of activities aren't unusual for us in the power plants, so no matter what large capital project we are doing, we can experience changes in shipping times for materials or material availability, and we very regularly manage those types of risks to mitigate factors that would cause delays, and also make sure that we maintain an appropriate level of flexibility in case there are unforeseen changes.

So I just wanted to take the opportunity to talk about that this is not something that is unusual for us to manage and we do it very successfully on a regular basis. So sitting here, I don't have concern in our ability to manage that and to manage the timeline of the project.

Q. Okay. Thank you.

MEMBER MURPHY: Rob, are you in N-1? Is that N-1?

Can you go to page -- PDF page 165?

BY MEMBER MURPHY:

Q. And this is from the Options Analysis Report. And right there, it's the Section 3. It's the second paragraph. I'm going to read it. It says:

> It is important to note that the information on the site, such as existing geotechnical conditions, seabed bathymetry, and environmental conditions, is extremely limited. The options presented are based on assumptions that will have to be validated during detailed design. Within the OPC for each option, probable costs are given for the appropriate investigations to determine this critical information and confirm final configurations.

In response to Board IR-74, Nova Scotia Power indicated that, I think, it had completed all of this work for the preferred option, or for the rock revetment option. And it further noted, it said:

In general, the bathymetry scanning and the boreholes influenced the overall design of the geometry of the rock revetment [option].

[9:40:06] The Options Analysis Report also recommended a coastal study be completed to confirm the detailed design of the options. And again, Nova Scotia Power confirmed that that coastal study was done.

My question really is, I'd like to know why, you know, the suggestion in this report is the bathymetry, or -- you know, I had a colleague that used to call it "bathmetry," but anyway, it's bathymetry. Provided the bathymetry, the geotech work, and the environmental studies, coastal studies, and whatnot, were not completed as part of the predesign, because certainly the suggestion in this report is that for the combi-wall option, it costs, based on obtaining the bathymetry information and the geotechnical information that the cost for the combi-wall option could certainly come down quite a bit. They said there's very conservative options in the cost for that particular option. And I suppose, again, notwithstanding what you said about Option 2, which was the retaining wall, I suppose that information could have been used to perhaps confirm the cost for that particular option.

So really, I guess I'm curious why -- you went ahead and did the work associated with Option 3. I'm curious why it wasn't done in advance to obtain all that information so it could be assessed against all the other options to confirm the cost estimates from the options analysis. And I'm going to put that in the context as well that the preferred option now is quite a bit more, in terms of costs, compared to what was included in this particular. It's almost double; it might even be a little bit more than double.

A. (Drover) Yeah, thank you for that question.

So the information that we have received through the subsequent work is very good information. That information did lead to increased cost for the rock revetment option. However, the information would also lead to increased cost for the combi-wall option as well. And all of that information we received through those studies would not have impacted the choice. So the encapsulation retaining wall option still would be removed because it did not meet the structural requirements and the combi-wall option would also increase in cost due to the information that was received on the condition of the seabed floor. So neither option would have become the preferred option. So I just wanted to start there.

At the point in time of the options analysis, the idea is to start and take the information that we had -- and we did have quite a bit of information at the time -- and look at the different options.

So, for example, if the option for the encapsulation and retaining wall option had have provided the structural stability that provided confidence that that was an appropriate option, that could have -- or other options that would involve only work on the shoreline and not into the water, would have potentially changed the need to proceed with the expense of doing the extensive bathymetry and geotechnical work that was done. However, through the preliminary options analysis, when options were identified and evaluated on a preliminary basis, it was determined that the most likely option, and the option that would meet the design criteria, would involve being on the seabed, making the bathymetry and geotechnical work necessary to be done.

So taking that first preliminary view, looking at all of the options, and understanding that before making the decision to move ahead and spend the cost to do that detailed study work, I think would be an appropriate way to try to minimize additional costs, but based on that preliminary options analysis, it was then necessary to continue on and do that work on the seafloor and understand the conditions.

Q. But this bathymetry work and

geotechnical work that was completed for -- to assess the preferred option, that work would have been the same, would it not, regardless of the options? If you had done it at the predesign stage, the work you would have done at predesign to assess all three options, that would have been the same type of work you would have done to assess Option 3; would it not? So the cost wouldn't have been any different.

A. (Drover) At the time when we were identifying preliminary options, it was uncertain of the requirement or the options that were going to necessarily involve all of the work that was done on the study work subsequently. Would some of that geotechnical or bathymetry work be done in any case? Possibly, or even probably. But understanding what options were possible or probable early on led to the development of a more detailed and exact scope of what we would want to do and investigate in that post-study work.

Q. For the preferred option?

A. (Drover) For the preferred option.

Q. Based on the options analysis.

A. (Drover) Yes.

Q. How do you know -- I think you said a little bit earlier that with the information that was collected, that the cost for the combi-wall option would have gone up. How do you know that? The report certainly suggests that the cost estimates for that option were conservative in this particular report, and had potential to go down, based on that information.

A. (Drover) So some of the drivers that led to the cost increase, the geotechnical investigation identified the need for dredging and additional foundation preparation to support the intake extension and also that there was a redesign of the Unit 3 intake extension. And those items would also be cost drivers in the combi-wall option.

Q. They wouldn’t be cost drivers for

Option 2 though, right? Notwithstanding what you said about the viability of Option 2, and notwithstanding that the recommended work from this option's analysis wasn't done to see whether that particular option was in fact feasible, the information you just referenced wouldn't apply to Option 2; there was no intake extension?

A. (Drover) There was no intake extension to Option 2, that is correct. But I will go back to Option 2 did not provide the structural integrity that was required for this project, so it was eliminated.

Q. I understand that, but I don't -- correct me if I'm wrong, that was not confirmed through the further study that was recommended in this particular report?

A. (Drover) I'm sorry; would you mind repeating the question?

Q. Not sure I asked a question. I might have just been giving a comment.

A. (Drover) So I guess I will --

maybe it will be helpful to sum it up.

We had three options. We did the preliminary design that identified three options, then subsequently, through that preliminary evaluation, one of those options was eliminated due to structural integrity.

[9:50:05] **Q.** I'm just going to interrupt you, if you don't mind.

The report -- this report, the way I read it, it didn't eliminate that option. It suggested further study to confirm the viability of that option. And then when you look at the costs that have come in, you referenced further dredging would be required for Option 1 and 3, the cooling -- and we know the cost -- we know the cost difference for the redesign of the cooling water intake; that's identified in the response to the IR. There's a pretty significant difference between the number that was estimated for that extension in this particular report versus the tendered cost.

And the other issue is the -- this

particular report, the Options Analysis Report, didn't look at any work scheduling. And perhaps -- I don't know -- perhaps Option 2, again notwithstanding your contention about its viability, perhaps wouldn't have required being done during an outage if it didn't require cooling water intake extension.

And it's noted in the IR responses that the work required to complete Option 2 during that outage is one of the drivers for the significant cost increase. Extra labour -- I forget what the -- we could call up the IR, but it references a bunch of additional costs related to having to work within that window for the outage, and perhaps that wouldn't have been required for Option 2.

What it boils down to me is, you know, there was a lot of information available -- or there could have been a lot of information available to reassess the options at the pre-design stage, but even more so after the tender closed and the cost is significantly higher than what was presented in this particular report, that all the information that was collected related to the coastal study, the bathymetry, the geotechnical information could have been used to go back and re-evaluate the options to see whether, in fact, the rock revetment option remained the lowest cost. Do you not agree?

No, go ahead. Go ahead.

A. (Drover) I appreciate the -- what you're taking from the report. And one of the items that myself and internally we have the benefit of are the conversations with subject matter experts both at CBCL and internally regarding the feasibility of Option 2, and those subject matter experts do not see that as a feasible option.

And I appreciate getting or retaining CBCL to write a report evaluating the options. Where that option has not been extensively investigated and looked into, that CBCL would not include in that report a complete elimination of that option without doing additional work.

However, I will loop back to the feasibility of that option, based on both internal and external subject matter experts, is that it would not provide that structural stability.

Throughout the evaluation of the report, there is a lot of information regarding the degradation of that existing sheet pile -- shoreline sheet pile. It is in advanced stages of degradation and the work to be done to support that with concrete and then build a retaining wall on top of it and leveraging that degraded structure and ensuring that we have stability afterwards is very concerning. So that option was confidently eliminated.

I would agree that there is more work that could obviously and always be done to study and understand what we would need to do in order to make that option have the stability that would be necessary, which would probably lead to increases in the costs associated with that project. Due to the concerns by all subject matter experts, that option was eliminated.

And then going back to the combi-wall, the drivers that increase the rock revetment project would also increase the combi-wall, but that isn't the only concern with the combi-wall.

The combi-wall is a complex project that involves drilling in the seabed, extensive interaction with the seabed and the sea floor. It is a complex installation that would be much more extensive and much more complex in order to execute, and that would also be very challenging to do in the outage window of Tufts Cove 3.

So those items, besides the fact that it was a higher-cost project, led to the elimination of that option.

So I am very confident that the team picked the right option, based on meeting that design criteria, it being the lowest cost and it being a simple design that can be executed in the window that it needs to be executed in, having the minimal impact on Tufts 3 returning to service.

Q. Okay. I appreciate that answer.

I guess my concern -- I don't know if it's the other Panel Members' concern -- is that, you know, the option that was selected was based on this report. That's what's been filed. And the tendered cost for that preferred option is now outside of the accuracy range of the estimate that was presented in this report.

The accuracy range of the estimate that was presented in this report was like minus 50 to plus 100 percent. The tendered cost is over that now, and Nova Scotia Power relied on that particular estimate as one of the factors it used to select that option. And now the cost is significantly higher.

So my concern -- I'm just expressing a concern, is that, you know, you had some new information or some information you collected, geotechnical information or bathymetry or whatnot afterwards, and that it doesn't appear to me to be anything on the record right now that says, okay, whoa, the cost has come in quite a bit higher. Let's just go back and take a look at these options, these other options, with the new information we have, to make sure that this is still, from the cost perspective, still a preferred option, particularly when the cost of the project now is outside the typically expected accuracy range of the estimate that's presented in this report.

[10:00:21] I wasn't really asking a question. if you want to comment on what I just said, that's fine, but I wasn't really asking a question.

A. (Drover) No, I appreciate that. And what I will assure you and the Board is that when those costs did come in, that the team did, again, as always, revisit that there would be similar cost pressures on the combi-wall and that the other option would still be eliminated, making this option the preferred option. Do we see that in a report? No. Our team always takes the information that we receive and ensures that we have the right information. And I think, you know, making sure that we do that detailed design and detailed evaluation in order to get a better understanding of what the costs of the project are is very important, and doing that work prior to filing the project is also very important to make sure that when we're doing projects that we have the best information on hand in order to stay within budget on these projects.

So in the end, the decision would not change, as I've discussed.

Q. Okay. I appreciate that. Thank you. The Chair is probably going to get mad at me because I beat this one for an hour now and I'm a tenth of the way through my questions.

THE CHAIR: I never get mad at questions from Mr. Murphy.

BY MEMBER MURPHY:

Q. I'm going to move on from this one, but just one real quick question, and it's related to the -- maybe this is a question for you, Mr. Beaton. It's related to the proposed change in scope definition.

If this project changed from the rock revetment option to one of the other options, would that -- would Nova Scotia Power consider that a scope change?

A. (Beaton) Yes, we would. As we discussed yesterday, where it's one of the alternatives considered under the "Why do the project this way," this would qualify as a scope change if we were to change it post-submission.

Q. Okay. Thank you.

Okay. I'm going to move on to Project C0068898 TUC1, Last Stage Blade Replacement Project. Is that you again, Ms. Drover?

A. (Drover) Yes, it is.

Q. Okay.

MEMBER MURPHY: Rob, can you call up Exhibit N-3? That's Response to CA IRs, PDF page 21. And it's response to 11(a). Right there.

BY MEMBER MURPHY:

Q. It says:

> Manufacturing of the replacement blades is complete and the blades will be shipped in time to arrive [at Tuft's Cove 1 by] April 2026. There is a risk of shipping costs increasing beyond the budgeted amount due to the replacement blades being installed at a different shop than originally planned, [that] will be covered [in] the project contingency...

In the ACE Plan Application itself, Nova Scotia Power noted that procurement of the blades, they were ordered in May of 2025, and they were scheduled to be delivered to the shop in November 2025. So I'm getting a little confused by the dates, but were they in fact delivered to the shop in November 2025, or are they going to arrive in April of this year?

A. (Drover) I don't have the specific date that the blades arrived. However, I can say that the blades arrived in time for the work to start.

Q. The work has already started; is that correct?

A. (Drover) That is correct.

Q. Okay. Why are the blades being installed at a different shop than originally envisioned?

A. (MacIntosh) Mr. Murphy, it's likely when we're procuring blades, it's to secure the forging of materials on the market. So you're going out to a large number of raw material vendors to find those forgings. So that's likely the cause of why the change in the location. But we can take those further details away, if you'd like. But typically that is the driver.

Q. Yeah, I don't need anything about that. What I would be interested in, though, is if that resulted in any increased cost.

A. (MacIntosh) No.

Q. If anything, it sounds like it would have decreased the cost?

A. (MacIntosh) Correct. The procurement process with these blades, we went out to look at which vendor would have the shortest lead time for these blades to meet the outage requirement and we went with Ethos, which is not the OEM, just so you know.

Q. Okay. Okay, thank you.

MEMBER MURPHY: Rob, can you call up N-6, page -- PDF page 411, please? That's NSEB IR-80. And leave it right there.

BY MEMBER MURPHY:

Q. So it says -- in the IR itself, it says Board staff noted that in 2023, under another matter, Nova Scotia Power received Board approval to replace five of the L-0 blades with re-used blades and refurbishment of additional two blades, and the cost for that project was roughly -- it doesn't say it here, I don't think, but the cost of that project, I checked, it was roughly $2 million. And then in response to this IR, Nova Scotia Power noted that those blades that were installed as part of that project will be removed from service and replaced with new blades.

I guess I have a couple of questions on that. What's the typical service life for those blades, those five blades that were installed as part of that project?

And maybe I'll just tack on my other question here, is do you know what the unappreciated capital cost of those blades are and would that cost be expensed over five -- since they're no longer used and useful, they were only installed two years ago or three years ago, would the unappreciated capital cost of those blades be expensed per, I forget the accounting policy, 65/30?

A. (Beaton) I'll take the depreciation question. So no, where we depreciate all our assets in a pooled manner. It's expected that certain assets won't reach their typical expected useful life and certain assets will greatly exceed their expected useful life. So we don't complete any write-offs related to depreciation expense unless directed to through a different proceeding, but ---

Q. What is the expected typical life of those blades?

A. (Beaton) So the expected -- turbine blades would be depreciated at the overall plant level. We don't depreciate different assets based on their individual lives. So it would depreciate -- these would get depreciated as part of the broader Tufts Cove 1 depreciation group, which amalgamates all the assets related to Tufts Cove 1 depreciated pool level. For the actual expected useful life of the blades, I think I'd pass that off to Mr. MacIntosh.

Q. That's around 4 percent? Does that sound right for Tufts Cove?

A. (Beaton) Without having it in front of me, it would be in that ballpark.

Q. So you'll have three years of

depreciation on a $2 million project at 4 percent a year. I didn't to do the math on it, but it still leaves a significant portion of that cost that we'll raise in rate base on a return and that the blades were only installed for three years; is that correct?

A. (Beaton) Correct. I think the nature of the C0055376, where that was done as U&U, it was a found issue. And I might rely on Mr. MacIntosh again here, but we wouldn't have had the ability to do a full replacement at that time, so that was still the minimum work required to return that unit to service to allow the unit to operate up until this time.

Q. Okay. Thank you.

I also note in response to -- I don't need to call it up, Rob -- in response to Board IR-83 that Nova Scotia Power noted that a total of five cracked blades were found in the LTP2, LP2 and LP3 during inspection in March of 2025, and then it goes on to say that all 318 blades will be replaced as part of the project. I'm curious why, if only five blades were found to be cracked, why all 318 blades need to be replaced.

[10:10:33] **A.** (Drover) Mr. Murphy, I will start with the answer to the question, but my colleague, Mr. MacIntosh, might add some more context.

So these L0 blades are susceptible to erosion and fatigue due to their location and normal operation over time, and it was determined that the cracking on this blades was symptomatic of a population-wide accumulated fatigue versus isolated issue with those particular five blades. So these blades, as a population, had reached end of life and therefore necessitate the replacement of the full L0 row of blades times three.

Q. Okay. Thank you.

Okay. I just want to talk briefly about C0080135, which is the CTBGT2, A, B, C, D, E, F, engine replacement.

MEMBER MURPHY: Rob, can you call up Exhibit N-6, PDF page 438? That's a response to the Board

IR-99(b). Right there.

BY MEMBER MURPHY:

Q. And it notes, as it relates to this particular engine, it says:

> The OEM's original 1971 guidance-developed for utilities operating the engines at high duty cycles-referenced a nominal refurbishment interval of...5,600 operating hours. For [Nova Scotia] Power's peaking-duty units, degradation mechanisms are primarily driven by long periods of inactivity, short [runs]..., and environmental exposure.

I'm curious how long periods of inactivity lead to unit degradation.

A. (MacIntosh) I can take that question, Mr. Murphy.

So when a unit's offline and not operating you're still going to have life consumption. So inactivity would mean that the unit's sitting static, it's not moving, so you'll still have light consumption that's happening on the machine. So you have offline corrosion. So when the unit's actually operating hot and it's online there's actually less corrosion in that environment than there would be if it's offline and it's colder and it's damp, you get moisture coming into the machine.

Q. Okay. So in that context, would it make sense to run it more often than leave it just sitting there doing nothing? I suppose there would be a cost associated with the fuel, I suppose, but ---

A. (MacIntosh) Certainly the cost of the fuel would outweigh the cost of the corrosion to run that. These units are one of our highest cost energy units to operate them out of dispatch to minimize corrosion would ---

Q. Okay, yeah. In response to Board IR-102 -- I won't get Rob to call it up -- but Nova Scotia Power mentioned an option about perhaps purchasing a previously owned or refurbished engine and opted not to do that, I think based on, you know, cost and some other concerns. But did Nova Scotia Power obtain a quote for a refurbished engine?

