M12451

NOVA SCOTIA ENERGY BOARD

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

- and -

IN THE MATTER OF: **OF A GENERAL RATE APPLICATION BY NOVA SCOTIA POWER INCORPORATED** for approval of certain revisions to its Rates, Charges, and Regulations

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TRANSCRIPT

HEARD BEFORE: Mr. Stephen T. McGrath, K.C. Chair
Mr. Roland A. Deveau, K.C., Vice Chair
Mr. Steven M. Murphy, MBA, P.Eng., Member

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

DATE HEARD: Thursday, January 8, 2026

APPEARANCES:

APPLICANT: **Nova Scotia Power Inc. (NSP)**
Mr. Colin J. Clarke, K.C.
Ms. Jennifer Power, Counsel
Mr. Geoffrey Breen, Counsel
Mr. Blake Williams, Senior Director, Regulatory Affairs

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

Small Business Advocate
Ms. Melissa P. MacAdam, Counsel
Ms. Rebekah L. Powell, Counsel

Affordable Energy Coalition
Mr. Peter Duke
Mr. Chris Benjamin

Eastward Energy Incorporated
Ms. Allison Coffin, MBA, P.Eng.
Ms. Angela Costello, Regulatory Analyst

EffiencyOne
Mr. James Gogan
Ms. Lucia Westin-Eastaugh

Industrial Group
Ms. Nancy G. Rubin, K.C., Counsel
Ms. Brianne Rudderham, Counsel

Municipal Electric Utilities of Nova Scotia (MEUNS)
Mr. James MacDuff, Counsel

Natural Forces
Mr. Austen Hughes
Ms. Meg Morris

Nova Scotia Department of Energy
Mr. Daniel Boyle, Counsel
Mr. Girish Patel

Nova Scotia Independent Energy System Operator (NSIESO)
Mr. Jason T. Cooke, K.C.
Ms. Danielle J. Keating, Counsel

Nova Scotia Liberal Caucus
Mr. Chris Abraham
Mr. Iain Rankin

Nova Scotia NDP Caucus
Ms. Claudia Chender
Ms. Susan Leblanc

Port Hawkesbury Paper LP
Mr. David MacDougall, Counsel
Mr. James MacDuff, Counsel
Ms. Melanie Gillis, Counsel

Renewall Energy Inc.
Mr. Daniel Roscoe, P.Eng.

SWEB Development
Mr. Mason Baker, P.Eng.

BOARD COUNSEL: Mr. William L. Mahody, K.C.

BOARD STAFF: Mr. Steve Pronko, Director, Electrical Advisory Services
Ms. Libby McNamara, Director, Risk and Financial Advisory Services
Ms. Holly Chisholm, Advisor (Economics/Finance)
Mr. Robert Norwood, Public Proceeding Assistant
Ms. Svitlana Lykhina, Public Proceeding Assistant
Mr. Jeff Goodine, Information Systems Technician

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Halifax, Nova Scotia

--- Upon commencing on Thursday, January 8 at 8:59 a.m.

THE CHAIR: Good morning, everyone.

JOHN WIEDMAYER, Previously Affirmed:

CRAIG FLEMMING, Previously Affirmed:

BLAKE WILLIAMS, Previously Affirmed:

MICHAEL WILLETT, Previously Affirmed:

JONATHAN MacINTOSH, Previously Affirmed:

THE CHAIR: Are there any preliminary matters to deal with before we resume with questioning of the panel?

Okay. I think it's up to me where we are, and I don't have a lot of questions, I do have some. Mostly just to make sure my head is correctly around the various numbers that relate to the different versions of depreciation numbers that are included in the evidence.

So Mr. Goodine, if we could perhaps start with the Application documents, Exhibit N-3, and go to page 40? And looking first at lines 18 and 19.

QUESTIONS FROM THE CHAIR

Q. Mr. Wiedmayer, this is perhaps for you. My understanding is that this -- the number that we see on that line, $385.2 million, that's the number that came out of the original Depreciation Study that you conducted for the annual depreciation and accretion expense?

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

Q. Okay. And it's my understanding that that number only includes the cost for partial decommissioning of hydro assets?

A. (Wiedmayer) Yes, that is correct.

Q. And it doesn't include decommissioning costs at all for Tusket, Mersey, or Wreck Cove?

A. (Wiedmayer) Also correct.

Q. And did you do an earlier version of the study that included full depreciation costs?

A. (Wiedmayer) Yes, that was one of

the alternatives scenarios that was presented to the company.

Q. Okay. And is that something that can be provided as an undertaking?

A. (Wiedmayer) Yes, sir.

Q. Okay. That will be Undertaking U-11.

UNDERTAKING U-11 - To provide the earlier version of the study that included full depreciation costs

THE CHAIR: And if we could go to now, Mr. Goodine, Exhibit 7, N-7, and page 142 of the PDF?

BY THE CHAIR:

Q. Mr. Wiedmayer, my understanding is this is -- well, this is coming out of your report that was filed in this proceeding, focused on the decommissioning costs, relating to the hydro plant in particular. A moment ago we mentioned that it only included partial decommissioning costs and not Tusket, Wreck Cove, or Mersey. The number that we see there for hydro plant, the 82.5 million, am I correct that that is the decommissioning cost that you included in the study?

A. (Wiedmayer) Yeah. The 82 million, if it could be -- could that be blown up onstream, that number?

Q. Yeah, we can do that.

THE CHAIR: Focus on the hydro plant numbers in the middle of the document there, Mr. Goodine.

MR. WIEDMAYER: Yeah, that 82 million is the current cost, yeah. If you can also, yeah, keep the heading on it, would be...

BY THE CHAIR:

Q. So the 82.5 million is the cost as of, I guess it was December 31st, 2023, if I recollect the date correctly for the study, for the partial decommissioning?

A. (Flemming) Mr. Chair, those would be the decommissioning costs in 2024 dollars.

Q. In 2024 dollars.

A. (Flemming) Yes.

Q. Okay, thank you.

THE CHAIR: Sorry, Mr. Goodine, if we could flip back to Exhibit N-3 again, page 40. Now, look at Figure 8.1. It continues on the next page if you could maybe scroll so you get both -- there we go.

BY THE CHAIR:

Q. Now, Figure 8.1, as I understand it, is what happens to the depreciation and accretion expense after the Settlement Agreement, and there’s a $20 million reduction and that takes into account the items that were noted in Appendix 8(g) to reduce that amount?

A. (Flemming) Correct, Mr. Chair.

Q. Okay.

THE CHAIR: And if we could go to Appendix 8(g), which is back in Exhibit N-7. Sorry for flipping you around so much, Mr. Goodine. Page 652 in the PDF. Sorry; I’m looking for 654.