A. (Drover) In this case we did not receive a quote on a previously refurbished engine. However, in recent years we have purchased a previous refurbished engine, and we are aware of the cost of those engines on the market and regularly engage with industry. But in this case we do not have a quote.

Q. So based on your history ---

A. (Drover) That is correct.

Q. --- the previous history would have shown that the cost of a previously owned refurbished engine would have been more than the refurbishment cost associated with this project; correct?

A. (Drover) Mr. Murphy, just adding on to my previous comments, as I've mentioned, we do have experience with purchasing previously refurbished engines, and as noted in IR-102, there is significant variability in price.

Q. Excuse me. Are you talking about the CT, these types of engines, or are you talking about the LM6000?

A. (Drover) These types of engines.

And typically there is additional work that needs to be done after market on these engines.

And we also have an additional risk of having complete records, and that is a risk we have experienced in the past, knowing how that unit was run, knowing the servicing and the maintenance and the work that was done on that engine previously. And when we take those items into consideration, refurbishing our engine is comparable or a lower-cost option then buying a previously refurbished engine.

Q. Okay. Thank you.

A. (Drover) A big determining factor is the risk.

Q. Okay. Sticking with this project, in response to Board IR-103 there was a reference to the IRP that's underway by the IESO and whether in fact I think that the results of that IRP would indicate that this particular engine may or may not be required. I don't know. But did Nova Scotia Power give any thought to perhaps delaying this project until that IRP is completed to confirm whether in fact this unit is required?

And I note that there was another IR response, IR-101, from the Board that noted that there's an option available to Nova Scotia Power to use a leased engine from Pratt & Whitney, if needed, to replace this engine.

So, you know, in the interim, until that IRP is completed and the results are available to confirm whether in fact that engine is needed, could this project be delayed until that IRP's completed and if, in fact, the engine is needed that the leased option could be used?

[10:20:14] **A.** (Peachey) And Mr. Murphy, I can take that question.

So in previous IRPs, which is also pointed to in our 10-year system outlook, we're continuing to rely on that fast-acting generation that would be supported by the Burnside units. So that's been demonstrated in our previous IRPs as well, as I mentioned, the 10-year system outlook to support the increase in wind generation. So there's no indication to us at this point that any outcomes from the IRP are going to point to not operating those units in the future.

Even when you look back as far as the 2020 IRP, there was some pre-IRP work as well that pointed to the value of continuing to invest in those diesel CTs going forward to support the Path to 2030 and then, of course, the Plan B on that, so...

Q. So are you saying you're confident that the ISEO's IRP will show that those -- this particular engine will still be required?

A. (Peachey) We are. If you're considering sort of the plan forward and the role that those -- the path forward that the wind is going to take in supporting the long-term plan in meeting those -- the

80 percent RES requirements, we're very confident that those CTs will continue to be part of that portfolio that supplies that fast-acting response to be able to integrate those wind resources on the system, yes.

Q. And one of the risks, I suppose, if -- I think that IRP is supposed to be done relatively soon.

A. (Peachey) Yes.

Q. What are the risks of waiting till that's done until that confirmation's actually provided by the IRP? What are the risks in delaying this refurbishment project?

A. (Peachey) So one of the key pieces that came out of previous IRPs and is part of, actually, the clean power plan that's going to guide us towards meeting those targets is that we need all the capacity that we can get on the system to really support that wind integration, so as we're sort of phasing out coal and, of course, those new CTs are going to be added, we still really need all of that additional capacity that's still currently on the system, which would include those diesel CTs.

Q. How quickly could you get this leased engine? How quickly can you get it, put it in service?

A. (MacIntosh) That depends on the market. So there is a lease engine market through Pratt & Whitney, but it depends on the availability of it. It's not a given.

Q. Okay, okay. Thank you.

I just talked to the Chair. I'm probably going a little longer than I thought I might go, but -- so I think the idea is we might take the break in a few minutes. But there was a couple of questions I missed in my excitement to get to the Tufts Cove Project.

I missed a couple of questions, so I'm just going to go back to them. They won't take too long.

MEMBER MURPHY: Rob, can you call up

Exhibit N-6, PDF page 47?

This is response to Board IR-16(a).

BY MEMBER MURPHY:

Q. In this response, Nova Scotia Power provided a table that identifies the carry-over projects from Figure 17 of the ACE Plan. And it identifies projects that have a total estimate now that exceeds the Board's approved amount by the ATO threshold.

I just had a question on the Marshall Falls Project. It was approved in 2020 for 5.4 million. You can see it there. And according to the capital of project status update from last year's ACE Plan, spending on the project was about $582,000.

In Exhibit 10 of this year's ACE Plan, which is the Q4 capital reports to December 31st, 2025, spending on the project was about 675,000, suggesting that not a lot has been spent on the project in 2025.

So two questions. What's the status of the project and why has it been delayed for five years, and is that delay having any impact on the cost of the project?

A. (Drover) So that project is -- the Marshall Falls Dam Project is on the same hydro system as the Ruth Falls Dam Project. And the Marshall Falls Project will not commence work until the Ruth Falls Project is finished.

And we have had numerous communications with the Board on the status of the delays at the Ruth Falls Dam Project with regards to getting the required *Fisheries Act* authorization under the modern *Fisheries Act*, which led to the delays of that project. And given that the both projects are on the same hydro system, the Marshall Falls Project will not commence until after Ruth Falls is completed.

Q. So does that suggest that that current estimate of 13.8 million will likely go up?

A. (Drover) The updated project estimate incorporates our learnings from the Ruth Falls

Dam Project and all of the requirements under the modern *Fisheries Act*, so as we continue on with the detailed design work for that project and as we finish Ruth Falls, we may have more learnings, but at this point in time, we have incorporated learnings from that Ruth Falls Project which leads to the difference between the current approved amount and the current project estimate.

Q. Okay. Thank you.

MEMBER MURPHY: Rob, if you can scroll down a little bit, just a quick question on that Wreck Cove Tailrace Rock Bolting Phase 2.

BY MEMBER MURPHY:

Q. In this update, it shows the estimated project cost at completion of 5.720 million [*sic*], which is actually -- the project was approved in 2024 for 15.722 million, so it's actually very close to the approved amount. But I'd note in -- you can call it up if you want, but in Figure 17 of the actual ACE Plan Application, which was filed in December 2025, the estimated cost was 13.8 million. And now we're in February of 2026 and the cost has gone up, let's call it, two million.

What's the reason for that increase in less than two months?

A. (Drover) The Tailrace Rock Bolting Project, there was execution of that project throughout 2025, and that work will resume again in 2026 and result at the end of this year.

So there is a period through 2025 getting to the end of that portion or that phase of the program, understanding where we currently sit, understanding what work is remaining for this year, and reforecasting and understanding the amount that is left for 2026 and updating those associated forecasts would be a driver for the change in forecast.

Q. But the other cost estimate was provided as of December. Why wouldn't those costs have been projected in December?

A. (Beaton) So generally, project total or project estimates included in carry-over tables like this one are primarily from our Q3 forecast completed in the summer. So while it was filed in December, it would have been taken from forecasts a number of months prior.

Q. Okay. Thank you.

MEMBER MURPHY: Okay, Mr. Chair. I think that might be a good place to take our break. I only have probably seven hours of questions left, so...

THE CHAIR: Okay. Let's take a break for 15 minutes and come back at 10:45.

--- Upon recessing at 10:29 a.m.

--- Upon resuming at 10:45 a.m.

DAVID ARTHUR PICKLES, Resumed:

TREVOR ARCHIE BEATON, Resumed:

LYNNE ANNE DROVER, Resumed:

JONATHAN ROSS CLARK MacINTOSH, Resumed:

CHARLENE DEEANE (Sp?) MacMULLIN, Resumed:

ERIN CHRISTINE PEACHEY, Resumed:

THE CHAIR: So we're back on the record. I'll turn it back over to Mr. Murphy.

MEMBER MURPHY: Thank you, Mr. Chair.

QUESTIONS FROM MEMBER MURPHY, (Cont'd)

Q. I'm going to move on to some questions about routine D010, Provincial Widening and New Distribution Right-of-Way, Phase 11.

So I don't know. Is that you, Mr. Beaton or Ms. MacMullin for ---

A. (Beaton) Likely a combination of both.

Q. Okay. I may have asked this question in prior ACE Plan proceedings, but as a refresher maybe, because I don't actually recall if I did, in fact, ask it, but can you please explain to me why expenditures under D010 and the New Distribution Right-of-Way, Phase 11 and prior phases, why those are considered capital expenditures rather than operating expenditures?

A. (Beaton) Certainly. So in the case of both instances, we treat our right-of-ways as an asset. So in both those instances -- well, different -- and I'll speak to D010.

First, today, there's a defined right-of-way in place, generally 10 feet on the forest edge of the line. So our asset in today's case would be a 10-foot right-of-way. We are then taking the 10-foot right-of-way, increasing it to between 15 and 20 feet, depending on our ability to gain permission from landowners.

We then have to maintain that asset on a go-forward, which is done through our Maintenance Program, but there is benefit to trading that asset for a very long period of time. So where there's benefit of the asset greater than one year, and obviously much beyond that, there's a multiyear value to it, so it's treated as a capital asset.

And then in a very similar manner on the new right-of-way, there's no right-of-way there today and we are creating a new right-of-way anywhere from 10 to 15 to 20 feet on the forest side of the line.

And then all future work in that space will be maintained through our Tree Trimming Program which is an operating expense. But, again, the creation of that right-of-way is creating a multiyear benefit that customers, not just in this current year, but all future years, will gain the benefit of.

Q. Okay. In the traditional sense of an asset, though, I mean, the right-of-way is not -- the land on which the right-of-way runs isn't owned by Nova Scotia Power, right? It's owned by someone else. So in the traditional sense of an asset, right-of-ways aren't assets owned by Nova Scotia Power?

A. (Beaton) Correct. They're not typical as a general tangible asset would be in most cases, but they're certainly -- there's an added benefit to them and that multiyear, multigenerational value that you get from that either traded or increased right-of-way meets the definition for a capital expenditure.

Q. Okay. And I assume this has been -- I don't know what the word is, approved, or it falls in line with standard accounting practices?

A. (Beaton) Correct, yeah. This has been -- it was heavily vetted and heavily discussed with our finance folks when we first implemented the new right-of-way program and obviously the D010 routine has been going on much longer.

Q. Okay. Okay. Thank you.

MEMBER MURPHY: Rob, can you call up Exhibit N-8? That was a revised response to the CA's IR-19.

BY MEMBER MURPHY:

Q. In the IR, the CA ask Nova Scotia Power to provide the number of outage events by year and tree contact outage events by year, for each feeder listed in Attachment 1 of the Application. And I think that attachment is on PDF page 413 of N-1. We might go there in a second.

[10:50:03] **MEMBER MURPHY:** But if you scroll down to the response, Rob, the next page down?

BY MEMBER MURPHY:

Q. The feeders that are listed there appear to me to be actual targeted feeders for 2026, rather than the feeders that were listed in Attachment 1 of -- or, sorry, in Exhibit N-1.

MEMBER MURPHY: Maybe, Rob, you can go to Exhibit N-1. It's PDF page 413.

Actually, maybe scroll up a bit, Rob. Keep going. Keep going. Okay. Stop.

BY MEMBER MURPHY:

Q. So these are the targeted circuits for that particular project for 2026, and I think in the response to the CA's IR, you provided the information related to these particular feeders, but the question asked for the information related to the feeders that were identified in Attachment 1.

MEMBER MURPHY: If you scroll down, it's a number of different feeders. Keep scrolling. Go to 413, Rob.

BY MEMBER MURPHY:

Q. I think there was -- I didn't do a count on it, so maybe there's 50 feeders listed in this one and only 20-some in the targeted.

So I just want to confirm whether that's correct. If it is, in fact, correct, as an undertaking, can we get the response to the CA's IR, as it relates to those feeders in Attachment 1?

A. (Beaton) So one thing to clarify, which may assist here, the feeders listed in the attachment we're looking at now are the feeders that had work completed on them in 2024. So as part of one of -- we would have had a directive to show the condition improvement related to all distribution projects over $1 million whenever we file a project. That's what this is showing.

So as a part of this capital initiative in the new right-of-way program, we're showing the condition improvement on work completed under this program in 2024. It's the last full year we would have had to refile the ACE Plan.

So this list is showing that -- were feeders where we completed capital work in 2024, the change in the feeder condition score. So this list should not match the list a few pages above on the target feeders in 2026.

Q. No, I understand that.

A. Okay.

Q. But I think the CA's question was to provide these -- and I don't want to speak for the CA, but I think the question was to provide the tree contacts and outage events for a year by the feeders listed in Attachment 1, not the targeted circuits.

And I think, in my opinion, that would be more useful information, to see if these were, in fact, feeders upon which vegetation management was conducted in 2024. It would provide useful information to show the tree contacts and the outages on those feeders as a result to completing that vegetation management.

A. Can we just jump back to the IR, just quickly?

Q. Yeah.

MEMBER MURPHY: N-8, yeah. Scroll up to the question, Jeff -- or Rob.

BY MEMBER MURPHY:

Q. You can see there it says:

> Please provide the number of outage events, by year, for each feeder listed in attachment 1.

MEMBER MURPHY: And if you scroll down, Rob?

BY MEMBER MURPHY:

Q. I think the feeders that are listed there are the feeders that are the targeted feeders for 2026. They're not the feeders in Attachment 1.

A. (Beaton) Fair. Yeah, we can certainly undertake to amend that to match the feeders that are included in Attachment 1.

Q. And can I also -- I don't know if it's available yet, but as part of that undertaking, can you include the condition rating for those -- the 2025 condition rating for those feeders?

A. (Beaton) Yes.

THE CHAIR: Okay. So this would be U-18. And it’s to review the IR response to the CA IR-19?

MEMBER MURPHY: The revised IR.

THE CHAIR: The revised IR-19, to compare it with the actual request that was made in IR-19 to make sure that the response is correct, and then to also add the...?

MEMBER MURPHY: Condition rating for those -- the 2025 condition rating for those feeders.

THE CHAIR: The 2025 condition rating for the same feeders.

UNDERTAKING U-18 - To review the IR response to the revised CA IR-19, compare it to the actual request that was made in IR-19 to make sure that the response is correct, and then to add 2025 condition rating for the same feeders

MEMBER MURPHY: Okay. Thank you.

Rob, can you go to Exhibit N-6, PDF page 67? Five sixty-seven (567).

BY MEMBER MURPHY:

Q. And this table provides the cost for D001, a new right-of-way spending for each year from 2018 to 2025, and it provides the number of kilometres completed associated with each one of those years. And if you trust my math for a second, when I look at those numbers and I do the calculations, it strikes me that from 2019 to 2023 inclusive, the cost per kilometre was -- fell between roughly 33,000 and $56,000 a kilometre. If you want to take a second to confirm that math, or...?

A. (Beaton) Okay. We just double checked.

Q. Okay. So from 2019 to 2023, the cost per kilometre for those programs fell between 33,000 and $56,000 per kilometre. However, for 2024, if my math is correct, the cost goes to $97,000 per kilometre, and in 2025, it goes to $119,000 per kilometre. So my question -- assuming my math is correct, my question is, can you tell me the reasons for that pretty significant increase in cost per kilometre?

A. (Beaton) So we certainly acknowledge we've experienced significant cost increases on the capital side of our Vegetation Management Program. As with many industries, they've battled inflation, the cost of their machinery and equipment has gone up substantially, and their ability to maintain resources is a significant challenge that they struggle with, and we've had to -- they've been forced to increase their rates fairly substantially over the last number of years in order to maintain a full complement of resources, which is -- remains a struggle every day. I would want to take it away as an undertaking to speak specifically to the last two-year increases.

Q. I may ask for that. I understand what you're saying about inflation and whatnot over that period of time, but in 2023, the cost per kilometre was about $56,000 and then in 2024 it went to $97,000. That's a little bit more than the rate of inflation, I would think. And then from 2025 -- sorry, from -- yes, from 2024 to 2025, $97,000 a kilometre to $119,000 a kilometre is another 22 percent increase, which again I think is a little bit higher than, you know, inflation concerns.

[11:00:15] **A.** (Beaton) So I do want to take it away. The last two years are causing me a bit of confusion, to be honest, because the numbers are -- in this table are showing higher than we showed elsewhere.

So I do want to take that away.

But just going back, just to answer the question, in a more broad sense, on the other reasons why the program has experienced these costs, we have changed -- which we've put on the record, we've changed the way we do the work as well. We're much more aggressive in the amount of trees we're removing beyond the right-of-way, and once you get into removing those trees on an individual basis, it does get more time consuming for kind of area you're getting.

So certainly the increased cost we've seen, and what we've discussed yesterday as part of the right-of-way program, we feel are well justified, but I do think it's best if I take that away in an undertaking to provide more detail.

Q. Okay. I think ---

THE CHAIR: Okay. So the undertaking will be U-19, and it will be to provide more detail on why the cost per kilometre in -- for 2024 and 2025 on the

"D010 and New ROW Spend" for Table 1, why it went up by so much between -- from 2023 to '24 and '25.

UNDERTAKING U-19 - To provide more detail on why the cost per kilometre for 2024 and 2025 on the "D010 and New ROW Spend" for Table 1 went up by so much from 2023 to 2024 and 2025

MEMBER MURPHY: Okay. Thank you.

Jeff, can you go to PDF page 571, please? Jeff; I keep saying Jeff.

MR. NORWOOD: I'll change my name to Jeff.

BY MEMBER MURPHY:

Q. Okay. This is a table Nova Scotia Power provided in response to Board IR-29. It provides outage statistics, tree contact -- or event outages caused by tree contacts, customer hours of interruption by tree contacts, and customer interruptions caused by tree contacts from 2020 to 2024.

Can you confirm for me that these -- this particular table includes outages caused by MEDs and EEDs? It's all-inclusive numbers?

A. (MacMullin) Subject to check, but certainly the numbers there do look inclusive of MEDs.

Q. And EEDs?

A. (MacMullin) Correct.

Q. Okay. And can you confirm for me that in 2021 and 2024, there's no MEDs or EEDs in either one of those years?

A. (MacMullin) Correct.

Q. Okay. Thank you. So I want to focus on 2021 and 2024, given that those particular years in this table had no MEDs or EEDs, so we would -- I suppose we'll call them, for the moment, sort of normal weather conditions, or the conditions that, I suppose, Nova Scotia Power reports, in terms of its performance standards.

So the Chair told me he'd give me a little indulgence. Rather than kind of flipping between IRs, because my questions on this particular topic span a couple of IR responses. I made a little table to summarize those responses.

MEMBER MURPHY: So Rob, if you could call up my -- the graphic I sent you. It's called "Graphic 1".

THE CHAIR: Again, like the tables that were prepared by the Industrial Group solicitor, we're going to simply mark these for identification purposes. The evidence -- these numbers, as I understand, come from the IR responses and from this actual Application, so the evidence is not this, the graphic, but the actual evidence. If it turns out that these are incorrect numbers, then it is what it is.

So the evidence is what's in the Application and what's going to be said on the stand. This is simply for identification purposes.

So what exhibit number are we at? N-21.

--- EXHIBIT NO. N-21:

NSEB IR-128(a) Response - Graphic 1 NSEB

BY MEMBER MURPHY:

Q. So again, it does say in here where the information comes from as it relates to the responses to the IRs, and how some of the other numbers were determined, but, again, I just want to focus on '21 and '24 because those are the years where there was no MEDs or EEDs.

So you can see from 2021 to 2024 the number of tree contacts have declined and the number of tree contacts on lines on which vegetation management work was completed have declined. And that particular column came from the response to NSEB 128.

So that's fine. But if you notice, in terms of customer interruptions and customer hours of interruptions in those two years where there was -- again, where there was no MEDs or EEDs, customer interruptions increased from ’21 to ’24 and customer hours of interruptions increased from ’21 to ’24.

And in addition to that, the average -- this is my calculation, and you’re free to check it if you want. The average customer outage duration from tree contacts increased from 2.83 to 2.98.

So in addition, based on my calculations, the percentage of tree contact outages resulting -- or on lines that had vegetation management work represented roughly 72 percent of the total tree contact outage events in 2021 and 68 percent in 2024. And again, you’re free to check that math.

So in summary, I guess, between 2021 and 2024, the work that was done on the lines on which vegetation management was completed resulted in roughly a 3 percent decrease in tree contacts over that three-year period but, again, the customer interruptions increased and the customer hours of interruptions increased.

So -- and over that period of time, I believe $57 million was spent on D001 and the right-of-way work.

So in that context, as it relates to normal weather conditions, can you tell me how ratepayers have received the -- a good bang for their buck for that $57 million?

A. (MacMullin) So a couple of important items for context when evaluating the numbers in this table.

So again, subject to check, but your math looks good to me.

So first of all, the operating conditions of the system in 2021 versus 2024 were not held constant, so the number of hours of wind gusts above 80 was around 100, approximately, versus closer to 70. So you're looking at a -- you know, a substantial ---

THE CHAIR: Sorry. I just wanted to

make sure I understood that.

So which years are you talking about when you're talking 80 and 70?

MS. MacMULLIN: Sure. In 2024, we would have had higher number of wind gusts over 80 versus 2021. So around 100 hours of wind gusts over 80 in 2024 and closer to 70 in 2021. So we're looking -- and again, that is just one datapoint, certainly.

We understand how wind gusts are measured. They're measured at the top of the hour at representative stations. We know that the way wind works that within that range some areas can have much higher gusts and some can have lower, so -- but what that is, is a really good indication of the intensity that this -- and the types of conditions the system is exposed to. And it's a good proxy to understand what we're operating under.

[11:10:14] So right off the bat, we know that 2024, we -- so while we held essentially constant in terms of what we were seeing in terms of tree contacts -- outages due to trees, but it was in a much more severe operating condition.

And I think, you know, that, again, when you're evaluating this, it's really important to consider that factor.

BY MEMBER MURPHY:

Q. I understand what you're saying, but, you know, I think it was Mr. Dandurand and I had this conversation last year and the expectation, I think, from the Board, and certainly from customers as well, is that, you know, there's improvement expected from Nova Scotia Power in face of the increasing severity of weather.

So I understand that there was different operating conditions, but the expectation is, regardless of that, there's an expected -- there's to be an expected improvement under normal weather conditions. And when you look at this table, as it relates to customer interruptions and customer hours of interruption and the average duration, there's not really an improvement from 2021 to 2024 and there was $57 million spent.

A. (MacMullin) So it is absolutely the intent of the investment program, the $45 million last year and the $45 million this year in vegetation management, that we are -- we are prioritizing on that work on the areas that we feel will have the biggest impact on the -- reducing the duration and frequency of outages; moving the trees away from the line.

We have absolutely seen that benefit and we have that quantified. So year over year, 2025 versus 2024, we have about a 19 percent reduction in outages due to trees. So customers are absolutely reaping the benefit of those investments.

And we have seen some of the best performance since 2020 with duration when it comes to tree contact, so we have -- we have evidence that has been presented that the program is reaping benefits.

Again, this particular snapshot is

looking at -- so we're particularly looking at the feeders and the contribution of outages due to trees from the feeders that we've chosen to prioritize for this work, which means by their nature these are feeders that we identified that were contributing to duration and frequency of outages because of trees.

So you're looking at a subset, so -- of the system, a small subset of the system, that had already been identified as having issues and these -- that -- which is why we're targeting it. And then again, we're just looking at the analysis in terms of what are the contributions of those feeders to outages.

And so it -- you know, when you think of all of those things, and that's important context when evaluating the program. But from our point of view, we know that we are prioritizing the highest risk areas and we are absolutely seeing a decrease in the duration and frequency, as evidenced in our results in 2025.

Q. I suppose what would be

interesting would be to see the -- would be to see the number of customer interruptions and customer hours of interruption on those lines on which vegetation management work has been done; in particular, you know, from my -- from what I'm interested in for '21 and '24.

And unfortunately, I don't think that was provided in the response to IR-128. I think what was provided was, you know, the percentages of customer hours of interruptions. There was a percentage of tree contacts, I think, or just -- percentages were provided rather than the actual number of hours of -- customer hours interruptions and CIs.

So as an undertaking, I'd like to get that information. So I'd like to get number of customer interruptions, CIs, and the number of customer hours interruption. Let's go for each year from 2020 to 2025 on the lines on which vegetation management work was completed. And I think those are the lines that are provided in response to IR-128.

A. (Beaton) Just for a point of clarification, on lines that were completed in each calendar year or in the years preceding?

Q. Just with the lines that were identified in 128.

THE CHAIR: Is it possible to bring up that IR-128? I know it's a long series of -- it's a number of lines listed there, but I think ---

MEMBER MURPHY: Yeah, you can bring it up.

THE CHAIR: I think we'll use that as a reference point, because clearly the numbers should be available since to calculate the percentages you have to have real numbers, you have to have the denominator to calculate the percentage.

MEMBER MURPHY: Go to N-6, Rob, and maybe ---

MS. MacMULLIN: We'll endeavour, absolutely, to undertake that to provide that.

And I think again it's important to understand that when work is completed -- so if we have work that's scheduled to be completed in 2021 and you wrap it up in November that you may not immediately see the -- you know, the benefits in that year.

So certainly we'll looking at providing that, I think, to the intent of what you're looking for, which you're looking for a demonstratable benefit.

BY MEMBER MURPHY:

Q. Exactly.

A. Yes. Understood.

THE CHAIR: So it will be essentially to provide the information, as Mr. Murphy has described, with respect to the lines that are set out in the attachment to IR-128 -- Board IR-128. That's U-20.

UNDERTAKING U-20 - Re Board IR-128, to provide the number of customer interruptions and the

number of customer hours interruption for each year from 2020 to 2025 on the lines on which vegetation management work was completed

THE CHAIR: And obviously if there is any commentary you want to make when you're responding to undertakings, you can put those commentaries as well, but you've already made most of those on the record anyway.

MEMBER MURPHY: Okay. Thank you.

One last question on this routine.

Jeff -- Rob, if you go to 577. Every time I say Jeff from now on you can fine me a quarter. Is that 577? Okay.

BY MEMBER MURPHY:

Q. In this particular IR -- I'll read it out. It says:

> Board staff analysis of Attachment 1 reveals that the utility work on 71 feeders, totalling 753 [kilometres]. Out of these 71 feeders, 23 feeders, totaling 215

> [kilometres], maintained, or worsened, their original ranking even after vegetation mitigation [management] work. Please provide the cost of vegetation management work performed in 2024 on the 21 feeders described above.

MEMBER MURPHY: And if you scroll down to the response, Rob. Right there.

BY MEMBER MURPHY:

Q. It says:

> The total kilometres completed in 2024 on the capital program is 940 [kilometres] as a total cost of [$30.8 million].

I don't think that response actually answers the IR. I think that $30.8 million was the total spent on the -- if we went back to that table I referenced in 128, that was the total spending on the ---

A. (Beaton) That is correct, yes, sir.

Q. So I'd like to get as an undertaking the response to the IR which asked for the spending, I think, on those -- well, the IR says 21 feeders, but I think it's 23 feeders.

A. (Beaton) We'll endeavour to. Again, going back I think we need to make sure that we've got that data available in the wake of the cyber event for 2024 investment. (Inaudible due to mumbling) to make some assumptions potentially, but we can certainly provide a table.

Q. Okay. Thank you.

THE CHAIR: Okay. So the Undertaking U-21, which is to provide the table -- just go back to the -- to actually respond to the question that was in IR-132, if the information is available.

UNDERTAKING U-21 - To actually respond to the question in IR-132

MEMBER MURPHY: Okay. I think the Chair had a question before I move on.

THE CHAIR: It had to with -- and I know we've gone through this before with respect to the increasing wind speed and the datapoints that are used that are from, I think, Environment Canada, but does Nova Scotia Power have its own wind -- system collecting information on wind that goes beyond the Environment Canada information?

[11:19:58] The reason I ask is because many years ago when the wind farms were first being introduced there seemed to be a lot of data on wind. I'm not sure if that came from third parties or how that was accumulated. But just trying to cite the wind farms there was a lot of data that seemed to go well beyond what Environment Canada provides, or those five datapoints, so that's why I ask.

(SHORT PAUSE)

MS. MacMULLIN: Do you mind repeating the question, just to make sure I'm on track?

THE CHAIR: My question is essentially whether Nova Scotia Power has its own wind data collection systems that go beyond what is provided -- what Environment Canada provides and what you're using as your five datapoints for a lot of the discussions that take place around wind?

MS. MacMULLIN: So we do not. Nova Scotia Power does not have independent or our own wind collection devices. Your reference to wind farms, in cases such as that there are third-party engagements where they would do specialized analysis, which is separate. But we would rely on the established monitoring sites as available from Environment Canada, and then there are several forecasting agencies that would use that data and then make decisions based on what they're seeing.

THE CHAIR: Okay. Thank you.

MEMBER MURPHY: Thank you, Mr. Chair.

BY MEMBER MURPHY:

Q. Okay. I'm going to move on. I have a quick question. I wouldn't normally ask a question on an item for subsequent submittal, but -- because we can ask relevant questions when they're submitted for approval. But I did have one question on the Tusket 1 Overhaul Project CI49595. And my first question related to that is would that project be required if Tusket was decommissioned?

A. (Drover) Yes, that project would be required in order to manage water in either case.

Q. In either case. Okay. Thank you.

All right. I'm going to move on to the Five-Year Reliability Plan. I have a few questions on that.

MEMBER MURPHY: Rob, can you call up Figures 4 and 3 from Appendix G? That's N-1, pages 714 and 715. So just stop there for a sec.

BY MEMBER MURPHY:

Q. That's the -- I think we talked about this figure yesterday -- annual customer hours of interruption from tree contacts. And scroll down to Figure 4, and I that's, I think, annual hours of interruptions due to failure of equipment.

And I just want to confirm, as it

relates to those figures, that the numbers in those figures exclude any impacts from MEDs and the EEDs.

A. (MacMullin) That's correct.

Q. Thank you.

MEMBER MURPHY: Rob, can you call up Exhibit N-7, PDF page 30? That's the response to the SBA IR-18.

BY MEMBER MURPHY:

Q. Okay. In this response, Nova Scotia -- I think Ms. Powell talked about this figure yesterday a little bit. Nova Scotia Power provided an update to Figure 68 from the ACE Plan with updated numbers for 2025. And perhaps it's a bit of a minor point, but the figure -- this particular figure for 2022 shows about 810,000 hours of customer interruptions in 2022, but the figure in N-1 at 714.

MEMBER MURPHY: Can you just flip back to that real quick, Rob?

BY MEMBER MURPHY:

Q. It shows for 2022, I don’t know, 760,000. All the other years look about right, but that year looks to be off a little bit. Is there an explanation there?

A. (MacMullin) So the difference between the two, so the figure with major and extreme removed is different from performance standards because performance standards also excludes SEDs when they follow an MED and planned outages. So there would be a small difference between a figure that is just showing major and extreme events and a figure that is reflecting the value for performance standards, which also excludes planned outages and significant events when they follow a major event.

Q. Okay. So is it the -- which is the figure that excludes those other ---

A. (MacMullin) Fair. So in Appendix G, Figure 3 is excluding planned, major and extreme, and sometimes significant, and the figure in the main body --

or the figure in your -- in the -- I believe the response to the CA, that is just major and extreme events. So I would expect the Figure 3 to have a lower value in some cases due to the planned outages being excluded in that one versus the other.

Q. Okay. All the other numbers are the same, though. Was there no planned outages in the other years? Or they look to be the same.

A. (MacMullin) I would suspect that it's due to the representation of since we are looking at a bar graph as opposed to a numerical value.

Q. So there might be a little difference. Okay.

MEMBER MURPHY: Can you go back to that Figure 68 -- the revised Figure 68 there.

BY MEMBER MURPHY:

Q. Ms. Powell talked about this yesterday and I want to talk about it again very briefly.

The trendline, as Ms. Powell noted

yesterday, in the Application was going the other way. It was a decreasing trend. Now it shows an increasing trend from 2026 to 2025 as it relates to tree context and customer hours of interruption with MEDs and EEDs removed.

And I suppose you explained it a bit yesterday, but I just wanted to put a little more context on it based on the numbers that were presented in response to Board IR-28. Nova Scotia Power spent 126 million on D010 and new right-of-way spending between 2018 and 2025, so quite a bit of money in those years, and the trend is increasing.

So I understand the response you gave yesterday to Ms. Powell, but I'm going to ask it again in that context, that there was 126 million spent and the trend is getting worse, at least as is reflective of customer hours of interruption.

A. (MacMullin) So again, really important context when we're looking at Figure 68 is to understand what happened in 2022 and then again in 2023 where we experienced two large hurricanes. So when we have catastrophic events that hit the system like Hurricane -- like Hurricane Fiona, we have hangover impacts. So it absolutely -- in the months and even up to a year afterwards, we see weakened condition on trees that continue to impact our infrastructure afterwards.

And so again, it's just really important context when you're looking at it. So we're not looking, again, at the operating conditions of the system as being held constant as we're evaluating the impacts of our investments. So the investments are counteracting the effects of extreme operating conditions and catastrophic storm conditions such as the winds that we experienced during Fiona.

[11:30:08] **Q.** I understand that. But again, with respect to the performance standards, I guess, I'm more concerned about normal weather.

Again, this trend is going the wrong way, for $126 million. And I might even -- and I'm only guessing here, but if I took ’22 and ’23 out, the trend still might be going the wrong way.

A. (MacMullin) So again, when we look at real performance of the system, we have seen about a 19 percent reduction in outages year over year.

Q. That’s inclusive with MEDs and EEDs, right?

A. (MacMullin) Subject to check, I believe that’s performance standards data, but I need to double check.

Q. Well, this is performance standards data, isn’t it?

A. (MacMullin) Just one moment.

So I will undertake -- I’ll just double check that momentarily in terms of whether or not that is inclusive or not of performance standards data or whether it’s inclusive of major/extreme. But what we are seeing -- just to get to, you know, what we’re looking at, so absolutely we know that the investments that we’re doing are showing benefits. We are seeing -- we absolutely are seeing a reduction in the duration and frequency of outages due to trees. It has -- it is evidenced in the data and in the evidence that we've presented to the Board.

When we're looking at the parameters in which the system is operating in, we have seen much more exposure to higher winds and that does -- that is something that, again, when my colleague, Mr. Beaton, is talking about the way that we've changed in how we're presenting the program, that is in response to that. So when we have Vegetation Management Program looking at a kilometre, looking at a span, we are looking at it differently than we did five years ago where we're saying can we go a bit further off right-of-way, can we negotiate with customers to get trees that we know from our skilled foresters and arborists are at risk due to the nature of their species and, you know, the way that they are presenting in nature that they would understand that they would be at risk of damage due to wind. And so we're going after those.

And those are the types of things that we -- that are now starting to reap that benefit.

Q. Perhaps when you're talking about the dramatic improvement, maybe you're talking about from '24 to '25, and I'll give you that based on this graph. But from 2016 to 2025, inclusive, this particular figure is not showing that in terms of customer hours of interruption.

Yes, there was an improvement from '24 to '25, and I recognize that. But over the long term, for $126 million, this graph doesn't show that. Would you agree?

A. (MacMullin) What this is -- just a moment.

So when we are looking at the overall performance and when we're considering the context, we absolutely cannot remove the consideration of the operating conditions of the system.

So we know that the operating conditions of the overhead system have changed in terms of the impact of the higher number of winds and gusts above 80 that we're experiencing. It's gone up. It's a different climate. It's changing. And they're the resultant, on an overhead system, of a storm like Fiona followed up by a storm like Lee is not net zero. It has a huge impact on the impact of our program and how our assets are able to operate after being exposed to conditions such as that.

And so when we're looking at this and when you're looking at the investments, the substantial investments in the system over that time, it is not -- when we look at the fact that we have still seen a benefit year over year in light of the changing conditions, that is a result. The system is reaping benefit in terms of just holding its own, which it isn't. It is absolutely showing benefits. It's showing a reduction.