BY THE CHAIR:

Q. Mr. Wiedmayer, this is the same table we looked at a moment ago, but now in the spreadsheet that relates to the updated decommissioning cost after the settlement discussion. And am I correct in interpreting this that that 89.5 figure that we looked at before as a result of the settlement negotiations, the decommissioning costs included in the updated numbers is now 29.4 million?

THE CHAIR: Might need to blow that up a little bit, Mr. Goodine.

MR. WIEDMAYER: And can you show the full column heading, please? Okay.

(SHORT PAUSE)

MR. WIEDMAYER: Yeah, I can see the amount. Just a little bit larger for -- if you can. And I would ask perhaps Mr. Flemming if...

MR. FLEMMING: Sure.

Just one moment, please, Mr. Chair.

(SHORT PAUSE)

MR. FLEMMING: You're correct, Mr. Chair.

BY THE CHAIR:

Q. And I assume, again, that's 2024 dollars, is it?

A. (Flemming) Yes.

THE CHAIR: All right, Mr. Goodine. If we could go back to Exhibit N-3, please? This time to page 44. And going to the bottom of the page, to the footnote.

BY THE CHAIR:

Q. Mr. Flemming, maybe I'll aim this one at you and you can deflect it, if you need to, somewhere else. But as I understand it here, this was a note that was provided for context from a comment that was made earlier on the page. There's a reference to full decommissioning costs estimated at 4.5 billion in total. That's Nova Scotia Power's current best estimate of full decommissioning costs for all of its hydro assets?

A. (Flemming) That is for those three systems in particular, the Tusket, Mersey, and Wreck Cove systems; that would be the total, and that would be escalated to future dollars, to the expected time of decommissioning.

Q. Oh, that's just those three systems.

A. (Flemming) Correct.

Q. Okay. So that's 4.5 billion for those. What's the current best estimate for the total, including the rest of the hydro facilities?

[9:10:12] **A.** (Flemming) Mr. Chair, I don't have the figures right now in future dollars. The amount in 2024 dollars for full decommissioning of all of the hydro sites would be approximately $3 billion is the best estimate. Nova Scotia Power engaged Hatch and Boreas, and they helped us inform those figures.

Q. Okay. So the 4.5 billion is --

sort of what vintage dollar is that?

A. (Flemming) Again, Mr. Chair, I apologize, I don’t have the dates readily in front of me. I believe that the vintage for those assets for Wreck Cove and Tusket would be in the area of around 2070, in and about that year.

Q. Sorry; I was looking for how old the estimate was, the 4.5.

A. (Flemming) Oh.

Q. My apologies.

A. (Flemming) Oh, sure. So that estimate would have been developed in 2024.

Q. Twenty twenty-four (2024).

A. (Flemming) Yes.

Q. And so for the total for all the hydro systems, do I add those two numbers together, the 4.5 and the 3?

A. (Flemming) No, the 3 billion would be inclusive of those three systems.

Q. Okay.

A. (Flemming) But again, in 2024 dollars.

Q. Okay.

A. (Flemming) So fair amount of impact of the inflation -- the expected inflationary impact out to the expected future decommissioning dates.

Q. Okay. All right. Thank you. In terms of the numbers, then, the 29.4 million that is included in decommissioning costs that are included in the proposed depreciation and accretion amounts in this rate case, it’s just -- it’s a fraction of 1 percent of what you estimate. And I just wonder if you can explain to me why -- I understand there’s questions around whether they will ever be fully decommissioned, but that seems like, you know, even taking that into account, a very small number, compared to the potential costs here. Can you kind of walk me through why that’s reasonable in the context of where we are now?

A. (Flemming) Mr. Chair, we believe that -- really believe that partial decommissioning is the most likely outcome for all of these systems at this time. There's no indication that full decommissioning, drawing down the waterways, returning to the natural state, would be possible or feasible in these cases. And so we have built in the partial decommissioning costs within the net salvage portion of the depreciation rates for all of the hydro systems, with the exception of the three that are noted within the Application. And we've outlined the reasoning for why we don't believe decommissioning of those three systems in particular will occur, or our best estimate at this time is that they will not occur.

Q. Mr. Williams, you had a discussion with Board Member Murphy yesterday about broader discussions that need to take place around this particular topic. My recollection was the timeframe of that was a little bit uncertain. Can you outline for me what Nova Scotia Power plans to do to bring that conclusion to a head or to get it to done so that this fairly significant uncertainty isn't out there for much longer?

A. (Williams) Yeah, absolutely, sir. So I think, as I had indicated in the discussion with Mr. Murphy, we see this process as kind of the first step in that. So I think coming out of this process, and certainly, you know, the next steps will be informed by the Board's decision, quite frankly, in this matter.

Assuming we stay on the path that's been proposed, what we would be doing is initiating that broader discussion. So I do believe that that is our responsibility to initiate that discussion. But the outcome of that discussion is not necessarily something that's within our control. The timeframe for that discussion is not something that's necessarily within our control. But as I said, we would be initiating that discussion.

So I think the first steps is

continuing the discussion that's already been initiated with the regulatory stakeholders and to get their input on that approach, and then it would be bringing the other very relevant stakeholders that I had listed off yesterday into the discussion.

Ultimately, the Province needs to be part of that discussion and will play a big part in that discussion. They -- we own the assets, but we operate them and hold them at the leisure of regulatory permits that are controlled by the government, and so they would need to be part of that. To the extent that it isn't ultimately Nova Scotia Power that owns those assets, if they were to be partially decommissioned, or responsible for the decommissioning, then the party who is going to be the owner is going to be responsible, and those instances would need to be determined.

So it is, as I said, a broad discussion. I don't know if I'm giving you a whole lot more today than I gave Mr. Murphy yesterday, sir, but certainly would acknowledge that it's our responsibility to bring that conversation forward. But I do want to make the point that we're not the only voice in that and we can't control the outcome of that.

Q. I appreciate the -- I appreciate the difficulties, Mr. Williams. If the Board, as you say, accepts what is proposed and puts you down -- or on that path you've just described, it would be reasonable, to your mind, would it, that the Board would require some regular reporting and monitoring of those discussions as they move forward?

A. (Williams) I would say absolutely, sir. And I think it would be helpful to have that type of accountability and expectation communicated from the Board.

Q. Thank you, Mr. Williams.

THE CHAIR: Mr. Goodine, if we could go back to page 41 in that same document and now looking at Figure 8.2.