But in light of the intense catastrophic system and winds that we experienced in 2022 and 2023, it is definitely showing that it's having benefit and it's causing less impacts to the system. Every time we clear a span, that is a benefit to customers, and we know that we are prioritizing the spans that have the biggest impact.

We are -- we've shown evidence with visuals, with photos to show what a span looks like before it's cleared and after just to -- you know, just to make it -- and I think probably, as you've driven, you've probably seen the impact where we've been in communities. And so those things, there is no question that they reduce the number of -- they reduce the overall exposure of that line the next time that works -- we experience snow, ice secretion and those winds.

Q. Okay. I don't want to rehash what we talked about previously. I'll move on a little bit.

MEMBER MURPHY: Rob, can you call up Exhibit N-6, PDF page 89, please? And that's a response to Board IR-35(d).

And that's -- yeah, right there.

BY MEMBER MURPHY:

Q. I don't want to read the whole thing, but I'm just really interested in the last sentence. It says:

> However, previously stated assumptions indicate that approximately 80 percent of tree contacts originate from outside the maintained right-of-way.

And my question, really, is, does that sentence suggest that Nova Scotia Power's efforts on D010 and the new right-of-way widening is only going to address 20 percent of the tree contacts?

A. (Beaton) No, I wouldn't characterize it like that.

Any time we remove -- or increase the width of our right-of-ways in a situation where there's creating new or widening current, it's lessening the likelihood of tree fall-ins. In addition to that, the new approach or assessing potential hazard trees based on species, condition, current environment will then further lead to reducing the threat of fall-ins.

But it’s certainly important to understand that the right-of-way widening program or creation of right-of-way program isn’t intended to eliminate tree outages. We’ll never be in a situation on our distribution system where the right-of-ways are going to be wide enough to completely mitigate the risk of tree fall-ins. So they will continue to be a threat that we’ll manage. But certainly one shouldn’t assume we’re only removing 20 percent of the threat through this program.

Q. I suppose over time, then, that that 80 percent number, you would expect that to decline.

A. (Beaton) Likely, yes. It would also obviously depend on the total number of outages based on the benefit of the non-widening or capital program.

Q. Okay. Thank you.

MEMBER MURPHY: Rob, can you to N-1, page -- PDF page 709? Right at the bottom.

Maybe scroll up so we can see the top of the next page, too.

BY MEMBER MURPHY:

[11:40:04] Okay. It says -- I'll read it out. It says:

> The system is already responding positively to this work with an observed improvement to performance standard metrics. As of October 31[st], there is a 53 percent reduction in customer [hour] interruptions and a 29 percent reduction in customer hours of interruption due to device failure in 2025 over 2023 levels.

MEMBER MURPHY: And if you go to PDF page 715, Rob, you can see that the figure basically confirms that statement.

But I wanted to go back to the SBA's IRs. If you can go to IR-7 -- Exhibit N-7, PDF page 40, Jeff [*sic*]?

Just scroll down so we can see that figure.

BY MEMBER MURPHY:

Q. So you can see the bar for 2025 has changed as it relates to customer hours of interruption from failure of equipment.

So in the Application, Nova Scotia Power stated there was a 29 percent reduction in customer hours of interruption due to device failure in 2025 compared to 2023. But based on the updated figure, would you agree with me that the reduction is only really 6 percent now?

A. (MacMullin) It's correct. The numbers that were initially referenced were year-to-date end of October and, at year end, we -- the reduction was lessened.

Q. And you would agree with me that the numbers for 2025 are similar to 2021 and actually worse than they were in 2020.

A. (MacMullin) That's correct.

Again, the difference between 2025 and

2021 is the number of hours of gusts above 80 that the system was exposed to.

Q. And again, I will reiterate it, the Board expressed this last year, that its expectation is Nova Scotia Power will improve in light of those increasing severity of winds and weather.

A. (MacMullin) That is absolutely the goal of the Five-Year Reliability Plan. The goal is to have a sustained demonstrated benefit of reduction in the duration of outages and be consistently meeting performance standards by 2029. So absolutely the goal and the stated benefits of this plan are to meet that.

Q. Okay. Thank you.

MEMBER MURPHY: Rob, can you go to N-6, PDF page 587? That's response to the Board IR-137(c). Let's just see the question first.

BY MEMBER MURPHY:

Q. The question was:

> Please explain how the Board should assess the effectiveness of the 10-year Vegetation

Management Plan when addressing the further vegetation management plans proposed by [Nova Scotia] Power.

And if we scroll down to the response, right there, it says:

Measuring the success of the program should be considered from a risk point of view. Creating adequate vegetation separation will reduce the risk of an outage caused by vegetation in conflict with energized conductors. Continuing to target off right-of-way hazard trees will also continue to reduce risks of outages caused by fall ins. All...proposed [future] vegetation plans will continue to focus on reducing risk and providing safe and reliable service for customers.

Q. My question is, can you describe to me how this reduction in risk can be measured so the Board and customers can determine the effectiveness of the future vegetation management plans, particularly as it relates to costs?

A. (Beaton) Certainly. So when we speak about risk in this scenario it's really vegetative condition on the line, and in any situation where we're completing this work we are improving that vegetative condition on that section of the line. You may not see the overall -- depending on how much work is done you might not see an overall impact from a vegetative score and the 1 to 5 scale of change, but in every situation and every span we complete we're improving the vegetative condition and thus reducing the risk of a tree fall-in.

We continue to get much better insight on the condition -- vegetative condition on our system. We now have, through our initiative with a satellite imagery company, a very detailed condition of the entirety of our vegetation system, which we've explained in the Application and IRs. So we're very confident that in every situation that we complete this work where we're reducing the risk of a tree contact or a tree fall-in, we are avoiding outages that otherwise would happen in the future. So while we may not, on an individual feeder, see -- in a given year see fewer tree contacts compared to a prior year, or any other year that one compares to, we remain very confident that we will see fewer tree contacts than we otherwise would have.

So similar to many of our investments where we endeavour to do them proactively and to eliminate risks before they occur, in many of these cases we may be -- we can be completing work based on the leading indicators, which would be the vegetative condition, as opposed to just lagging indicators, and we're completing this work to avoid future outages that we do think will occur, as opposed to just finding areas that have had outages and only focusing on those areas to reduce the risk in that area.

So focusing on the vegetative condition allows us to be very confident that we are reducing the risk of tree contacts. It gives us confidence that we're focusing on the right area, because we know the vegetative condition of our entire system, as opposed to simply relying on lagging indicators such as past outage data.

Q. So in terms of measuring the effectiveness, then, are you suggesting that the measurement be changing condition rating?

A. (Beaton) Yes, that's correct. That's our primary measure.

Q. So there's no cost component related to that measurement of effectiveness; it's just a change in the rating of a particular feeder? A feeder goes from four to three -- I can't remember which way is good and which way is bad, but let's say the four is bad and three is better, it goes from four to three, that's how you're going to measure the effectiveness without any consideration of cost in terms of measuring that?

A. (Beaton) Certainly we have consideration of cost. We (inaudible due to mumbling) this program in the best, most cost-effective way possible.

We currently don't have a metric on a dollar per condition score change. Generally, we complete

-- there'd be a condition score basically on a span-by-span, although we report on it at the feeder level, but we manage our program at the span level, so the area between the two poles, when we complete our vegetation program. Each one of those would have its own score. And any situation where we complete work such as this, that's dropping the vegetative condition score to whatever is today, whether that be a three, four, or five, to a one, which is the best -- which is the most optimal condition.

Q. Okay. I understand that. But I suppose from the Board's perspective and the customer's perspective, you know, a big thing is cost, and a big thing is outages, and, you know, the condition of a line can change -- the condition already can change, but is it at any cost?

In addition, even if the condition rating changes, I think based on some of the numbers I showed earlier it doesn't necessarily translate, at least over the past number of years, into reduced customer outages and customer hours interruption, at least under those years without MEDs and EEDs. So, you know, to measure effectiveness just by changing condition rating, at least in my opinion, doesn't seem to consider outages nor costs.

A. (MacIntosh) Mr. Murphy, I can speak to this. I think if we go back to the conversation yesterday -- I agree with your point that condition rating alone would not be adequate, but once we look at vegetation condition, and then you also have to look at the consequence of vegetation on that line and that segment, so that's the consequence. Those two together identify risk. So condition and consequence together determine risk. Those are both determinative.

[11:50:19] But as we talked about yesterday, is after we've identified the vegetation risks on the system, and then looking at the criticality of where those vegetation risks are, we get a risk score, or a risk rating, and then we need to apply -- to your point --

what's the best reliability cost efficiency to deal with that risk? And that's where we look at mitigation measures to determine what's most cost-effective for our customers.

So I agree with your point that condition alone would not give you the exact monetary value of that reduction in risk.

Q. How do you factor customer interruptions and customers hours of interruption into that analysis?

A. (MacIntosh) So each feeder would have a criteria for criticality. So if you had an outage on this particular feeder here's how many customers would be impacted. So that's based on the criteria for criticality of that asset. We do it for all of our assets, we would have a criticality rating. So that's how we get at the impact -- potential impact of an outage.

Q. Okay. Thank you.

I think Ms. Powell touched on this a

little bit yesterday. Nova Scotia Power's target for SAIDI for its Five-Year Reliability Plan is 2.05; is that correct? Or SAIFI -- sorry -- is 2.05?

A. (MacMullin) That's correct.

Q. And that's a target for 2029; correct?

A. (MacMullin) That's correct.

Q. And that standard's been in place, I think, since 2017; correct?

A. (MacMullin) So the goal of the program, in terms of defining it as a target, so our target every single year, our goal every single year is to meet the established performance standards with the safety of 2.05. The goal of the Five-Year Reliability Plan is to put the company in a position, again within the context of the changing climate, that we're able to consistently meet that. And so the intent of these investments is that by the end of 2029 that we have completed investments such that we are able to consistently meet that within the operating conditions and the climate in which the company's operating.

Q. Okay. And I think to Nova Scotia Power's credit in response to IR-186 showing your safety results for 2024 and 2025 both exceeded the standard. I think in 2024 it was 1.97 and 2025 it was 1.57. So both bested the target of 2.05; is that correct?

A. (MacMullin) That's correct.

Q. So in light of that, I guess there's two ways to look at it I suppose, why not change -- you've met the target in those two recent years, why not change your target? I know what the performance standards say; they may change, but at least for the past two years you've met that standard. So I suppose there's two options. You could try to achieve -- change your target to meet those numbers, or increase your spending, perhaps, to stay at the 2.05 target. Just can you give me your comments on that?

A. (MacMullin) So a couple of

things. Again, so as you mentioned, the performance standards do have an inherent ratcheting baked into them, so they're -- as the performance of the system improves the target would move with it. So that is already baked into the way in which we are measured, held accountable.

Again, it's when we're looking at SAIDI and SAIFI they are connected; they don't move independently of each other. And so the investments on our system that we're recommending are meant to -- again, to reduce both the duration and the frequency. And so we have seen -- with the conditions that we experienced in 2025, we have seen that the system met the SAIFI results.

Absolutely when we look at the variability that is inherent in the system and with the weather that we can be exposed to, we do see that there is some potential there for things to change as the system responds to those conditions. So we would be -- it would be our recommendation, as outlined in the plan, that continued investment, as defined here, is the numbers that is needed, and these are the programs that should be targeted so that by 2029 -- and with, I might add, incremental improvement each year, certainly not -- you know, there won't be a step change at the end. There will be a step change every single time one of these projects is completed, every single time a span is cleared of trees we need to realize that benefit in real time.

And so to try to separate functionally that SAIFI has had -- has reached, in 2025, a value where we may be potentially theoretically comfortable with sitting and then disconnecting that from SAIDI, would be incorrect.

Q. Okay. Understood.

Let me ask you a question on SAIDI, then. And again, Ms. Powell referenced this yesterday.

I think the new target, 20 percent reduction in -- I forget the number, but 5.1 something -- 20 percent reduction, that takes you down to 4.08. That's your target for 2029, I believe. You may have said 4.1, but we won't -- I don't think we'll quibble over the difference there.

So your target is 4.08 by 2029. The current standard is 4.29. The performance standard is 4.29. So when you look at those two numbers in terms of minutes of improvement in SAIDI, that's -- by my calculations, it's a 12.6-minute improvement in SAIDI from the current target by 2029. And from 2021 to 2025, again, Nova Scotia Power spent 97 million on D010 and new right-of-way capital spending, and there's certainly lots more to be spent from '25 to '29.

So how do you justify that amount of spending for a 12-minute improvement of SAIDI from the target?

A. (MacMullin) So first of all, so again -- when we look at, again, the commitments of the plan, it is an hour reduction, right. So the overall goal of the plan is that, by the end of 2029, that, on average, customers are experiencing an hour of reduction in SAIDI, which is significant. It’s 20 percent.

The intent here is, again, to be consistently meeting performance standards. So you know, the goal that we’re going for is slightly under that because, again, there is variability in terms of the response of the system. If we aimed to be right at 4.29, we know that sometimes we would be potentially over that, which would not be a successful intent and implementation of the program.

But again, within that context, so absolutely the plan is being carefully monitored and evaluated each year. If this is more -- if this overshoots, so if by the end of year three we find that the system is performing and meeting these standards at that point, we will absolutely look at revising what ’28 and ’29 look like.

So right now, with the information I have in front of me, with my understanding of the system and how it responds to these investments, this is the plan that I feel is going to get us there within that, absolutely looking at -- in terms of the real actual result -- response of the system to those investments and what are we actually getting, in terms of duration.

So we're providing that transparency in terms of how we're updating this, and within the performance standards venue as well in terms of looking at the performance of the system and then committed absolutely to looking at, you know, in future years if that should, in fact, be revisited.

[12:00:10] **Q.** When you say an hour, an hour SAIDI, that's from Nova Scotia Power's current level of SAIDI performance; correct?

It's not from the -- the target is 4.29, I think, right now, and Nova Scotia Power is above that, right? So when you say an hour improvement, it's from current SAIDI performance, which doesn't meet that standard.

A. (MacMullin) It -- yeah, the

numbers there would have been based on, I believe, an hour based on the previous five-year average, which was 5.1, to get us down to the 4.29.

Q. And I recognize that an hour is a pretty good savings but, you know, Nova Scotia Power, I think, in seven of the past nine years hasn't met its SAIDI target. And like I said, it's spent 97 million from '21 to '25 on D010 and right-of-way widening. That doesn't include operating costs related to vegetation management. There's going to be lots more money spent from now until 2029.

Again, recognizing an hour is a good improvement, but how do you know you're getting your bang for that buck?

A. (MacMullin) So I would ask that we consider the evidence as has been presented that we are demonstrating that we are targeting those investment dollars, those vegetation dollars where we're widening or establishing a right-of-way on the parts of the system that have demonstrated that, in terms of the condition that’s being reported -- so we’re using satellite imagery to have even more accurate indications of the -- of where the trees are in proximity to the line, so we’re considering that.

We are absolutely looking at the outage performance. We’re looking at those lagging indicators. But we’re not stopping there.

And to my colleague, Mr. MacIntosh’s, earlier testimony, we’re then further looking at it in terms of what are the leading indicators, so what is the impact of this particular line if there’s an outage and looking at the criticality of that line, how does that factor into it.

So all of those things are a very sophisticated way and robust way of saying where should we be this year, what span should we be targeting.

And then again, there has been careful reflection back in terms of how we’re executing that program in the last couple years to say maybe we should be doing this a little differently. So is there a way -- we're seeing more impact. We're getting -- when we can negotiate with customers, we are getting cleared right-of-ways, but we're seeing impacts from outside the right-of-way, so can we do something differently, and does that make sense. And so we've implemented them. We're seeing -- we're absolutely seeing benefits from that.

And so all of those things together, those are the things that are driving the lists that you're getting. When you're seeing those lists of where are we going this year for D010, for new right-of-ways, that's where those lists are coming from.

And again, I would suggest to you that we are absolutely seeing the system is responding positively. We are seeing a reduction despite the fact that the winds have almost doubled decade over decade. We are still seeing an improvement and that will -- year over year, as we complete more of this vegetation and as we clear more trees away from the line, that is going to build year upon year, and we will see those improvements and ---

Q. Okay. Thank you.

One last question on this topic. You recognize that there’s a new performance standards review under way. If the performance targets for SAIDI and SAIFI change as part of that review, is it your intention to change the targets for the Five-Year Reliability Plan to match those?

A. (MacMullin) Absolutely the plan would be updated. So if we’re in a situation where as a result of the Five-Year Reliability -- pardon me, the performance standards review that there is a decision to change performance standards, then this would change to reflect that.

Q. So if the targets would change -- if the targets are lowered, let's say that the target for SAIDI is 2.05, say it goes to 2 and the SAIDI target goes down. So you'll adjust those targets accordingly in your Five-Year Reliability Plan. Does that suggest your spending's going to go up as well?

A. (MacMullin) So the core of these programs -- again, let me answer it -- let me answer your question this way.

We know that the things that we're investing in when we're looking at storm hardening veg, storm hardening target devices and modernizing the grid, those are core foundational things that are going to get us in the direction that we want to move.

So the question is, if the established targets become more stringent for performance standards, and that is the direction of this Board, then we will go back and we will look at those core foundational programs and then we will put forward to the Board what needs to change, which could absolutely include -- if they became more stringent it could include an increased recommended spending in some of these areas.

Q. Okay. Thank you.

Okay. Just a few more questions. I think we'll be done shortly, at least from my end.

I have some questions, probably again for you, Ms. Drover, on hydro and I maybe have a couple on Mersey as well.

In last year's ACE Plan proceeding, in response to the Board IR-13(c) -- I could get Rob to call this up, but I'll hold off for a second -- Nova Scotia Power identified the estimated costs for the Wreck Cove T-1 Tunnel Remediation Project would be roughly $40.7 million from ‘25 to ‘28. This was in the five-year projections for hydro spending.

And in this year's ACE Plan, in response to Board IR-17 -- I can get Rob to call it up, if you want -- but the projected spending for that project has now dropped significantly to $17.2 million.

I'm just wondering if you can identify why that's changed so much.