BY THE CHAIR:

Q. Mr. Flemming, my understanding of sort of how we get from the $365 million figure, which was the one after the settlement discussion, to the $264.9 million figure is the assets that are going to be securitized are removed, in terms of adjustments to depreciation rates for those assets; is that correct?

A. (Flemming) That's absolutely correct.

Q. Okay. And if I'm interpreting the paragraph that follows below that table correctly, removing the existing depreciation embedded in rates for those assets removes another 26.6 million from that figure?

A. (Flemming) The -- what we're saying there is, taking those depreciation rates that apply to the balance at the end of December of 2023, taking those rates and applying them, we put those into our power plant software and we apply those to the gross book value of balances of all the individual asset classes monthly throughout that period as part of our forecasting process, and that would provide us with depreciation and accretion expense of $309 million in 2026 and 327.4 million in 2027.

However, by removing the gross book value of the assets within the scope of the DDA that we propose to securitize, by doing that, that would further reduce the depreciation expense by $26.6 million on an annual basis for the test period.

[9:20:00] **Q.** Okay. So the two adjustments, the one in Figure 8.2 and the 26.6 million, all relate back to the securitization of the DDA assets.

A. (Flemming) Correct. And the removal of that balance from Nova Scotia Power's rate base.

Q. Okay, thank you.

THE CHAIR: Mr. Goodine, if we can now go to Exhibit N-31, page 819 in the PDF.

BY THE CHAIR:

Q. This is the response that Nova Scotia Power provided to Emrydia, IR-27. It's the table that was reproduced in Mr. Madsen's evidence that we looked at yesterday. It's the numbers that were recalculated by Nova Scotia Power if the Average Life Group methodology were to be used.

THE CHAIR: Now, there's a comment on the previous page, if we could just go to that for a moment, Mr. Goodine, at lines -- it's in the last paragraph there.

BY THE CHAIR:

Q. It's the last part of the paragraph:

> Please note that the depreciation rates calculated under the Average Life Group use the same assumptions as depreciation rates calculated under the Equal Life Group in Appendix 8A and do not reflect the adjustments made per the consensus approach to the GRA.

So does that mean, if we go on to the

next table, if I want to compare apples to apples, the depreciation rates showing for the ALG procedure I shouldn't be comparing them to what's in the “Per GLA Settlement Agreement” numbers there, I should really be looking at the original Depreciation Study, which was the $385 million?

A. (Flemming) Not exactly. The 385 includes the change to the -- it includes the change to the rates associated with the assets within the scope of the DDA, whereas these figures here, per the depreciations calculated under ALG, would not. So it would be more apt to compare that to the 284.9 figure as opposed to the 385.

Q. So the numbers you do have here on this table, they're the appropriate comparisons that would be the net result of changing from the Equal Life Group to the Average Life Group methodology, taking into account all the adjustments made under the Settlement Agreement and the removal of the securitized assets?

A. (Flemming) So I would say that

the appropriate comparison, if you were looking for a pure comparison of the ELG methodology versus the ALG methodology, you would want to add the approximately $20 million reduction to the figures in the “Per Settlement Agreement” columns. So the adjustments we made per the Settlement Agreement would have removed approximately $20 million in each of 2026 and 2027 from the figures produced by Mr. Wiedmayer's work, so a pure comparison of ELG versus ALG, you'd be looking at more like 302.4 for the Equal Life Group in 2026, and 320.8, approximately, in 2027.

Q. Okay. So the sort of the net impact is approximately $20 million more between the two from the numbers that are showing in this table?

A. (Flemming) Correct. And so when you're looking at the -- if you're -- when you're looking to compare the two, you're looking at about 40 to $45 million, approximately, in the difference between ELG and ALG in any given year.

Just one moment, please, Mr. Chair. I'd like to confer with my colleague.

Q. Thank you.

A. (Williams) Sorry, Mr. Chair. Just this discussion prompted the previous undertaking in my mind that had been made to Mr. Mahody, and I think that undertaking should likely be revised to show the true difference with the $20 million added to the Per GRA Settlement numbers to show the true difference of the FFO-to-debt ratios.

THE CHAIR: Mr. Mahody?

MR. MAHODY: Well, I wonder if we could do it both ways so that we could see it. I appreciate the affect it will have, but I'd like to see it with and without.

MR. WILLIAMS: I don't think the way that it's been proposed currently with the undertaking will show an apples-to-apples comparison, that's why I'm suggesting the change.

BY THE CHAIR:

Q. Understood. Is it possible to do it both ways?

A. (Williams) I would hope so since we've already committed to doing it the initial way, sir, but ---

Q. Well, if you could it both ways, that would be appreciated. But I understand the comments about the one that you're talking about now may be the more appropriate comparison.

A. (Williams) Yes, agreed.

Q. Okay.

THE CHAIR: Yeah, I'm just going to try, just for the record, identify which undertaking that was if I can. You think it was Undertaking 7. I believe it was.

VICE CHAIR DEVEAU: Yeah.

THE CHAIR: Yeah. So that will be a revision to Undertaking 7.

MR. WILLIAMS: Thank you, sir.

UNDERTAKING U-7 - To also show the true difference with the $20 million added to the Per GRA Settlement numbers to show the true difference of the FFO-to-debt ratios

THE CHAIR: Mr. Goodine, if we could now go to Exhibit N-34, page 56 in the PDF. And just looking at the -- if you could get the full question and answer there on the -- there, that's good.

BY THE CHAIR:

Q. Mr. Wiedmayer, my understanding of this question and answer from Mr. Madsen's evidence that's appearing on the screen now from Exhibit N-34 is that he is suggesting that switching to the Average Life Group procedure would complement the ongoing payment obligations for securitized assets removed from rate base. I'm just wondering if you could comment on whether you see anything wrong with the logic that is presented in this response to this question in the evidence?

(SHORT PAUSE)

MR. WIEDMAYER: I can, yes. Mr. Chair, yes, as I read this response, I disagree with it. There will be a point at which there is a crossover that will take place, and I have models that demonstrate that. So Mr. Madsen says it's:

> highly likely that any future ‘cross-over’ point, where depreciation recovered under ALG exceeds the amount recovered under ELG, will occur decades if not centuries into the future.

[9:29:34] It’s true that early on in the assets’ life, the assets’ group life, that ELG rates, because of the way they calculate the depreciation over each equal life group, meaning each age within that asset pool, as we talked about mass property assets yesterday, like line transformers and poles, even though they have -- we use a survivor curve that indicates an average service life as well as a dispersion pattern, that dispersion pattern means that there's a range of service lives to be experienced by poles and line transformers. Some of the retirement causes for each would be caused due to third-party damage, storm damage. And as a result, these assets only are in service -- they can be retired as young as one-year old and they can be in service for much longer, beyond the average service life for poles. If we're saying the distribution poles have an average of 45 years there will be an expectation that some live beyond that average, 45 years, 60, 70 years, perhaps as long as 80.

So under the Equal Life Group procedure we set to statistically recover the cost of thousands of poles that are added each year. We know from a statistical probability that there'll be so many poles that live one-year old, so many that will live two-years old, three-years old, all the way up to 80. So the Equal Life Group does produce a higher rate earlier in the asset group's life, because what we do is then we composite all of those individual equal life groups, and the rate that we use under the Equal Life Group procedure would initially be higher than the Average Life Group. But there is a point at which the Average Life Group rate is higher than the Equal Life Group.

BY THE CHAIR:

Q. And I don't see Mr. Madsen's evidence as disagreeing with that point. I read this as him acknowledging that there is a crossover where the Average Life Group costs are higher than what would be under the ELG method later on.

I think what he's suggesting here, at least as I understand it, is that switching to the Average Life Group at this point in time could potentially make room for, in terms of what's currently in costs, dealing with the repayment of the securitized assets, at least in the nearer term, and perhaps accelerating that a bit depending upon the amount of room that's available. Is there anything wrong with that logic?

A. (Flemming) Mr. Chair, do you mind if I offer my thoughts?

A. (Wiedmayer) Yeah, go ahead, Mr. Flemming, yes.

A. (Flemming) If -- okay. Thank you. I appreciate it.

Mr. Chair, my thoughts on this are that I understand Mr. Madsen’s point. From my perspective, the Average Life Group -- and I’ve seen Mr. Madsen’s charts in terms of lower costs. My thought on it is that when we know that we have a certain dispersion, and we know that we have certain assets that are only going to last a specified period of time, Nova Scotia Power, by the nature of its business, and in fact all electric utilities, a lot of its assets involve like-for-like replacements.

And so what you have in an Average Life Group procedure is you have customers paying for assets that are -- if historical activity matches future activities, you have customers paying for assets that are no longer in service. Because you have that dispersion curve, as Mr. Wiedmayer just noted, you know that a certain amount of poles, for whatever reason, are only going to last five years as opposed to the average 40 years. And so it's fine when you structure it in the Equal Life Group you have the matching of that cost to that five years. And under the Average Life Group if Nova Scotia Power replaces that pole and the customers are paying for it over 40 years you have customers paying for 40 years for a pole that has only lasted five years.

In terms of Mr. Madsen's assertion in terms of making room for the securitization costs, my view is that any cost savings due to a shift to the average life group would be short term in nature. Nova Scotia Power, as Mr. Wiedmayer stated, has been on the Equal Life Group for over 30 years, and that has had a direct benefit to customers, and the reason for that is it has lowered Nova Scotia Power's rate base and therefore financing costs. If we were to switch to the Average Life Group absolutely we would see a reduction in depreciation expense, but that would be offset by increased financing costs.

Mr. Wiedmayer, I believe your firm has run some models around the timing associated with how long that might take to offset the savings from the Average Life Group, and I believe it is significantly shorter than the expected term of the securitization bond, but, Mr. Wiedmayer, if you'd like to expand on that, please, go ahead.

A. (Wiedmayer) Yes, the models that we have run generally indicates that that crossover will occur. As Mr. Flemming has pointed out, the use of the Average Life Group will result in lower depreciation expense in the short term, but lower depreciation expense, depreciation expense being a unique expense item, is that it also impacts rate base. Depreciation expense is a component of accumulated depreciation, which is a reduction to rate base. So the higher the accumulated depreciation from the use of the Equal Life Group the lower the rate base would be, and less return would be required on that rate base.

So Mr. Madsen's recommendation to use the Average Life Group only presents one side of the impact on the revenue; that is, you know, the depreciation expense will lower the revenue requirement if you switch to the Average Life Group. However, he's not presented what the impact would be on rate base. He has -- you know, if we had been using Average Life Group for the last 30 years the rate base today would be much higher than it is today. So he is presenting a scenario where the use of the Average Life Group results in lower depreciation by approximately 10 percent; however, the rate base -- he makes no adjustment to rate base, which is not the likely scenario had Average Life Group been in effect for the last 30 or more years.

So I believe that that presentation needs to have a *pro forma* adjustment to show the true impact of his recommendations. Meaning that the rate base would be much higher today had the Average Life Group procedure been in effect in Nova Scotia for the past 30 years.

So, in essence, he's recommending the Average Life Group as a revenue requirement component for the depreciation expense; however, the rate base has been built up through the use over the last 30 years using the Equal Life Group procedure. So he's using the best of both worlds. And, you know, I think that that presentation is lacking what the real impact would be to customers, in terms of the total revenue requirement, the depreciation expense plus the return on rate base. If you add those two up over time Equal Life Group procedure would result in lower -- a lower revenue requirement for customers in Nova Scotia.

Q. He also, I think, suggested that the impact of lowering rate base more quickly was a high motivator for utilities perhaps adding unnecessary costs to rate base. I take it you disagree with that?

A. (Wiedmayer) Yes, I do, in the sense that in Nova Scotia Power each year, there is a capital budget application, the Board has the opportunity to scrutinize the capital expenditures made by the company. I think that's a good process and I think it doesn't occur in every jurisdiction. So each year the company comes before the Board and presents a justification for their capital expenditures. I see that as a good process and I see that as, you know, a way that if what Mr. Madsen suggests is occurring, the Board can weigh in every year on that topic.

[9:40:25] **Q.** Sure, but the Board is never going to be in possession of the same information as the utility. The utility always has an advantage in terms of knowing its system and having the data to demonstrate all kinds of things, doesn't it?

A. (Wiedmayer) Well, maybe I'll ask Mr. MacIntosh or Mr. Flemming to weigh in on that. You know, in terms of what is presented at the capital budget application.

(SHORT PAUSE)

MR. FLEMMING: Thank you for your patience, Mr. Chair.

So I think first and foremost, Nova Scotia Power, in terms of the applications, its capital applications, its annual capital expenditure plan applications, the company does endeavour to provide as much information as possible to attempt to put the Board and customer representatives on an equal footing, or as close to an equal footing as possible, in terms of understanding the rationale for Nova Scotia Power's investment decisions. But your point is well taken. The utility will always have more information.