A. (MacIntosh) Mr. Murphy, we continue to monitor the condition of that piece of the tunnel at Wreck Cove. A high-level response would just be based on our understanding of the condition and the updated scope of work for that project.

Q. Do you know when you expect to submit that project for approval?

A. (MacIntosh) One moment, please.

Our latest information, it'll be 2028, probably at the earliest.

Q. Okay, thank you.

There's a project within that five-year-cost projection, a projection for hydro for the Annapolis sluice gates and check refurbishment of about 5.6 million, and my question is if that Annapolis Tidal Station is decommissioned, is that project still required?

A. (Drover) Yes, that project would still be required. The decommissioning is associated with the powerhouse and the generating assets. And that project is for work on the dam and the continued safe, reliable operation of the dam.

Q. Okay. If it was not to be decommissioned, it would still be required?

A. (Drover) If it was not to be decommissioned it would also still be required.

Q. Okay, thank you.

Another question on Wreck Cove, in last year's ACE Plan proceeding, in that same five-year projection, there was a project for Wreck Cove Tunnel T-2 remediation future phase for about $28 million, and it doesn't appear to be included in this year's five-year projection. Is there any particular reason why?

A. (MacIntosh) A similar response, Mr. Murphy.

We have been -- updated our strategy to assess the condition and we're doing more inspections through Remote Operation Vehicles in those tunnels. And that's just reflective of our latest understanding of the condition of T-2 when that major investment refurbishment would be required.

[12:10:10] **Q.** Okay, thank you.

Just a couple of short questions on the Mersey Hydro Project.

One of the Board IRs asked, I think, Nova Scotia Power to confirm that the partial decommissioning costs were more -- the estimated partial decommissioning costs were more than the full decommissioning costs. And Nova Scotia Power provided an answer, and I think it was basically -- tell me if I'm correct; it was basically because the water retaining structures would still, in a partial decommissioning option, would still require work. Correct?

A. (Drover) It is correct that the partial decommissioning would be relative to the powerhouses and the generating structures, and the dams would still require refurbishment.

However, to your question regarding

partial decommissioning versus full decommissioning, the estimates for those two scenarios are different classes of estimates, and also the full decommissioning does not incorporate costs associated with the socioeconomic considerations, as well as internal costs and AO and AFUDC costs.

Q. Okay. So I guess if we assume for the moment that partial decommissioning would cost more than full decommissioning, my question was going to be why would it even be presented as an option? But I suppose, based on what you just said, correct me if I'm wrong, that the considerations of those socioeconomic issues; is that correct?

A. (Drover) Yes, that is correct.

Q. Okay. And back to your other point about how the costs -- they weren't developed to the same level, partial decommissioning versus full decommissioning, and that it's difficult to compare the two based on those different levels of accuracy, if you will. When the full -- when the Application comes before the Board for the Tusket ATL for the dam refurbishment option, presumably Nova Scotia Power is going to compare the cost of the refurbishment project to partial decommissioning and the full decommissioning.

At that particular time, are the costs of partial decommissioning and full decommissioning going to be developed to the same level as the refurbishment option? And, if they're not, based on what you just said, how will the Board be able to review the options and give it a fair comparison?

(SHORT PAUSE)

MS. DROVER: You are correct in your assumption that when the project for Tusket refurbishment comes before the Board, it will include an analysis of costs in all three scenarios: Full decommissioning, partial decommissioning, as well as refurbishment. And if, through the analysis, full decommissioning is in the best value for customers, there would be a significant engagement and stakeholder process to really understand the socioeconomic impacts and costs associated with that decommissioning. There would be a significant impact on the residents and properties along that hydro system, and the evaluation of that would need to be a major engagement process to understand those impacts.

BY THE CHAIR:

Q. I understand that, but I'm not sure I got an answer to my question.

I was asking if the costs for the three different options are going to be developed at the same level. I think you recognized in the IR response, and you recognized a little bit earlier that you can't compare the options from a cost perspective if they're not developed at the same level.

A. (Drover) In the case of the Mersey, right now full decommissioning is shown to be a lesser cost than partial decommissioning.

In the case of Tusket, depending on

how the initial assessment comes out, if full decommissioning without the socioeconomic costs lands at the highest cost option, then we would need to determine whether we would need to go any farther to fully understand the socioeconomic costs at that time or not.

If in the case that the full decommissioning costs were less than either partial decommissioning or refurbishment, then a much more extensive exercise would need to continue in order to understand the extent of those costs.

Q. When you do that initial assessment you're going to compare the -- is your mic on?

A. (Drover) Mine is.

Q. Is my mic on? Does it work?

Okay. When you do that initial assessment, you're going to compare the refurbishment costs which have, you know, been developed pretty well. I don't know what the class level might be. Maybe it's a two. I'm not sure.

The cost estimates for decommissioning, at this point anyway, from the ones I've seen, are at a Class 5. So in terms of accuracy estimates, there's quite a bit of difference in the range -- expected range of accuracy between those two levels of estimate.

So if you're telling me that initial assessment is going to be based on that kind of analysis, it suggests that it's still not a fair comparison.

A. (Drover) I think we would have to look at the sensitivity of the range of that class of estimate and understand how that range is associated or relative to the other two options. There are decommissioning costs that are quite well developed with a low range of uncertainty, and there are other decommissioning costs that have a higher range of uncertainly, for example, archeology, and also the socioeconomic impacts.

However, if that Class 5 estimate with

the associated range is so significant that the range falls outside of the range of the higher accuracy estimates of partial decommissioning or of redevelopment, then I believe you could compare those options.

MEMBER MURPHY: Okay. Thank you.

Those are all my questions, Mr. Chair.

THE CHAIR: Thank you, Mr. Murphy.

And actually just in time because it appears your camera has frozen, but we'll leave that for now.

I think the best course of action is to move on at this stage to Ms. Nicholson and see what her questions and then we'll see where we land after that as to where we go from there.

[12:20:07] So Ms. Nicholson, do you have any questions for the panel?

MEMBER NICHOLSON: I think I was hearing your voice. Most of my questions have been asked by Mr. Murphy so I don't think anyone will mind if I skip at this point.

THE CHAIR: That's fine, Ms. Nicholson.

I have some questions. I can probably be done before 1:00. So would it be preference -- I think we should probably just carry on, and I will proceed with my questions unless somebody actually does need a quick break right now and we can take a quick break.

MS. POWER: Mr. Chair, could I have a very quick break?

THE CHAIR: Okay. Let's do 10. Might as well do 10 because it's -- so let's come back at 12:30.

Keeping in mind, everyone, that, you know, there's still going to be re-direct and then there's going to be those of Mr. Wilson. We could break now if people wanted to, but it's completely up to the ---

MS. POWER: Mr. Chair, I think it makes sense to break for lunch now and then come back, finish your questions and move on with Mr. Wilson, if that's okay with everyone.

THE CHAIR: So break now and then -- yeah, let's do that. Let's do that.

So let's come back at 1:30.

--- Upon recessing at 12:21 p.m.

--- Upon resuming at 1:30 p.m.

DAVID ARTHUR PICKLES, Resumed:

TREVOR ARCHIE BEATON, Resumed:

LYNNE ANNE DROVER, Resumed:

JONATHAN ROSS CLARK MacINTOSH, Resumed:

CHARLENE DEEANNE (Sp?) MacMULLIN, Resumed:

ERIN CHRISTINE PEACHEY, Resumed:

THE CHAIR: Good afternoon, everyone. We'll resume, and we'll resume with my questioning.

QUESTIONS FROM THE CHAIR

Q. So my first look will be at Exhibit N-6, and PDF 81. And it's about the D055 Planned Replacement of Deteriorated Equipment Routine. And we discussed -- this was discussed to some extent yesterday, with respect to how the routine is reviewed and how the cost is worked up.

But my first question relates, and I know there was a discussion about the 9 million -- $9.3 million and the actual spend of $21.9 million, but that you arrive at a $15 million adjustment for this year. And so my first question is related to this IR-38(a), which indicates that the -- this 15 million is still an increase from forecast -- over the forecast for 20 -- for the previous year of 9.3. And so it says:

> The increase in forecast spend for 2026 is primarily driven by incremental investment in system reliability initiatives. Spending within this routine is primarily allocated to targeted equipment replacement, including pole upgrades to larger, stronger poles. This increase in spending is aligned with the Five-Year Reliability Plan and is driven

by risk-based [assessment].

And you discussed yesterday the process of risk-based assessment and how that's worked up. My one clarification I was trying to -- wanted to ask was how -- because I'm assuming for the risk-based assessment, there is some field information that is available and that has been used to make the assessments. How does that information get transferred from the field to the people making the investment decisions?

A. (MacMullin) Can I get you just to clarify the question just briefly for me?

Q. Sure. My understanding from the discussion yesterday was that when you're doing the risk-based assessment, there is -- I mean, there are various components that go into that, which presumably some would be age and various factors, but is there not also a field-driven observation type of information that would go into that routine?

A. (MacMullin) Yes, that's correct.

So we have a feeder inspection program ---

Q. Yes.

A. (MacMullin) --- on the distribution feeders and the transmission feeders, and so that is, like, human beings with their eyes and their expertise, and they assess the condition and they record it and then that is directly fed into the assessment ---

Q. Right.

A. (MacMullin) --- of condition.

Q. And when is the plan formed? For 2026, when did you develop the plan for 2026?

A. (MacMullin) So it would be developed in the preceding months of 2025. So we try to have -- we try to make sure that we're reacting the most recent data.

Q. Right.

A. (MacMullin) Yes.

Q. Okay. The discussion yesterday also talked about the estimate is prepared for the ACE

Plan, and it talked about the risk-based assessment, that process that we just described as being part of the component, but there's also a historical component to how you derive that estimate; is that correct?

A. (MacMullin) Absolutely.

Q. And why would there be a historical component if you're trying to look at the asset condition or what the risk is for the current -- for the assets for the coming year, how does the historical information assist with that?

A. (MacMullin) So in a couple of ways. So certainly it would never be the only factor that we would consider, but it is a factor. It does have some information, in terms of how are the assets, those particular assets, performing.

You know, as a specific example, if we saw historically that we had some tie wrap issues, then that would -- on a historical basis, then that would give me an indication that perhaps going forward that, you know, perhaps the -- perhaps the coastal nature or what have you, or the winds, you know, maybe that would be an opportunity to move to a clamp-top insulator, that tie wraps aren't the right choice here. Like, so looking historically how has the feeder performed informs the future.

It's absolutely, though, in terms of the lived experience of the customer from that feeder. If historically there has been more outages, so if the reliability is not where we want it to be on that feeder, then that would be part of how work is considered and prioritized. So certainly part of it is safety, part of it is condition, part of it is historical on that -- eyes on the ground, what did we actually see last year, all of that.

Q. I thought perhaps the historical version was the historical spend on that routine and whether that factored into the estimate. And if it did, what relevance would it have, what the historical spend would have on the future spend?

(SHORT PAUSE)

BY THE CHAIR:

Q. And I may have misunderstood the response, so don't take that as how the thing is -- how it's actually prepared, but that's what I understood from the response.

A. (Beaton) So in this routine, there's a planned portion and then a reactive portion, which we call bin work. And in this routine, we use the historical average spend for the bin work portion, but then there's detailed -- I don't have the page number in front of me -- within the routine backup.

Right, on page 74 in Exhibit N-1, that's in the confidential version, mind you, so it might be slightly amended, there's a bin work portion that we apply the historical rate too. And then there's planned work that we would include based on all the evidence that Ms. MacMullin would have just explained that drives those decisions.

Q. Okay, okay. Stronger poles.

THE CHAIR: Can you just go back to the IR response? Just scroll back up to (a).

BY THE CHAIR:

Q. It discusses stronger poles, but is stronger poles really a key driver of the increase in costs?

A. (MacMullin) So the primary driver of the increase in spend is the net increase in work that includes things like a changing to stronger poles. There definitely is an incremental cost increase to move to the stronger pole class, but to your point, the larger driver of the increase in cost in the routine is the overall increase in the number of units of work that are being completed.

Q. Okay. And if I put it to you that this routine is becoming more related to upgrading the system with a more robust infrastructure, rather than planned replacements of aging or deteriorated assets, what would you say to that?

A. (MacMullin) I would say that this routine is absolutely about replacement of deteriorated assets, so certainly it makes sense and it is prudent that when we're replacing those assets that we are replacing them with, you know, what's available today.

So the -- you know, so for instance, if we're replacing a pole, we're replacing it with what we know to be the right pole for the system today, which is an upgraded standard. If we're replacing an insulator and we're -- again, we're reflecting and learning how we're going to replace that insulator maybe with a clamp-top as opposed to a tie wrap.

[1:39:47] **Q.** And that would apply to both planned and -- I guess they're all planned, but both reactive and historical types of -- or bin work, as it's described.

A. (MacMullin) That's correct.

Q. If we can -- is there sort of a reflexivity between D005, which is the planned, and the -- D055 which is planned and D005, which is the unplanned? Is there reflexivity between the two? In other words, if we do more planned replacements would you expect the unplanned ones to go down?

A. (MacMullin) Yeah. Over the long term, absolutely. So one of the outcomes that we would expect to see longer term of this program is we would expect to see D005 reduce.

Q. And would there be actually some -- in D005, I'm thinking more, like, overtime labour and that kind of stuff where the unplanned ones which replace the same assets might generate more costs -- operational costs as well?

A. (MacMullin) Yes, you're right. So the reactive nature of the response to much of the work in D005 would drive things like overtime and after-hours responses, so those types of reductions would be inherent in that. So as we -- as we move away from more reactive events, over time that would decrease.

Q. Okay. The same exhibit, I'm going to turn to D005, which I think the place to start, it's response to Board IR-31(a) and it's the top of PDF page 77.

<u>THE CHAIR:</u> And here, we're talking about the -- if you can just go scroll just down a bit just to go to the -- what precedes that table.

Sorry. The other way. Okay. Hold there.

So it's talking about the outage events totaled as failed event by asset category.

So if you can just go down to the table now again, Rob.

<u>BY THE CHAIR:</u>

Q. Okay. So when I look at these as broken down here, it looks like just over 82 percent is -- 82 percent of the outages are driven by failures to fuses, conductors, transformers, connections and service assets. Does that seem about right to you?

I mean, I just did the math by adding it all up and dividing it by -- numerator by denominator.

A. (MacMullin) I trust your math.

Q. Okay. And what asset category are poles classified? Is that structure?

A. (MacMullin) That's correct.

Q. Okay. What was striking about this IR response is that there is a decrease in outages -- total outages from 2022 to 2025 associated with the routine. And I know there's some storm years in there and factors into the situation. But the point is the numbers -- number of events went down but the annual cost in part -- seems to be going up.

THE CHAIR: I'm interested in part (b) of the response, if you just scroll down a little bit, for these particular assets.

No. Just previous to that. Keep

going. Right there, (b). Went by it again.

Keep going. Next one. This one, this table.

BY THE CHAIR:

Q. It just seems like the -- especially there seems to be a cost that's going up, the actuals. Like, we started around 8,900. That's person days. The costs are in the next one down from, let's say, 1915 in 2022 to 2455 in 2025.

And I'm just wondering; is what's happening here is the actual cost per unit is going up as opposed to the number of events you have to respond to?

Because you're going from about $17 million to $21.2 million or 25.1, the actual, but the events have gone down?

A. (MacMullin) Yeah, there's several factors in that.

So absolutely, you know, the associated materials costs and the inflationary impacts of that are reflected in this routine. It's also -- there is also variability in terms of the costs associated with certain types of work. So not every pole replacement, not every replacement of a -- of a span of conductor would cost necessarily the same because of things -- to your point, whether or not it was done on overtime. You know, there's all sorts of mitigating factors that can lead to a particular reactive work to, you know, have a different variable in terms of the costs. So that would be reflected in this.

One of the things that we are targeting in this program is we're really going after the things that -- you know, that will incrementally move the needle. You know, we're digging hard. That's a big challenge of the team and intent and focus of having a dedicated reliability team.

And so when we're looking at these things, you know, we are looking at it with a lens in terms of, you know, if there's one insulator that's failed, we're looking very closely at the ones around, right? So like, you know, is there more to learn there? Is this the right time to get those as well? And you know, that is reflected in here.

So again, just a real reliability lens in terms of how is this work being done.

Q. And aside -- I mean, aside from the actual cost of the equipment, materials and labour, there -- the location, what locations you're working in might impact on that as well, as far as how long it takes to do these projects?

A. (MacMullin) Yes, that's correct.

Q. Could we just hold on for one second?

(SHORT PAUSE)

THE CHAIR: Never mind. My apologies.

BY THE CHAIR:

Q. Okay. I'm going to turn to another topic, and it has to do with the completed transmission line replacement and upgrade projects. And the Board had given a directive that there be a list of the transmission line replacements and upgrade projects that have been approved since 2021 ACE Plan, and we received that. That's Appendix I to N-1. And it shows the associated costs for each line.

And you also provided the original commission dates for the various lines, the number of structures refurbished, the average structures per kilometre and the estimated length in kilometres for each replacement project.

So I can do the basic math and it tells me how much -- how much the cost per km is and how much the cost per structure is, but that doesn't help, necessarily, for me to determine the reasonableness of those costs if there's no benchmark to apply it against.

And so I'm wondering if there is a benchmark for this type of work that I can apply -- that I can look at the cost per kilometre and tell whether or not that’s a reasonable cost.

A. (Beaton) So when completing this work under (inaudible due to mumbling) system, determining a cost per kilometre or using it as a benchmark, I should say, is quite difficult. The level of -- or the type of work varies from structure, obviously. In many cases, as part of these programs, we’re replacing the entire structure. In many cases, we’re not; we’re just replacing components on that structure.

The number of structures, the distance between each structure would obviously play a big factor in how much if you were to use a per kilometer rate so that would be a really difficult benchmark to use when comparing one project to the other.

I think if we were to pursue a benchmark, you’d want to look at it from a unit perspective what the cost of a full structure -- if you’re completing nine full structure replacements versus -- in one project versus six in the other, does that unit cost stay similar. It's always going to vary due to a multitude of variables. But a simple benchmark on a project like this that is always going to be replacing different levels and different types of assets or components in that asset, it does get difficult to compare from one project to the other.

[1:50:09] **Q.** You know, we do assess appeals -- or I do -- not all Members here do -- and we have -- when we're looking at replacement costs, we're looking at the swift standard modeling of -- you know, every station provides basically a benchmark for almost every component of a building. That doesn't exist in the transmission line field?

A. (Beaton) It's not one we use today. Yeah. And sitting here, I would struggle to determine a really good comparable from one to the other that would be easily used or easily portrayed that would show some value in comparison.

I guess it's important to providing

comfort that this work is all done through a unit process that will be procured through our traditional line service agreement, so the costs generally scale quite consistently when you're increasing or decreasing the level or intensity of the work from a unit structure or asset component perspective.

But yeah, today I wouldn't have a good proxy to use for a comparable from one project to the other.

Q. Yeah. And I come across -- I just thought I'd ask while we're here.

Okay. As far as the cycle, once this process has been completed -- because we're going back a number of years now, what's the cycle for going back to these lines to look at them again?

A. (Beaton) So it wouldn't be a set cycle, by any stretch. This is all based on our newer components, our transmission line inspection program, the LIDAR data that we get -- that we fly on a certain cycle basis that would tell us the condition of each one of these asset components on -- across these structures. So when we go back would be only determined on the condition as found through these inspection processes.

Generally it’s certainly a long period of time. I think in most cases you’re in probably 25 to 40 years that you’d be expecting to get out of these investments. So there wouldn’t be a set cycle. It would continue to be based solely on condition.

Q. Okay. My next question relates to -- we’ll just go to Exhibit N-6, PDF 148. It’s the response to Board IR-59.

And again, this is a project for subsequent submittal, and I don’t go into the details of this project. In fact, I thought I had perhaps missed it when I saw certain submissions about this project, but it is an item.

And when I looked at the 2025 ACE Plan filing, it showed this project having a risk rating of 25.

And would I be right that 25 is pretty well the highest risk rating you're going to have on some of these projects?

A. (Beaton) It is, yes.

Q. Okay. And this is -- just for the record, it's IT CI -- customer information system replacement, and it's included as a subsequent submittal item for the 2026 ACE Plan.

Is the project still on track for submittal in 2026?

A. (Beaton) As of now, yes. Our current intention is that it will get filed in some point in Q4 of this year.

Q. Right.

THE CHAIR: Because there was -- in the answer to the IR -- if you can just scroll down, Rob, to the next page -- it talks about the various risks that might cause a delay.

BY THE CHAIR:

Q. And I was just wondering if those were -- you know, had already been -- are being addressed or will be addressed to bring this product forward. And the reason for the question is completely different than submissions that were made. It has to do with the risk to the system if this is not done.

And I'm just wondering what that risk is if it's not done in a relatively short order.

A. (Beaton) So we certainly continue to monitor that. Our current expectation is that it will get filed later in the year. But as with all our projects, we -- if there is risk present that needs to be mitigated, such as the case is here, we often will implement a non-capital solution to do it. So whether that's changes in how we use the system or certain controls we put around it, we continue to be very confident we can manage the risks around this system until we complete the replacement.

Q. Has the cyber incident impacted

on the ability to do the groundwork to get this project filed?

A. (Beaton) It certainly was one of the causes for us deferring the work in this project, the development work. It was originally planned to be completed in 2025 ahead of a late 2025 filing. We prioritized the resources that were going to work on that towards the cyber project -- or the cyber initiative.

So yes, it was certainly a cause of the deferral. But again, going back to my first point, we've been able to manage the risks associated with it to keep the system operational until we complete this replacement.

Q. Okay. My next question relates to -- it's basically the project -- Exhibit N-6, PDF page 605, and it's Board IR-146. But it relates to the intelligent asset data capture and integration platform.

I think this may be one of the first projects that's been filed that's over $1 million but that has significant third-party funding that brings it well below the $1 million threshold. So it's how this was all developed last year.

So the project total estimate cost is $10.3 million, but when you deduct government funding the ratepayer cost is only $268 million, roughly. But -- and also in this response to IR-146(a), which I'll just kind of scroll a little bit to the response, it talks about there being -- there is currently no forecasted additional operating or maintenance expense costs.

My question was, there was a reference to 100 end user licences. Are end user licences part of the $10 million or are those purchased separately?

A. (Beaton) They're part of the project costs we put forward.

Q. Okay. And do they have a term? In other words, the question is if they're a renewal and therefore a cost associated to renew them?

A. (Beaton) No, those licences are

fixed for the deployment of technology so there's no interim.

Q. Okay. Once you have this technology in place and you're using it as anticipated, and you've described the various ways it can be used, do you know the lifecycle? In other words, how long will this technology be current and will it become obsolete so fast that you're going to replace it fairly soon?

A. (Beaton) So the currentness of them will likely vary on an asset basis. Certainly after -- if we're looking at a photo that's five years old, we would have to confirm that it's still in the current state. So it will have an -- it won't be accurate for an indefinite period of time. It's going to be recognized that at some point in time if we want to continue having access to this data we would have to look at it again to see if it's worth the investment to update all of that information.

But obviously, we're confident with

the significant federal funding that we were able to procure for this to get this level of information for what was a relatively low capital cost. We think there's great value in that.

Q. Okay. I'm going to turn to the Path to 2030. I know it's already been discussed. I just have a few questions on it.

THE CHAIR: So we'll go, Rob, to N-1, Appendix F, Figure 1 that we just had. That's the one.

BY THE CHAIR:

Q. We've already discussed your ECEI synchronous condensers and you've described various aspects of that.

My question is simply, leaving aside the correspondence that we've received, how close to a submission was that project or is that project at this stage?

A. (Beaton) Yeah. As I mentioned yesterday, we're in the midst of commercial negotiations with various proponents, so I would expect that the filing would happen in Q3, into Q4 potentially. So our plan was to file in 2026.

Q. And I just want to make sure I heard the answer correctly. There was a question about the amount of money that had already been spent on the capital project, and I thought you said it was around $1 million. Is that correct?

[2:00:00] **A.** (Beaton) That's correct.

Q. Okay. All my other questions were already asked yesterday on that particular project.

So turning to Figure 1, if I look through the various, I'll call them, generation or energy sources that are listed there, it seems to me that the only ones that are -- leaving aside, you know -- but the only ones that are listed on this page are the two conversion -- coal plant conversion plans that are left with Nova Scotia Power. Is that correct?

A. (Peachey) That's correct.

Q. Okay. And you've provided updates on these two projects in the appendix and in IR responses.

My question, and it's the same question I've asked in different forums in a number of ACE Plans, is if -- because -- am I right, am I not, that these other procurements, these other wind programs, these other sources of energy have to be in place before you can actually do the coal conversion safely and reliably so that you meet all the reliability standards, the NERC standards, those types of things? Am I correct about that?

A. (Pickles) It's a combined effort, absolutely. Is your question specific to being off coal or being 80 percent?

Q. Well, it's both because these are coal conversion projects and, if they're started, they have to be -- under the current legislation, they have to be completed by end of 2030. And so my question is, if all these -- if other projects are delayed, because a lot of these projects have -- when you look at being able to retail wind, when you look at the future procurement, when you look at community solar, commercial net metering, you have future procurement, even the Green Choice Program says that 2028 date, but I have not heard yet about the new procurement and how that's going.

A. (Pickles) Right.

Q. You're getting close to the 2030 period, so if any -- if some of these projects don't reach operation by the 2029 period, can you still do the coal conversions? In other words, safely do the coal conversions and still have what you need for power?

A. (Pickles) Yeah. So you know, we certainly want to be ready to be able to be off coal by 2030, which at this point we'll see the full conversion of Lingan to oil and Point Tupper to natural gas. My intention would be that we would still have the ability to burn coal if we were so allowed to do so.

You know, our primary concern and focus is to ensure there's adequate capacity on the system. As the utility, we want to make sure the lights stay on. So we would certainly not retire a unit or inappropriately transfer to another fuel if we couldn't meet our capacity needs.

Q. Sure. But I mean, under the current legislative scheme, can you do that without changing the scheme, the legislation scheme, and still stay on coal after 2030?

A. (Pickles) No, we could not without regulation change, but certainly having the ability to fuel switch, we will be ready by 2030.

Q. Sure.

A. (Pickles) Yes.

Q. But if -- yeah. That's not so much on your ability to fuel switch. My focus is on if -- well, I suppose if you could fuel switch that would help at that stage, as long as the other projects were not

A. (Pickles) Right.

Q. --- in place. Okay.

A. (Pickles) Yeah.

Q. My real question is, there's a considerable cost to doing the two coal conversions, and as you know, I suspect, following the news, there have been a lot of changes in the carbon world since the -- a new Federal Government has been in place. And like, I guess, has there been any discussions about -- or anything that's taken place that would lead you to believe that the 2030 coal -- being off coal by 2030 is going to change?

A. (Pickles) We haven't been in direct conversations with the Federal Government, but to your point we know provinces like Alberta and Saskatchewan are in active conversations around extending coal use beyond 2030. I believe the Federal Government, their intention is to apply a more global approach, so there could be changes coming, but that's really outside of my scope.

Q. Yeah. It's speculative at this point.

A. (Pickles) Absolutely. Absolutely.

Q. But, I mean, it would be a difficult situation if you did a coal conversion ---

A. (Pickles) Right.

Q. --- and you didn't need it, is what I'm trying to get at.

A. (Pickles) We -- and that's why we slowed down and why we delayed, to some extent. We made sure we will have adequate time to implement the technology needed to make the change in time for 2030, but certainly don't want to spend capital and have it stranded.

Q. Right. You discussed yesterday and answered some questions the collaboration is taking place in a team with the IESO Nova Scotia. Have you considered, for a future update to the Path to 2030, since most of these projects are not Nova Scotia Power projects, to perhaps having a joint panel, or asking the IESO if they want to join you on a panel to discuss the Path to 2030?

I'm looking at the IESO people right now.

A. (Pickles) That's a novel idea. Certainly I think, you know, the outcomes from the Integrated Resource Plan which they're actively working on, I think will help sort of paint a picture of the future. Not to say what you're suggesting couldn't happen, but I think that might help ---

Q. Yeah.

A. (Pickles) --- make that decision.

Q. Okay.

Okay, I'm going to turn to -- again, it's going to be an exhibit, N-6, which is one we were just at.

THE CHAIR: And, Rob, I don't think I put the page number on this one. So it's IR-182, Board IR-182. Okay. And it's (a).

BY THE CHAIR:

Q. And the question was:

> Given that the Plan is projected to cost approximately $1.3 [billion] over 5 years, has NS Power calculated the impact on rates the Plan will have?

And if we just go to the answer?

And this was explored to some extent, I think, from some questioning from Ms. Rudderham for the Industrial Group, but the answer is:

> The increased investment [for '25, '26, and '27] related to the... investment plan are [all] included in the General Rate Application currently before the NSEB in matter M12451. The Five-Year Reliability Plan is the investment amount required for Nova Scotia Power to achieve Board-established performance standards by 2029.

So my read on that answer is that the performance standards are currently in place, they have to be met, and, therefore, you have to do what is required to meet those standards. And the impact on rates, the only way you're considering that is through a GRA by having the lowest -- least cost option to achieve what you're looking for in those performance standards. Would that be the approach that you're taking?

A. (Beaton) Correct. So it's true that we would have went through an exercise to figure out the least cost option to meet the performance standards in 2029.

This plan represents the work that is required to do just that. All the work in here is related to being done in the least cost method. So from a granularity perspective, we consider affordability in that respect. And then, from an overall planning perspective, is this a reasonable amount to be investing we feel was discussed at great length through the GRA process and remains the best avenue to determine whether it's an appropriate amount and to proceed as such.

Q. Right. And I suppose the GRA -- what's included in the GRA revenue requirement for '26 and

27, obviously, if the plan changed, the future GRAs would have to consider it as well?

A. (Beaton) Certainly.

Q. If -- well, I'll leave that aside. I'll ask it later or ask it in a different way. I had a question on that.

Maybe turning to 182(b). And this question was about whether Nova Scotia Power had sought feedback from ratepayers about foregoing some of the improvements that we're discussing in the performance metrics in the Five-Year Reliability Plan to alleviate rate pressure, and we go to the response to (b). And this talks about what's been discussed previously as well.

It talks about the ongoing review of the performance standards being in place from '27 to '31 and NS Power expects that the appropriateness of the standards themselves would be discussed in further detail during the review. Customer representatives will have an opportunity to provide feedback about the appropriateness of the standards, and the NSEB will be able to make the final decision on this after this feedback is received.

So there is a review that's, I guess -- has it started yet? I'm not involved in the five-year review. I'm involved in the annual review this year.

A. (MacMullin) It has started.

[2:09:52] **Q.** Okay. And at this stage in the process, has there been any suggestion by anyone that the standards are going to be lessened as opposed to more stringent?

A. (MacMullin) There has been no indication to that effect at this time.

Q. And the current spending -- because right now, we're also having a review of the Five-Year Reliability Plan being done by Synapse, which is ongoing, and I guess just recently there was a slight extension of time, so it looks like we're going to September before that review will be done.

My question is, are we -- if we

approve the 2026 ACE Plan, is that sort of a “No-regrets” approval? In other words, would that amount be needed, in any event, no matter what the review of the plan turns up?

And why, if that’s the case, because I’m assuming I know the answer to that, but from your perspective.

A. (MacMullin) Absolutely confident in the plan that’s put before you, that it is foundational, again, to the operation of the system.

So you know, much of the plan is about sustaining the safe operation and the effective operation, the reliable operation of the power system. Those things are core to this. And then we have that incremental look ahead that’s, again, investing in core elements of the system.

So the things that we’re doing here with cutting trees, replacing poles, upgrading conductor, things of that nature, these are not things that would not stand alone. So while they absolutely have a reliability impact and benefit, they are still required and necessary to sustain the system.

Q. So if I ask the -- when I ask the question, given the ongoing review of the performance standards and the review that's taking place by Synapse, why wouldn't we just pause the implementation of this plan until those reviews are done?

A. (MacMullin) And to clarify, you're referring to the Five-Year Reliability Plan?

Q. Five-Year Reliability Plan.

A. (MacMullin) Yeah. So again, I would point out that, you know, there's much of the plan that is, again, addressing things such as load growth and, again, the sustained, safe operation and reliable operation of the power system. So that we are looking at foundational investments, so these are things that are based on and coming forth as a result of our feeder inspection results, as a result of the look into the criticality and the condition of the assets.

So while we certainly have, you know, demonstrated the reliability benefit associated with them, they are key foundational sustaining elements of running a power -- an overhead power system.

Q. My final questions were on the vegetation management aspect, but those were pretty well covered in detail, so I don't have anything additional there.

So those are all my questions for the panel.

THE CHAIR: So at this stage that completes the -- I guess the direction examination and cross-examination and Board questioning, so we'll go back around to see if there are any questions arising.

So we'll go in reverse order from what we usually do.

So Mr. Mahody, anything arising from Board questions?

MR. MAHODY: Nothing arising. Thank

you.

THE CHAIR: Okay. Just let me get my list out.

Mr. -- I guess it would be -- Mr. Kayter would be next on the list if we go in reverse order.

MR. KAYTER: Thank you, Chair. Nothing from the Minister.

THE CHAIR: Okay. And from the -- I guess so Nova Scotia.

MR. LUTHER: Thank you, Mr. Chair. Nothing from the IESO.

THE CHAIR: And Port Hawkesbury Paper.

MS. GILLIS: No questions, Mr. Chair.

THE CHAIR: The Industrial Group.

MS. RUDDERHAM: No additional questions, Mr. Chair. Thank you.

THE CHAIR: Thank you.

The Small Business Advocate.

MS. POWELL: No additional questions.

Thank you.

THE CHAIR: And the Consumer Advocate.

MR. MURPHY: Nothing arising.

Thank you.

THE CHAIR: And any re-direct from Nova Scotia Power?

MS. POWER: No, thank you, Mr. Chair.

THE CHAIR: Thank you all.

So that completes the examination of the panel. I thank you for your patience and your time today and yesterday. I know it's a long haul when you're on there for a day and a half.

And for Ms. MacMullin on your first appearance, nobody took it easy on you, so -- but that's to be expected in these type of proceedings.

So with that, you're released from the panel and we'll move on to the next witness. So thank you very much.

(**WITNESS PANEL WITHDRAWS)**

MR. MAHODY: And so Mr. Chair, I understand up next would be Mr. Wilson. And my understanding, based on discussion with counsel, is that Mr. Kayter is the only counsel with cross-examination questions for Mr. Wilson.

THE CHAIR: Okay. So maybe we can take -- should we take five or 10 minutes to allow for setup and then we can come back? So let's say 10 minutes to make sure everybody has a chance and then we'll come back to start with the -- I guess the presentation of the evidence, acceptance of the evidence and then cross-examination. Thank you.

--- Upon recessing at 2:15 p.m.

--- Upon resuming at 2:24 p.m.

THE CHAIR: Mr. Roberts, I'll just start by swearing in Mr. Wilson and then you can go through your presentation or your introduction and so forth.

JOHN WILSON, Solemnly Affirmed:

THE CHAIR: Thank you.

Over to Mr. Roberts.

MR. ROBERTS: Thank you.

EXAMINATION ON QUALIFICATIONS BY MR. ROBERTS

Q. Good afternoon, Mr. Wilson.

A. Good afternoon, Mr. Roberts. Nice to see you.

Q. You are a consultant with the firm Grid Strategies?

A. Yes.

Q. And you've prepared evidence on behalf of the Consumer Advocate in this matter which has been received as Exhibit N-9?

A. Yes.

Q. And you've also assisted the Consumer Advocate in preparing responses to information requests from the Industry Group which are found at Exhibit N-11.

A. Yes.

Q. I'm just going to ask you a few questions about your background, Mr. Wilson.

As part of Exhibit N-9, you've provided your *curriculum vitae* which contains an outline of your professional history and experience, and we find that beginning at page 29 of Exhibit N-9. Can you identify that, Mr. Wilson?

A. Yes, that is my *curriculum vitae*. Yes.

Q. Thank you.

And just briefly reviewing it, you have provided evidence in the form of expert testimony regarding utility regulation before a number of regulatory bodies, including this Board?