In terms of Nova Scotia Power being incented to make more capital investment due to a certain depreciation technique, I don't believe that to be true. Nova Scotia Power would always come forward with the investments that the company believes are appropriate to provide an appropriate level of service to customers while balancing affordability. And that has been the company's philosophy, using its asset management framework in order to propose those investments.

Mr. Madsen's thought on recovering the costs more quickly, incenting Nova Scotia Power to invest more, I don't necessarily follow the line of thinking there. While certainly it would increase Nova Scotia Power's cashflow by having a higher depreciation rate, you know, what he's saying is that, you know, on the other side, on the flip side, with the ALG there's a higher rate base, right, and therefore a higher return on that rate base.

And so I think from a utility perspective, I think that we're not in preference or one or the other. certainly, again, Nova Scotia Power's focus in determining its capital investment is providing an appropriate level of service to customers while balancing affordability.

Q. I just want to make clear, I thought I heard you just say a moment ago that you had no preference in terms of the ELG or the ALG method?

A. (Flemming) No, what I'm referring to is as a general theory in terms of what a utility might prefer. There's two sides to it, so one would be cashflow and one would be higher investment. From Nova Scotia Power's standpoint, we believe ELG to be appropriate and we believe that customers have directly benefited from Nova Scotia Power having that ELG in place, keeping our financing costs lower.

Q. Okay.

Mr. Wiedmayer, you said you had run a model that demonstrated this crossover point?

A. (Wiedmayer) Yes, I have. The question and answer that's presented here, I think I misread in terms of I thought the crossover that he was -- Mr. Madsen was speaking about was the impact on the revenue requirement, the total revenue requirement, which would include depreciation expense, plus the return on rate base. However, in reading this answer again, it seems like he's just speaking strictly to the depreciation expense crossover point between the Equal Life Group procedure and the Average Life Group procedure.

Q. Okay. And ---

A. (Wiedmayer) So I apologize if I misread the -- misunderstood his response here.

Q. Okay. And ---

A. (Wiedmayer) I didn't really have the context of, you know, earlier pages or whatever the questions were before this. So my apologies there if I read into it something other than what he's discussing here.

Q. No worries, Mr. Wiedmayer.

In terms of the model that you did reference that you had looked at, can you tell me what that model demonstrated?

A. (Wiedmayer) Yes, so we're looking at the total impact of -- on the revenue requirement between the Equal Life Group procedure and the Average Life Group procedure. So there's really two components that we're taking a look at, you know, excluding the tax impact. So it would just be depreciation expense between the Average Life Group and the Equal Life Group procedure, and what the impact would be on a rate base of those two different depreciation calculation procedures.

So I would agree in this case, for Nova Scotia Power, the Average Life Group results in a 10 percent lower depreciation expense under the Average Life Group procedure, which would be, you know, roughly, in my report calculation, with the numbers that I had presented in the report, about a $35 million reduction. Now, that $35 million reduction is what would be booked to accumulated depreciation. All the accruals that you would charge for depreciation expense get recorded to accumulated depreciation, and that accumulated depreciation is a reduction to rate base. So if it's 35 million in year one, it's 70 million in year two, and 105 million in year three, and so on and so on, to the point where that 105 million reduction to rate base in year three, you know, will grow to 350 million reduction in year 10, and I'm not even taking into account the growth in the gross plan service. So it's $350 million after 10 years using simple math and not -- you know, very simplified assumptions in this example. It would be -- you would reach 350 million probably in 8 or 9 years rather than 10 years. But $35 million each year you would reach a $350 million reduction to rate base and depending on what the return on equity and the weighted average cost of capital is, there's a point at which the total revenue requirement of depreciation expense and the return on rate base between the two procedures can be compared. And I'm saying my model demonstrates that between, you know, 8 and 15 years there's a crossover, and, you know, it varies based upon, you know, the return established in each jurisdiction as to when that crossover occurs. However, Nova Scotians -- Nova Scotia Power has been using Equal Life Group for over 30 years so, you know, I am confident that that crossover has occurred.

[9:50:50] **Q.** Okay. So if I understand the essential point though it's that the crossover, once you take into account the return on rate base impacts, occurs much earlier and I assume also end up paying more overall in the long term. Is that the end conclusion there?

A. (Wiedmayer) Yes, the end conclusion would be when you look at the total revenue requirement from depreciation expense and the return on rate base, so if we're assuming that the Average Life Group results in, let's say, $35 million less than the Equal Life Group, if rate base is 350 million less 10 years out, and let's just say we're using a 10 percent return on that rate base, you could see that at that point there would be a net effect of zero, in the sense that depreciation expense is 35 million lower under ALG but rate base is 35 million higher. So that's where the crossover would take place, you know, based on a 10 percent return on rate base.

And then in year 11 when it's $385 million less to rate base, then a 10 percent return on 385 million of a higher rate base would be 38.5 million as the return component versus a $35 million reduction to depreciation expense.

So you could see that over time there is going to be a crossover, and I think Nova Scotians have benefited from the use of the Equal Life Group procedure being in effect for the last 30 or more years.

Q. And the model that you prepared, is that something that you can file?

A. (Wiedmayer) Yes, sir.

Q. Okay. So this is the model that, as I understand it, demonstrates the crossover point between the two methods, the ALG and the ELG method, taking into account both depreciation effects and rate base effects?

A. (Wiedmayer) Yes, that's what the model would demonstrate, yes.

THE CHAIR: Okay. So that will be Undertaking U-12.

UNDERTAKING U-12 - To provide the model that demonstrates the crossover point between the ALG and ELG methods taking into account both depreciation and rate base effects

MR. MAHODY: Mr. Chair?

THE CHAIR: Yes.

MR. MAHODY: Given the nature of that undertaking, and the fact that it relates to a document that has already been prepared and is in existence, I wonder if Mr. Wiedmayer might be able to promptly provide that sometime, for instance today, so that it could be used in the current hearing.

BY THE CHAIR:

Q. That's something that you've already prepared, I understood, Mr. Wiedmayer?

A. (Wiedmayer) Well, we have prepared it for other clients in different jurisdictions, and, you know, the return component I would say would be applicable to that case. So I would need to do some adjustments for the current proceeding here in Nova Scotia Power, depending on what, you know, return component is acceptable or ---

Q. I think it would be helpful to have that in hand before Mr. Madsen testifies. So is that something -- assuming I think we're getting close to the end of your testimony here this morning -- that you could produce later today?

A. (Williams) Perhaps, if I may, sir, we can maybe communicate with Mr. Wiedmayer when we get off and come back with an update to the Board. But understood the desire to have it before Mr. Madsen appears. Based on my rough understanding of the timing, that's likely the beginning of next week.