A. That's correct.

Q. And you've given evidence, by my count, in over 25 matters before this Board and its predecessor on behalf of the Consumer Advocate regarding the regulation of electricity and gas utilities?

A. That's correct.

Q. And that included testimony regarding previous six Annual Capital Expenditure Plans which Nova Scotia Power submitted to the Board or its predecessor?

A. Yes. I'm getting rather used to these proceedings.

Q. Okay. Thank you.

MR. ROBERTS: And with that in mind, I could go into Mr. Wilson's background in more detail, but I think he's well known to the Board that I'm going to ask that he be qualified at this time.

THE CHAIR: Mr. Wilson has appeared before this Board many times, been qualified every time he's appeared. I am going to qualify him without even asking anybody because if anybody objects, I don't see a basis for doing so.

So we're going to qualify Mr. Wilson

as an expert in this proceeding.

MR. ROBERTS: Thank you.

DIRECT EXAMINATION BY MR. ROBERTS

Q. And Mr. Wilson, then I'll ask you to return to Exhibit N-9. First of all, if you could confirm that you prepared this evidence yourself?

A. I did.

Q. And are there any corrections that you wish to make to your evidence?

A. No.

Q. Okay. And are the facts on which your evidence and opinions are based true and accurate to the best of your knowledge and belief?

A. Yes, considering additional testimony, of course, that's happened in this proceeding.

Q. Fair enough. And are the opinions expressed in Exhibit N-9 your own?

A. Yes.

Q. And do you adopt Exhibit N-9 as

your testimony in this proceeding?

A. Yes.

Q. Thank you.

And since you prepared your testimony, Nova Scotia Power has filed rebuttal evidence, which has been received by the Board as Exhibit N-12. Have you reviewed Exhibit N-12?

A. Yes.

Q. And does the rebuttal evidence of Nova Scotia Power cause you to change your opinions or recommendations in any way?

A. Generally, no.

Q. All right. Thank you.

MR. ROBERTS: At this point, I would propose that Mr. Wilson be available for cross-examination.

THE CHAIR: Thank you, Mr. Roberts.

And as I understand, it's been discussed prior to the break, or at least at the start of the session this afternoon, Mr. Kayter, from the Department of Energy Nova Scotia, is the only person with cross-examining questions. He'll be coming up to the cross-examination table.

Please proceed, Mr. Kayter.

MR. KAYTER: Thank you, Mr. Chair.

To whom would I face for the cameras so that Mr. Wilson can see me straight on?

THE CHAIR: Straight ahead. There's one right in front of you.

MR. KAYTER: Thank you.

CROSS-EXAMINATION BY MR. KAYTER

Q. Good afternoon, Mr. Wilson. I'm Thomas Kayter. I represent the Department of Energy. With me is Girish Patel, an engineer with the department.

I have some questions for you, but before I get into the questions I have written out, I want to pick up some answers that you gave to Mr. Roberts.

You were asked about Exhibit N-12 and your response as to whether or not your opinions would change on the basis of that exhibit was "generally, no". What did you mean by "generally, no", and is there any specific opinion that would change on the basis of that exhibit?

[2:29:57] **A.** Well, the -- so I think I made a total of -- let me check -- I believe 14 recommendations in my -- 13 recommendations plus two additional comments in my evidence, and I still stand behind each of those.

There were some factual comments in the rebuttal evidence and then also in the cross-examination in particular yesterday that would sort of change my opinion about the context in which those -- some of those recommendations would be made, but they wouldn't be material to the recommendations themselves. So that's what I meant by generally.

I think, you know, new information always is important and informs one's point of view.

Q. Speaking of new information, you made reference indirectly to new information in one of your answers to Mr. Roberts when he asked you if you stood behind your opinions as generally outlined in Exhibit N-9. And you added a caveat to your answer that basically said, "Subject to the testimony in these hearings"; have you been participating or following along?

A. In general, yes. I can't say that I've attended every moment of the hearings, but I have attended the vast majority.

Q. Okay. So have any of those opinions changed, or do you want to change or provide any additional opinion based on any of the evidence that you heard here from the panel over the last two days?

A. Well, I guess I'd have to go through the transcript to give you sort of a detailed and probably rather tedious set of answers to that question. But a good example that comes to mind is the forthcoming undertaking -- I believe it was the very first undertaking -- and that was regarding the definition of -- now I'm blanking on the word. I apologize. Transactions and labour hours in the measurements of the Maximus sales force application, the work asset management program.

And you know, my understanding from that conversation is that the number of labour hours is something that is recorded for each capital program, and so we'll be seeing more detail on that in the undertaking. So subject to that undertaking and reviewing it, I imagine that some of my thoughts around those topics that relate to that would be provided in greater clarity, I guess might be the best way to put it.

Q. You have told us that you heard parts but not all of the panel's testimony over the past two days. In your experience, which has been outlined here today, which appears to be considerable testifying as an expert witness in proceedings such as these, would it be usual or unusual to be asked following these hearings to provide further opinion based on any of the evidence that was not contemplated or foreseen by any members of that panel?

A. I believe on a couple of occasions -- I'm not positive if it's occurred in an ACE Plan proceeding or not. I have provided support for filing undertakings. So I guess that would be a normal process for the Board. But otherwise, I'm not really sure what your question is getting at.

Q. Well, if there was an answer from the panel that required some clarification as per your 13 comments in your report, would it be possible to have further opinion from you based on the evidence of the panel?

A. That's a procedural question that I don't think I'm qualified to answer. I think I would defer to my counsel as to the appropriate procedure for further responses. I really don't know.

Q. But nothing that you've heard here today changes any of your opinions that are contained in your report, N-9?

A. Yeah. Particularly the recommendations, yes. I mean, I think some of the wording might change slightly based on additional facts or clarifications that have come forward from the witnesses, which is routinely the case. I don't consider that to be unusual in this proceeding in any way.

Q. Thank you.

I'd like to refer you to PDF page 12 of Exhibit N-9, number 4, Contingency for Projects Without Risk Matrices.

Mr. Wilson, in your evidence you

recommend reducing the default contingency from 15 percent to 10 percent for projects without a risk matrix. Would allowing a 15 percent blanket contingency across several capital projects without specific risk justification contribute to asset inflation concerns, and what is in place to mitigate this?

A. Contribute to asset inflation? I'm sorry; I lost the wording there.

Q. My question again is, would allowing a 15 percent blanket contingency across several capital projects without specific risk justification contribute to asset inflation concerns, and what is in place to mitigate this?

A. If by "asset inflation concerns" you mean that increasing the contingency directly leads to additional assets being placed in rate base, that's not a direct result of that. If I can, maybe I can explain what I think the advantages of setting the contingency level at an appropriate level are, and then maybe there's a follow-up question on that.

So setting the contingency level at 10 percent rather than 15 percent creates a couple of benefits. First is that it creates a more appropriate signal to the staff of Nova Scotia Power to control costs and to keep the ultimate cost of the project down, which would be placed in the rate base. So it’s an indirect effect on the, as you call it, asset inflation, but I would just call it the amount that’s put into rate base.

You know, as was discussed yesterday, and I agree with the Nova Scotia Power witnesses, the cost of the project is ultimately the cost, and if it’s deemed prudent, it goes into rate base. So whether the contingency is 10 percent or 15 percent, the cost goes into rate base.

The second effect is on the triggering mechanism for the authorization to overspend proceedings. And if the contingency is set too high, that creates, in a sense, an artificially increased trigger for the ATO proceeding. And in that case, the Board doesn't have, you know, an automatic situation where the project would be reviewed and the -- an understanding of why the project went over budget developed and canvassed. And then there would not be also, you know, as clear an opportunity to determine whether those reasons were prudent or otherwise.

So to me, it is important that the contingency level be set appropriately, again in summary, just to sort of incentivize sort of in an informational or kind of providing a target for the staff to keep the costs low and then, secondly, to make sure that the appropriate regulatory follow-up occurs given the facts of the case -- or excuse me, of the project as it was originally proposed.

So I don't think it leads directly to asset inflation, but it's certainly a factor in helping to minimize costs, which then keeps the assets in rate base to the minimal level possible.

Q. Thank you. You've answered our

question.

If I could move to the next question by referring you to PDF page 15 of Exhibit N-9. Number 5, Reliability Related Projects.

The question is this. You've noted Nova Scotia Power's attribution of tree contacts during adverse weather is based on an imprecise 40 percent estimate. If the utility cannot accurately measure the cause of outages, how can the Board, the Department or consumers have confidence that the millions spent on reliability projects are targeting the right problems?

And let me know if you need me to repeat that question.

A. No, I follow it, I think.

So yesterday I think we had a good discussion about where that 40 percent comes from, and there was the description of the snow-covered trees leaning down and touching the wire and then coming back up and -- so the staff were not able to identify -- Nova

Scotia Power's field staff were not able to sort of state with certainty that it was a tree contact that caused the outage versus, you know, some other cause. And so they use this "approximate 40 percent". And I have a couple of concerns with that.

One is that that estimate, you know, which is up to 40 percent was the way it was phrased, and was set back in 2019, I believe, hasn't changed over the past seven years. And so we're having a lot of investments to -- you know, to drive -- in vegetation management to drive these kinds of tree contacts down, but there's no way to sort of track whether that is having an effect on these adverse weather-related tree contacts, which is where this 40 percent number comes from.

[2:40:20] So it does raise concern for me that a significant component of the benefit of the vegetation management is very difficult for Nova Scotia Power to track and for the Board then to understand that the investment that it is supporting in this work is actually to the benefit of Nova Scotia Power customers through increased reliability during storm events.

So I think that's kind of a big challenge for this program and I'd like to see Nova Scotia Power look a little bit more deeply at a way to maybe come up with an indicator, even if it's not a complete measure of these tree contact outages during adverse weather and add that to its Reliability Plan. That would be something that I think would be really helpful.

But I don't -- you know, I don't think everything is knowable about outage events. I think that's an unfortunate reality of these programs. So I want to both challenge Nova Scotia Power to do a little bit better in this area, but also give them a little bit of grace that it is not a situation where these facts are knowable. And what's important in the moment, of course, when those field staff are out there, is getting the power back on, not in sort of stopping and conducting a forensic investigation of the site.

Q. Mr. Wilson, is there anything across industry that is happening that Nova Scotia Power may not be doing? With particular reference to new emerging technologies such as AI, for example, where, across industry, they are using technologies to more -- I mean, there's no crystal ball, obviously, but more accurately attempt to map and predict weather-related outages?

A. To map and predict.

If you're going to narrow your question to that, I'm not aware of any technologies that are being used in the industry to map and predict weather-related ---

Q. Maybe I'll ask it more broadly, then.

Is there anything across industry that other related power companies are doing that Nova Scotia Power is not doing in relation ---

A. I think there are things that

Nova Scotia Power is beginning to do. I think we've seen a lot of improvement in their efforts over the past few years.

You know, as we discussed, I've been handling these proceedings for six or seven years now for the Consumer Advocate and, at the beginning of my work on these proceedings, cost minimization was a real important focus of the Board, as it remains today. And a lot of the initial recommendations and critiques took a couple of years for Nova Scotia Power to embrace, and then gradually we've seen improvements there. And so certainly in certain aspects of Nova Scotia Power's overall operations, I have testified that I've seen improvement. And in fact, the Board has acknowledged that and has removed some of the reporting requirements related to cost-minimization, having been satisfied that improved practices were in place.

There's aspects of Nova Scotia Power's operations that I do not think have been fully demonstrated to have achieved cost minimization. That’s why, in the last couple of years, we’ve been really focused on these distribution routines and transmission routines and the Reliability Plan.

And I’m really glad to see that the third-party Reliability Plan review is under way. That's a major reason why I focused a little bit less on that topic in this year’s evidence, although I did focus on cost effectiveness measures, and that’s an area where I think Nova Scotia Power could improve.

I think that, you know, there’s some other aspects of the -- you know, I mean, there’s a number of areas where I think cost minimization could still be pursued effectively with Nova Scotia Power, but I do want to acknowledge that they’ve made significant improvements.

I’ll give one other example, and then I’ll pause and see where I might not have fully answered your question.

The Vegetation Management Program, you

know, we heard a lot about how much has been invested over the past five to seven years, say, in that. And I share the Board's concern that a lot of that has not proven to be as effective as we hoped it would be.

I do think it's important to note that the recommendations that were brought forward back in as early as 2024 have been adopted by Nova Scotia Power to look at trees outside of the right-of-way and otherwise really kind of look more broadly at tree contacts. And I think that, you know, we have yet to see evidence that that practice, which really has only been underway a little over a year, is having benefits yet, but I would hope to see those benefits within the next year or two and I look forward also to the third-party review of the Reliability Plan to see what those experts' opinions are of the new practices.

Q. Mr. Wilson, you've named two aspects of Nova Scotia Power's operations that you said you felt did not necessarily achieve cost minimization.

Could you name any other areas where aspects of Nova Scotia Power's operations that you don't feel achieve this?

A. Another area that I continue to have concerns with is the civil aspects of hydroelectric projects. We've had some discussion today, I think, about Tusket and Mitchell Falls -- or excuse me, Marshall Falls. So those are examples of projects that have gone over budget. Gaspereau is another one that has got some concerns.

So I think kind of across the board, the civil-related hydroelectric work is one where I still put a lot of attention whenever I have the opportunity to review those projects because of the substantial cost overruns in those projects.

Q. Thank you.

A. That'd be another example.

Q. Are there any other aspects that you can note?

A. Yeah. This is going a little bit -- I don't believe I collected a list of those things for this testimony so I'm doing this a bit from memory here.

I think there have been some operational issues that have been canvassed in the FAM proceeding that I've had concerns about. I wouldn't say they are systemic. They're more evidence that a -- you know, quality assurance and cost minimization practices that are in place in a lot of those operations sort of need to be ---

MS. POWER: Mr. Chair, I don't want to interrupt Mr. Wilson's flow, but if we're talking about matters that are in the realm of the FAM Audit, I don't think it's relevant to the ACE proceeding.

THE CHAIR: Mr. Kayter.

MR. KAYTER: Yes, Mr. Chair. It's relevant when the witness puts those issues into play as a result of his previous answers to my questions.

He has raised the aspect of these --

or the issue of these other aspects.

THE CHAIR: The purpose of these cross-examinations, of pre-filing evidence and of dealing with evidence that's been pre-filed is that the expert opinions that are expressed are generally the ones that are presented before the Board in the written testimony. And the purpose of cross-examination is to either clarify or challenge the written evidence.

Now we're straying into areas that were not addressed in the report, that I can recall. And so I realize that sometimes the answers go beyond perhaps what you were intending to ask, but there is a role -- there is a fairness issue when it goes a little bit beyond what was the focus of Mr. Wilson's evidence.

And this, Mr. Wilson, is in no way to discuss your evidence. You're answering the questions that were asked of you. But I think it's going a little further than what actually is in your report for the purposes of this hearing, so I think that we're probably at the end of the line for that line of questioning.

MR. KAYTER: Yes, Mr. Chair. Thank you. I'll move on.

BY MR. KAYTER:

Q. Mr. Wilson, as a follow-up question to my initial question around adverse weather estimates, without precise data is there a risk that the utility's over-investing in certain areas, such as capital -- like capital replacements while neglecting more cost-effective solutions like targeted vegetation management?

A. Well, I think they're investing quite a bit in targeted vegetation management. Let me reflect on your question just...

I mean, I think there is -- I think the concern that I have with the Reliability Plan and which prompted our recommendation for a third-party review was that a lot of the decisions that were made were sort of reasonable up to a point.

Like for example, the right-of-way

widening and so forth, but -- were reasonable programs to pursue, but whether these programs were balanced correctly, whether the -- whether the investment priorities were set correctly, whether the methods that were being implemented were exactly the right methods or whether there were other, better practices out there in industry was something that, you know, we were not able to develop in evidence and present to the Board. And so we recommended, you know, a more thorough review and I think, eventually, Nova Scotia Power concurred that such a review would be helpful to it.

[2:50:28] And so that, I think, is where we're at, is that there is a risk that we have not got the right plan in place and that the plan is either unbalanced or doesn't have the best practices in it. And I'm really looking for the third-party review to help open up that conversation.

It may not be the last word on that conversation, but it -- I'm hoping that it at least opens up the right discussion points.

Q. Thank you.

For my next question, I refer you to PDF page 21 to 22 of Exhibit N-9, CEJC Updates, Scope Change Definition.

Question: Your proposal for more rigorous scope change definition aims to prevent projects from evolving into more expansive -- expensive versions of themselves post-approval. In your experience, does the current lack of a strict scope change trigger allow the utility to normalize cost overruns?

A. You know, it's interesting the conversation today that I believe Member -- Board Member Murphy brought up around IR-16 -- I'm checking my notes here -- from the Board's IR set; I believe that's Exhibit N-6 -- discussed the Tusket Falls and Marshall Falls Projects and pointed out, you know, the large cost overruns in those projects.

I think that -- I think that, you

know, there are ATO proceedings, at least, I'm certain, for Tusket Falls. The challenge there is that that ATO proceeding, a lot of evidence was developed in that proceeding and then they withdrew that or suspended that application in order to conduct further planning.

And the reason that I suggested a cost threshold, in addition to the language that Nova Scotia Power puts forward, is I feel like for projects like Tusket Falls and perhaps Marshall Falls that there needs to be process where, when there's such a large change, that the Board has an immediate and clear opportunity to reconsider whether the project was appropriately scoped in the first place.

And so in that case, Nova Scotia Power is not proposing a change that -- in the project and I think, you know, they've testified that the Tusket Falls case would not meet their scope change threshold, but I feel like -- you know, looking back at that project and the testimony in that case, I feel like a scope change proceeding would have been appropriate at that point as a good example of one where the magnitude of the change in the project was so large that, you know, decommissioning or partial decommissioning should have been fully reconsidered and put before the Board in a full case.

So I do think there are cases where scope change can be just the magnitude and challenge of the project and not simply a change in what the type of project is that Nova Scotia Power now wishes to pursue might be.

So that’s kind of what I’m getting at there.