Q. Things seem to be moving along a little faster than I had anticipated.

A. (Williams) That's music to my ears, then, sir. So we'll -- we can maybe touch base on the break with him, if that will be okay.

Q. Yeah, I mean I think today would be -- I suspect there's probably a good chance he may be ---

A. (Williams) We will do everything we can to keep things moving.

Q. Okay. I will, as I said, mark that as Undertaking U-12, and we'll -- you can discuss with Mr. Mahody the timing of that, but, yes, today would be appreciated.

THE CHAIR: Mr. Goodine, if we could go to page 113 in the document you're in now, PDF 113.

BY THE CHAIR:

Q. Mr. Flemming, Mr. Madsen here is recommending that the Board require a reconciliation of net salvage and actual salvage costs here as part of the next Depreciation Study. Is that something that Nova Scotia Power is prepared to do?

A. (Flemming) Mr. Chair, so what he's asked for here is since the date that the assets were installed. In some cases we have assets that are about a century or more old, and Nova Scotia Power has really had a fixed asset system that it can pull data out of that was -- we've talked about this before. We've had that in place since approximately 2009.

Q. M'hm.

A. And so unfortunately a year-by-year reflection and showing what we have year by year over the time period for each and every asset since it's been installed, I don't believe Nova Scotia Power has the capacity to do that. What we could do is certainly provide a schedule from 2009 onward.

Q. Okay.

THE CHAIR: Mr. Goodine, if we could go to page 68 PDF. And just the last question on the page there. And I don't think there's anything on the next page. Can you just flip over to check? Yeah, okay.

BY THE CHAIR:

Q. This is another recommendation for data production from Mr. Madsen. He's asked that certain information be provided with the Depreciation Study next go around rather than provide it in an information request response. He's got the five items there. Does Nova Scotia Power have any objection to producing that with the next Depreciation Study?

(SHORT PAUSE)

MR. FLEMMING: Mr. Chair, I believe that that would be reasonable, but I just ask, if you don't mind, Mr. Wiedmayer to just confirm that the -- that he doesn't see anything there that would cause him any concern.

[10:00:02] **MR. WIEDMAYER:** Yes. Mr. Chair, I think these five items are fine. The only thing that -- we touched upon this yesterday in terms of the peer analysis relied upon by the company in an Excel file.

So you know, what -- the way that we use industry data, in terms of what other electric utility companies use for their survivor curve, average service life, dispersion curve, and net salvage parameters, we use it more as a reasonableness check and not really as a -- in substitution of the company's life and net salvage analysis based on their own historical data. I'm just -- I would be a little concerned when I read into E, that there is some form of analysis that we rely upon, based on the estimates that are used by other utilities which we may or may not have any information how they determined their average service lives and survivor curves and net salvage percents.

There's enough differences in terms of accounting policies, maintenance practices, capitalization policies, differences in geography and climate that make a direct comparison with other utilities problematic, in my view. I would rather, you know, utilize industry data as a reasonableness check, rather than any type of reliance or substitution for the life analysis and salvage analysis performed using the company's specific historic data.

BY THE CHAIR:

Q. Okay, fair comment. But to the extent that you've relied upon some sort of industry or peer data for a reasonableness check, you would have no objection to including that as a schedule or an appendix to the study?

A. (Wiedmayer) That's correct, Mr. Chair. I would think that would be the most appropriate use of industry data.

Q. Okay. Thank you very much, Mr. Wiedmayer.

THE CHAIR: And those are my questions for the panel. I'll just go back around to see if there is anything arising from Board questions.

Consumer Advocate?

MR. ROBERTS: Nothing.

Thank you.

THE CHAIR: Small Business Advocate?

MS. MacADAM: No questions.

Thank you.

THE CHAIR: Affordable Energy Coalition?

Industrial Group?

MS. RUBIN: No questions.

THE CHAIR: Municipal Electric Utilities?

MR. MacDUFF: Nothing.

Thank you.

THE CHAIR: Natural Forces?

Nova Scotia Department of Energy?

MR. BOYLE: Nothing.

Thank you, Mr. Chair.

THE CHAIR: Port Hawkesbury Paper?

MR. MacDOUGALL: Nothing, Mr. Chair. Thank you.

THE CHAIR: Renewall?

MR. ROSCOE: Nothing from us. Thank you.

THE CHAIR: Did I miss anybody? Board counsel.

MR. MAHODY: Thank you, Mr. Chair. Just a couple.

THE CHAIR: Okay.

FURTHER CROSS-EXAMINATION BY MR. MAHODY

Q. In relation to Undertaking U-12, I believe is the number that -- the model undertaking, Mr. Wiedmayer, that you had just provided, I take it that the format of that model, it will be produced in Excel format?

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

Q. And I think in your testimony, Mr. Wiedmayer, you'd mentioned a number of -- a reduction of $35 million being an input into that model. As I understand Mr. Madsen's evidence, and the confirmation from the company regarding the effect of his recommended method change in 2026, for instance, is $23.7 million?

A. (Flemming) Mr. Mahody, maybe I can ---

Q. Yes, thank you very much.

A. (Flemming) --- address? The change between ALG and ELG, the ALG would be a reduction of about 40 to $45 million per year. If we're comparing the ALG that would be produced by Mr. Wiedmayer to what was agreed to by Nova Scotia Power and customer representatives in the Consensus Agreement, then I would agree with your figure.

Q. So Mr. Wiedmayer, will your model allow for an adjustment of those two different scenarios?

A. (Wiedmayer) I think it could be possible as long as we could specify -- well, not in a timely manner, I don't think. I think the model that I could provide in a timely fashion has already been developed using some parameters, in terms of the gross book value and the growth rate.

And so Mr. Mahody, I think we could present it, but not today. I mean, what I could present today is a model that we have presented in other jurisdictions that would be more of a generic calculation to demonstrate that there is this crossover with regard to the total revenue requirement between depreciation, expense, plus the return on rate base, that the sum of that would be the total revenue requirement impact of the depreciation recommendations between the two calculation procedures. So it's a generic model that I have. I don't think I could provide you anything today with Nova Scotia-specific calculations.

Q. Okay. Thank you, Mr. Wiedmayer.

MR. MAHODY: Mr. Chair, I'm content to rely on what gets produced today. If there's some interest, I think, that Mr. Madsen will have in reviewing that document, he'll do so.

BY MR. MAHODY:

Q. My only other point of clarification, Mr. Wiedmayer, I just wanted to make sure -- I'm going back to a conversation, questions you were posed to by Board Member Murphy yesterday.

MR. MAHODY: And Mr. Goodine, could we call up Exhibit N-34, page 83.

BY MR. MAHODY:

Q. And this is a Iowa curve for

transmission poles and fixtures. So you recall being referred to this figure yesterday during your testimony, Mr. Wiedmayer?

A. (Wiedmayer) Yes, Mr. Mahody.

Q. Okay. And am I reading the chart correctly that the black squares that are depicted here, those -- that data was derived based on simulated retirement data. Is that correct?

A. (Wiedmayer) Yes, that is correct. The simulated age retirement data was determined from the company's specific addition and retirement history from 1942 to 2023, as indicated in the upper right-hand box in that chart where the experience -- what we refer to in depreciation parlance is the experience band would include all of the fiscal years that make up this analysis.

So from 1942 to 2023, we have the addition in retirement activity for Nova Scotia Power that was unaged, and we have, using simulation techniques that are recognized within the electric utility industry, we have simulated those unaged retirements to produce simulated age retirements based upon a dispersion curve that's typical for this account. And once we have simulated aged balances and simulated aged retirements, we can analyze the data as if we had actual aged data for that period.

Q. And based on that ---

A. (Wiedmayer) And what this ---

Q. Sorry ---

A. (Wiedmayer) Yeah, go ahead.

Q. --- to interrupt, sir. I thought you ---

A. (Wiedmayer) I was going to say what this chart shows is, to me, is that there's been increasing levels of retirement in recent years since the last Depreciation Study. You know, one of the causes of retirements that came to mind yesterday when I was showing this chart was the storm damage from increasing tropical systems, as well as some other, you know, weather impacts, storm damage.

[10:10:06] I had performed this study in 2003 and another party, I believe representing Consumer Advocate, wanted to tour the facilities throughout Nova Scotia Power, and he was a consultant from Washington, D.C., and he arrived late September. You know, Washington, D.C., the climate’s different than Nova Scotia Power. So he was skeptical that, you know, any -- there’d be any climate impacts to the transmission and distribution assets. Well, he arrived the day before Hurricane Juan hit Nova Scotia Power. And, you know, obviously a large part of the province was affected by that, and electricity was off in certain parts of the province. And then I was also made aware of what’s known as White Juan, you know, the large storm damage caused by a winter storm that was quite substantial in that following period. So it seems as though more and more impacts of tropical systems hit Nova Scotia than perhaps in the past.

So when I look at this data, there is

-- definitely has been, since the 2009 study, an increase in the level of transmission pole retirements that have caused the average service life to be less, to be reduced from what I had originally estimated at 47 years. The 45 years that I'm recommending in this study is kind of a gradual reduction. What really would be the best fit Iowa Survivor Curve here would be something that I would imagine is in, like, the 41- to 42-year range, which I thought that would be too drastic of a change, and perhaps a 45 would be more appropriate, you know, given that the company -- a lot of the poles that are in this account, 355, are wood poles, H-frame structures that support, you know, the 138 kV system. So, you know, in addition to storm damage, there are other retirement causes that, you know, impact the level of retirements that the company is experiencing.

Q. So Mr. Wiedmayer, I'm going to take that as a yes to the fact that the black squares depicted in the figure were derived based on simulated retirement data. And then I take it ---

A. (Wiedmayer) Yes.

Q. --- having looked at that, you came to the conclusion, as demonstrated here, that the best match for this was the Iowa Curve 45R1.5; correct?

A. (Wiedmayer) Yes.

Q. Okay. Could we now turn to Exhibit N-34(viii)? That's Exhibit -- an exhibit to Mr. Madsen's evidence 8, which is the Newfoundland Power Depreciation Study that you had performed, Mr. Wiedmayer. And it's page 148 of this document.

MR. MAHODY: And if we could turn -- yeah, thanks very much, Mr. Goodine.

BY MR. MAHODY:

Q. And so now this chart, Mr. Wiedmayer, can you confirm that this chart depicts the life curve for Newfoundland Power accounts 355.01 and 02, which is generally the same account that was depicted in the previous figure we were looking at?

A. (Wiedmayer) Yes, the Iowa 52S0.5 is the Iowa Survivor Curve that I had recommended for transmission poles for Newfoundland Power.

Q. And the -- in Newfoundland, you were utilizing actual retirement data; is that correct?

A. (Wiedmayer) That’s correct. Actual aged data. It’s not like I created out of whole cloth data for Nova Scotia Power. It is still actual Nova Scotia Power addition and retirement data; it just does not have a record of when that pole was originally installed. However, every transmission pole in Nova Scotia Power has an installation date and a retirement date, it just hasn’t been recorded. It’s occurred. And the simulation techniques that are used to describe the average service life, which is a recognized technique known as computed mortality, was used to determine the simulated aged balances and retirements.

Q. Okay. But in Newfoundland, Mr. Wiedmayer, you did not rely on simulated plant records.

You had actual data; correct?

A. (Wiedmayer) Yes, we had actual aged data.

Q. Okay. And the conclusion ---

A. (Wiedmayer) But we have actual data in Nova Scotia as well. It's just not aged.

Q. And the -- your conclusion for these transmission poles and fixtures in Newfoundland was that the Iowa 52S0.5 was the appropriate curve in that case; correct?

A. (Wiedmayer) Yes, that's correct. You know, there are numerous factors that go into that selection. You know, one of it being the historical life analysis, and the other is that I had mentioned that we have detailed interviews with the engineering team at Newfoundland Power, as well as in Nova Scotia Power with Mr. MacIntosh and his team. And you know, clearly here, as you can see with Newfoundland Power, their retirement experience supports a 52-year average service life, which was consistent with the outlook and expectations of the engineers at Newfoundland Power.

Q. But Mr. Wiedmayer, you agree, don’t you, that if you had actual retirement data from -- aged retirement data in Nova Scotia, that the curve may, it’s within the realm of possible, the curve may have looked closer to the curve that you calculated in Newfoundland? That’s within the range of reasonable outcomes, isn’t it?

A. (Wiedmayer) Well, I disagree with that premise. and let me just explain why. I mean, certainly, it’s within the range of possibilities. However, not every electric utility in Canada and the United States use a 52S0.5. And I want everyone in the room to recognize that each electric utility has its own unique survivor characteristics due to the variety of reasons that I had mentioned, in terms of differences in capitalization policies, differences in maintenance practices, difference in the type of structures that are in some of these accounts.