And I think there’s other examples. I think there’s several IRs in the Board’s IR set in Exhibit N-6 that go through sort of what are the projects that are currently before the Board that would trigger ATOs, and so I think the Board might look at those projects and think about which of those kind of represents scope changes and which of those represent more just incremental cost overruns and see if there's sort of a dividing line that would be helpful in identifying projects that should be brought forward for reconsideration in order to ensure that excessive spending doesn't move forward without Board oversight.

Q. Thank you.

My next question, I'll refer you to N-9, page 6. You note that Nova Scotia Power does not track regular and overtime person hours for several capital routines. In your opinion, does this lack of visibility contribute to an unchecked increase in the cost per new customer for distribution work?

A. Yeah. So the premise of your question, I think, is one of the things I referred to earlier, which is that the Nova Scotia Power panel identified that they do track hours for -- to the capital routines. So that was different than what they stated in the IR response that I relied on in my testimony.

The second part of your question,

though, was sort of does the lack of visibility -- and I've forgotten about exactly how you phrased it, but basically does this lead to higher costs, I think, was kind of the gist of your question. Is that right?

Q. Yes. In your expert opinion, does this lack of visibility contribute to an unchecked increase in the cost per new customer for distribution work?

A. Yeah. So the cost per new customer would refer specifically to the new customer distribution routine. And I think the concern I have is the work asset management program, the Maximo/Salesforce software, is not being used to its full capability to manage those costs and to see if costs for new customer routines or, really, for a number of the distribution routines are minimized.

So for example, assuming that this transactions per hour metric is kind of what I think it is, one could look at that year over year for the new distribution -- excuse me, for the new customer distribution routine and see if that number is trending downwards. And one would hope that sort of work would become more efficient as scheduling practices are improved.

And I know that the panel explained why they were opposed to simply using the basis of schedule method from the PDM in distribution routines, but some kind of scheduling practice that sort of looks at, geographically, where do we need to position crews, where can we move them around more efficiently, et cetera, would be helpful to reducing costs.

And I'll give an example from the industry, which is distributed solar. And I've seen some papers and heard some interviews with experts that talk about how inexpensive distributed solar installation is in Australia compared to other markets in the world. And one of the reasons is, is they have a very simplified permitting process, but also the installers use very aggressive scheduling methods in order to make sure that their crews go out only to a single neighbourhood and complete all of the available work in that neighbourhood before moving on to the next.

So you know, if one of us lived in Australia and wanted to put solar on our house, we might have to wait several weeks for our neighbourhood to come up in the queue and get the installation done, but then it’s done very quickly and efficiently, and then the crew moves on to the next installation.

And I think the same thing could be true for a number of the distribution routines, is that this work asset management software could be used not only to make sure that all of the projects are handled, but rather than sort of using what I imagine may be a first-in/first-out system of handling those assignments, using more geographic or assigning particular crews to particular projects based on their special expertise, et cetera.

So those would be the kind of things that some kind of a transactions per hour metric at the capital program level might be able to help track and see that cost improvements are being achieved.

Q. Mr. Wilson, based on your experience in different jurisdictions, how does the average cost per customer in Nova Scotia compare with other Canadian jurisdictions?

A. I don't have that information.

Q. You've made several suggestions regarding efficiency improvement. What impact does the lack of efficiency on the utility and tracking actual labour hours required for a project have on determining how just and reasonable the ACE Plan is?

MS. POWER: Excuse me, Mr. Chair. I'm just -- I'm not sure these questions are entirely fair to Mr. Wilson or that Mr. Wilson is qualified to give a position on questions like this.

He's not here to speak to his

experience in all these different jurisdictions. We're here to speak about the ACE Plan in his evidence. Could we please keep it squarely within that?

THE CHAIR: Mr. Kayter?

MR. KAYTER: Mr. Chair, I thank my friend for her objection, but I believe the witness is that of Mr. Roberts. And I hear her objection, but Mr. Roberts has brought Mr. Wilson as the expert witness for the proceedings and, you know, I have obviously spoken with Mr. Roberts about what my intended questions would be and given him a sense of where we were going here. So perhaps we'd hear from Mr. Roberts if he has an objection and we can take it from Mr. Roberts.

[3:00:23] **THE CHAIR:** I will hear from Mr. Roberts, but then I'll hear reply from Ms. Power.

So Mr. Roberts, do you have any comments on this?

MR. ROBERTS: I really don't. I mean, if it's -- obviously, Mr. Wilson was not comfortable answering the last question that was put to him and said so squarely. Within the confines of relevance, if he wants to answer, I don't know why he can't, but I also hear my friend in terms of the scope of his testimony as it's presented in his report.

THE CHAIR: Ms. Power?

MS. POWER: Yes. And I respect and accept that these questions were put to Mr. Wilson or the CA in advance, but Mr. Wilson was retained for a specific purpose with a specific subset of questions to provide evidence in this proceeding, and his testimony should stick to the evidence that he's provided.

THE CHAIR: Mr. Kayter, could you just repeat the question again? Now that I've heard the objection, I'll see what the ---

MR. KAYTER: If I could just have a moment?

Mr. Chair, Mr. Wilson has referred to efficiency improvement measures in his report, and it is our position that this question pertains to efficiency improvement. Again, my question is this: You've made several suggestions regarding efficiency improvement. What impact does the lack of efficiency of the utility in tracking actual labour hours -- this is in his report -- required for a project have on determining what is effectively the ultimate question for the Board?

I mean, I don't know how that is objectionable. It is based on his report and the ultimate question before the Board, which is the justness and reasonableness of this entire ACE Plan.

THE CHAIR: I -- well, I'll hear Mr. Wilson's response to that. That is something that's tied to the report and that he may or may not be able to address.

So Mr. Wilson.

MR. WILSON: Yes. So again, the premise of the question is the utility doesn't track actual labour hours to the project, I believe. And I think on an earlier question I pointed out that that was a Nova Scotia Power staff during -- I think the usefulness of that information is in identifying whether Nova Scotia Power's work on these distribution routines in particular is efficient in achieving full cost minimization.

And I don't think that, you know, I would argue for any kind of finding of imprudence in the current proposal. Based on that information, I think this is very similar to the work that the Board has done over the past few years in encouraging Nova Scotia Power to develop new cost minimization strategies across its capital program. And this is simply one of the areas where the cost minimization practices that the Board has developed don't really apply.

The PDM, the project development or delivery model, doesn't really apply very well or much at all to most of the distribution and transmission routines and so, because of that, we need to find other ways to track and verify that the utility is looking at risks, looking at scheduling, looking at overall optimization of costs, and finding metrics that help indicate where it’s being successful or where it may need to work harder to achieve the best cost for customers.

So I think it’s really more of a forward-looking, rather than a backward-looking, critique.

BY MR. KAYTER:

Q. Mr. Wilson, in response to two of my questions now you have referred to a change in your opinion from your report because of evidence that you’ve heard from the panel.

Now, I began asking questions about how, if at all, any of your opinions would have changed as a consequence of having heard from the panel. I noted, and forgive me if I didn’t capture everything, that as a result of some of the -- I think it was the Industrial Group’s IRs, your opinion about the steps taken to avoid duplication in cost had changed.

Are there any other areas that I may

not have -- and forgive me; it may just have been my inability to note quickly enough your response, but if I could just go back again, having heard from the panel, how, if at all, have any of your opinions changed from that -- those contained in N-9?

A. If I can have just a moment, I'll look through the recommendations and see if there's anything else that comes to mind.

Q. Thank you.

(SHORT PAUSE)

MR. WILSON: I can confirm that I think the recommendations as summarized on pages 3 and 4 of my testimony is enumerated on the page themselves, are still my recommendations exactly as written.

The conversation we had throughout this testimony about the labour hours directly relates to my reasoning for making recommendations 1 through 3. And in my opinion, the evidence that has come forward strengthens the rationale that those recommendations are both practical and could be of benefit to Nova Scotia Power in minimizing costs.

I think the other area where I've heard testimony that helps sort of fill in some of the dots has been on my recommendations 8 -- yeah, recommendation 8 relating to the tree contacts issue. And again, I would say there it just strengthens my view that the Board, you know, and I think has appropriately highlighted during this proceeding its concerns about the effectiveness of the Vegetation Management Program and other related Reliability Plan programs and I would assume that the -- you know, some representatives of the team responsible for conducting the third-party review of the Five-Year Reliability Plan are monitoring this proceeding and are taking note of points being made by Commissioner -- by Board Members and other parties in this proceeding.

So, you know, I think I'm satisfied that my recommendations, you know, stand and should be adopted by the Board, given its consideration and sort of, in some cases, I left some points, you know, sort of to the Board's discretion and others that I made more concretely.

BY MR. KAYTER:

Q. Thank you, Mr. Wilson.

Two questions anticipated to conclusion.

How do escalations observed in the 2026 ACE Plan compare to...

[3:10:04] **MR. KAYTER:** Mr. Chair, I'm just going to -- I'm going to retract that question, and I have to rephrase that.

THE CHAIR: Sure.

BY MR. KAYTER:

Q. Mr. Wilson, can you say what level of escalations are generally acceptable? Are there benchmarks or standards?

A. Can you explain what you mean by the word "escalations"?

Q. In particular in relation to project costs.

A. You mean -- so for example, whether a project cost goes over budget, a specific project?

Q. Yes.

A. So for a specific project, the -- you know, I'm generally supportive of the Board's overall policies on cost overruns. There is a -- there are non-binding contingency guidelines. You know, as noted in my testimony, I've got a recommendation related to transmission projects that don't have risk matrices and recommending that the Board sort of set a default or cap or however the Board wishes to phrase it, 10 percent contingency amount, on those projects.

But in general, I think the non-binding contingency guidelines have been worked out effectively and Nova Scotia Power's generally following those. So that's one mechanism for determining what level is reasonable for a project, is simply that it should ideally stay within the cost escalation boundaries that are set by the contingency approved by the Board when the project is approved.

Then I think the second aspect of that is when it goes over that contingency, there's the potential for an ATO proceeding to review that and determine whether that cost is reasonable.

And then, of course, the third opportunity is during a general rate case if there has not been an ATO proceeding but there is a concern that the rate base is too high because of cost overruns that were not just and reasonable or justified, or whatever phrasing we might want to apply in that circumstance, then that would be sort of a third avenue for it.

So I don't think you can sort of say that there's a single percent that one can say is the amount of cost escalation for a specific approved capital project that can be expected to be reasonable and then, above that, it’s unreasonable. It’s really on a project-by-project basis and also one of the reasons for that cost overrun.

Does that help?

Q. Yes, it does, Mr. Wilson.

Further to that, though, are there any undeployed cost containment measures that the Board could use to mandate -- the Board could mandate to mitigate overruns?

A. Well, I think there’s the recommendations that I’ve put forward in my testimony. I’m happy to go through those, but those are written out. So that would be the main area.

And then as I discussed, you know, really looking forward to the third-party review of the Five-Year Reliability Plan to develop additional recommendations.

And I think there’s a number of capital projects that are underway that I think will lead to cost minimization opportunities. These are mainly in the IT space, so there's the -- you know, and some of these go beyond the scope of the ACE Plan in their implementation, but they are approved in the ACE Plan proceeding.

So for example, the Work Asset Management Program, I think there's more potential for it to have success. There are some grid-enhancing technology initial steps that are being put in place. I think those are going to be important opportunities to minimize costs in transmission expansion and overall reduce congestion loads on the system.

I think the -- you know, some of the projects that have been identified through the IRP and subsequent planning processes are really important to making sure that we get the most and highest use out of generation assets, so that would be the synchronous condensers or, you know, whatever solution is approved in the forthcoming proceeding on that topic. So you've got a lot of technology up there that Nova Scotia Power is in the process of implementing that I think may help mitigate ongoing costs and also may help avoid unnecessary projects or unnecessarily expensive projects. But, you know, I think we've already discussed areas where I continue to have concerns such as the hydro -- civil hydroelectric projects and the way that those are being managed and the cost implications of those on customers. And I did have a discussion of the Mersey Hydro Project in my testimony as well.

Q. Mr. Wilson, are any of those, either that you referenced or that you haven't referenced, directly related to increasing costs due to third-party vendors or supply chain issues?

A. I mean, third-party vendor and supply chain issues are an issue in every jurisdiction that I'm working in right now. So, yes, I think costs are going up as a result of those issues. I do have a recommendation in my testimony or my evidence regarding the use of pooling practices for advanced procurement of key infrastructure and potentially with some cost-effectiveness opportunities. You know, that would be an example of a supply chain -- not a complete solution but at least a mitigation to those issues. But in the end, a lot of the supply chain cost increases are being driven by underlying raw material cost increases and so it’s really challenging to sort of solve that problem from a single utility’s point of view. It kind of requires more of an industry-wide approach.

Q. In this case, would that be like New Brunswick, PEI, Newfoundland, their utilities pooling ---

A. Yes.

Q. Yeah. Okay.

A. Yeah, pooling -- very specific Proponents, you know, that they all use in common. And I know that there is a degree of common procurement practices. I have some of that discussed in my testimony, but I can't recall the details of that to mind immediately. But, you know, the idea being that, you know, there's an expectation that each utility, say, is going to need a certain kind of circuit breaker, maybe two or three per year, but sometimes it's zero, and sometimes it's more like five or six, and the idea being that rather than sort of waiting until you need them to procure them, you procure them in advance, you get more advantageous pricing in that way, but then they're sort of stored by one of the member utilities in the pool, and then they draw from that pool as they need them.

So it's a cost-minimization strategy but it requires collaboration, and it really requires a lot of expertise also in terms of planning that, because what you don't want to do is have an excessively large inventory sitting around that's not drawn on efficiently. So that's a challenge there is that you have to have that kind of planning expertise that spans multiple utilities, and that, you know, takes some time to develop.

Q. Mr. Wilson, thank you for answering our questions today.

MR. KAYTER: Mr. Chair and Members of the Board, those are the questions from the Department of Energy, may it please the Board.

THE CHAIR: Thank you, Mr. Kayter.

MR. KAYTER: If we could be excused?

THE CHAIR: Yes.

MR. KAYTER: Thank you.

THE CHAIR: At this stage I will ask Board Members if there's any questions arising from -- or questions for Mr. Wilson.

So Ms. Nicholson?

MEMBER NICHOLSON: Nothing from me.

Thank you.

THE CHAIR: And Mr. Murphy?

MEMBER MURPHY: None from me, Mr. Chair.

THE CHAIR: And I do not either.

So I'll go back around in reverse order to come to Mr. Roberts.

So, Mr. Mahody, any questions arise from his cross-examination?

MR. MAHODY: No, Mr. Chair.

Thank you.

[3:20:01] **THE CHAIR:** Well, I guess Mr. Peachey for the IESO?

MR. PEACHEY: No questions, Mr. Chair.

THE CHAIR: Okay. Port Hawkesbury Paper?

MS. GILLIS: No questions.

Thank you.

THE CHAIR: For the Industrial Group?

MS. RUDDERHAM: No additional questions. But I did want to flag that I don't believe Mr. Wilson adopted N-11, which would have been responses to the IG IRs. I don't know if that was something that we wanted to do or not.

THE CHAIR: We can do it at the end, if that's the case. I just can't remember. But Mr. Roberts perhaps you can do that when we come back. It might be the easiest way to do it.

So the Small Business Advocate?

MS. POWELL: No questions arising.

Thank you, Mr. Chair.

THE CHAIR: And Nova Scotia Power?

MS. POWER: No, thank you, Mr. Chair.

THE CHAIR: So, Mr. Roberts, any re-direct?

And perhaps -- I just can't remember if N-11 is adopted.

MR. ROBERTS: No re-direct.

And I would just say that N-11 is actually the responses of the Consumer Advocate. The question which Mr. Wilson confirmed was that he assisted us in doing that. But they're actually evidence presented by the Consumer Advocate.

THE CHAIR: Okay. Okay, thanks.

So I believe that completes the testimony. Mr. Wilson, the Board thanks you for attendance today and you're excused from the witness stand or your witness chair where you are now.

Thank you.

(WITNESS WITHDRAWS)

THE CHAIR: Okay. So that -- actually, well, I'll just confirm to make sure if there's any rebuttal evidence from Nova Scotia Power.

MS. POWER: No, thank you, Mr. Chair.

THE CHAIR: Okay. So that completes the evidence.

So we have to discuss the undertakings and then submissions. So for undertakings how long would you expect Nova Scotia Power to have the undertakings ready?

MS. POWER: I would like two weeks, Mr. Chair, which brings us to May the 6^{th}.

THE CHAIR: May the 6th. Okay.

MS. POWER: But I might take a minute to speak to my friends about the rest of the schedule if that's okay.

THE CHAIR: Sure. Let's just -- we're going to stay here but maybe break and discuss it.

--- Upon recessing at 3:24 p.m.

--- Upon resuming at 3:25 p.m.

THE CHAIR: Go ahead, Ms. Power.

MS. POWER: Thank you, Mr. Chair.

So we've confirmed a May 6th date for answers to undertakings, a Friday, May 29th date for all to close, and a reply to closing date of June 5th.

THE CHAIR: Okay. So I've got May 6th for undertakings, Friday, May 29th for all closing submissions to be filed at the same time, and then all parties can file rebuttals by June 5th. That sounds reasonable to me.

Hearing no other comments on that, we

will set those down and we'll send out a letter to that effect for the closing submissions. And then as usual, we'll try and get our decision out as soon as possible.

What we have done in the past two years, because we are dealing with an annual ACE Plan and we have submissions on June 5th, which makes it -- you know, half the year is already gone, so we -- those projects that the Panel can agree upon, if they have approvals, would be listed in an Order, and if not, then they'll have to wait for the decision to get that out.

So we'll do as best we can to get a decision as quickly as possible.

So with that, we will adjourn the hearing. I thank all the parties for their participation and for their assistance, and we'll adjourn.

Thank you.

--- Upon adjourning at 3:27 p.m.

CERTIFICATE OF COURT TRANSCRIBER

I, Patricia Cantle, hereby certify that I have transcribed the foregoing, and it is a true and accurate transcript of the evidence given in this matter, M12619.

____
Patricia Cantle
Registration No. 2017-001
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Halifax, Nova Scotia
Wednesday, April 22, 2026