So just because one utility uses one Iowa curve doesn't -- is not a reason to substitute it for another. What I would say is that in this account, transmission poles and fixtures, if we're looking at wood poles, I would say that the range of reasonableness, in my mind, is from -- probably from 45 years to 55 years as an average service life. Nova Scotia would be at the lower end of that reasonable range. I mean, that doesn't mean that there aren't any that use something less than 45; there are. It's just in terms of, like, the typical range of what I would expect to see would be -- would fall within that 45- to 55-year range for wood poles.

Q. But Mr. Wiedmayer, you cannot rule out that actual aged data, if it had been available in Nova Scotia, may have looked somewhat like what you observed in Newfoundland, can you?

[10:19:58] **A.** (Wiedmayer) Yes, I can. I'm sorry to disagree with that premise, because it's an incorrect premise. We're using actual data from Nova Scotia Power. It just does not happen to have a birthdate. Well, we know when it was installed. We just don't know when the retirements that occur, what year they were related to. However, based upon the addition and retirement pattern, and the simulation that was used, the simulation is really just trying to place a reasonable age on the retirement that did occur, and the retirement that did occur is a function of when that pole was installed.

So there is a definite survival pattern in Nova Scotia pattern -- in Nova Scotia Power that is different than what has been experienced in Newfoundland Power, and I'm sure what has been experienced in other provinces within Canada.

So it's not the fact that actual aged data was used in Newfoundland Power that makes it superior to the data that was used in Nova Scotia Power. We're using actual data for Nova Scotia Power, it's just that the retirements were not aged.

Q. They were simulated?

A. (Wiedmayer) They were simulated, correct.

Q. Those are my questions.

A. (Wiedmayer) And that simulation is based on a model of recognizing that every pole has a birthdate and an end date, and that we know when poles were added, and when poles -- we do know retirements have occurred and the simulation model then just kind of fills in the blanks.

MR. MAHODY: Thank you, Mr. Wiedmayer.

QUESTIONS FROM THE CHAIR

Q. I actually just have one follow up question from that, Mr. Wiedmayer. Is there anything that you're aware of from the preparation of your study in your report, and in particular, your discussions with the company officials that would account for why poles would not last as long in Nova Scotia as they do in Newfoundland?

A. (Wiedmayer) Yeah, as I mentioned, you know, earlier, with regards to industry data and peer analysis, I don't really look to other utilities and substitute their experience for the company that I am studying, their experience. I use industry data, the survivor curve and salvage percents that are used by other electric utilities more as a reasonableness check. Like, if Nova Scotia Power, if their poles indicated that they were only lasting 30 years, I would realize that that's outside the typical range for an electric utility and, you know, ask follow-up questions as to why that is. I don't really ask specifically, because I know there is a wide range of estimates that are used by other utilities. We could go through all the utilities in Canada and the United States, and I would say there would be many more that are different than Newfoundland Power than the same as Newfoundland Power, even though Newfoundland Power uses actual aged data.

I haven't done that comparative analysis, is what I'm saying. I used peer data more as a reasonableness check, rather than to compare and contrast and try and figure out, well, why is Nova Scotia Power -- you know, why are they shorter than Newfoundland Power? Because there might be some utilities where Nova Scotia Power is longer than other utilities.

Q. So your answer to the question, I think then, if I'm interpreting it correctly, is you're not aware of any reason why Nova Scotia Power's poles would have statistically shorter lives than in Newfoundland, a neighboring province with similar climate and geography?

A. (Wiedmayer) So my answer is that retirements are impacted by -- there's differences in capitalization policies, there's differences in maintenance practices, there's differences in the size of poles. I don't have all the statistics at hand. You know, perhaps there's differences in the classification of poles that are used. This account, transmission poles, for some utilities, and I would say most utilities, have a mixture of wood and steel poles. However, Nova Scotia Power, I would say the predominant material that's used in this account would be wood H-frame structures. And therefore, you know, wood doesn't last as long as steel, so if we were comparing Nova Scotia Power to another utility, let's say in Illinois, that uses primarily steel poles for their transmission lines, you know, they would probably have lives closer to 60 or 65 years.

So there's a variety of reasons why there are differences, and I wouldn't be able to chase down all of those differences that result in longer service lives in different jurisdictions.

Q. I'm not talking about different jurisdictions. I'm talking about Newfoundland, where you did a study. Do you know whether the poles they use are primarily wood poles?

A. (Wiedmayer) There's a mixture.

Q. Thank you, Mr. Wiedmayer.

THE CHAIR: Mr. Clarke, do you have any ---

MR. MacINTOSH: Mr. Chair?

BY THE CHAIR:

Q. Sorry?

A. (MacIntosh) Mr. Chair, ---

Q. Yes.

A. (MacIntosh) --- just to maybe put a pin on that, so Mr. Wiedmayer talked about multiple parameters that are different, that could be different. Nova Scotia Power, predominately in this account, has wood poles.

Q. Yes.

A. (MacIntosh) If you also look at the standing capital of what we're doing to upgrade our transmission systems; that's also a difference. It's also the difference on the type of soil that we have in Nova Scotia, versus the rock that would be in Newfoundland. So that goes back to the decomposition of a pole. There are many factors.

I just think the point we're trying to make here is utilizing the best information that we have, that demonstrates the actual data as best we have, is more appropriate than to utilize a different jurisdiction with different parameters. It's not an apples-to-apples comparison.

Q. Sure. Why would differences in your sustaining capital policies make for shorter lives in Nova Scotia?

A. (MacIntosh) No, just on what

upgrades would be occurring on the transmission system. So, say, if you did more upgrades, you would have a shorter retirement date. So if you did more -- you spent more on your transmission system and you upgraded poles. So the poles you're removing would have a shorter retirement.

Q. You're replacing poles before the end of their life more often?

A. (MacIntosh) Correct. With an upgrade, yes.

Q. Okay. Thank you.

A. (Wiedmayer) Yeah, capacity reasons, yeah, would be different from province to province and state to state, as Mr. MacIntosh has stated.

Q. Thank you.

__THE CHAIR:__ Mr. Clarke, anything arising from Board questions or re-direct?

__MR. CLARKE:__ No.

__THE CHAIR:__ Thank you.

Mr. Wiedmayer and the rest of the panel, thank you for your participation.

It’s the last we’ll see of you, Mr. Wiedmayer, so -- at least in this go around, so thank you very much for your evidence and your participation in this proceeding.

MR. WIEDMAYER: Thank you, Mr. Chair.

THE CHAIR: So we’ll get set up for the next panel.

It’s all in person, is it?

MR. CLARKE: It is. Mr. Chair, I appreciate this might be a little bit early, compared to other days, but I wonder whether we could take our midmorning break?

THE CHAIR: Sure.

MR. CLARKE: Appreciate that.

THE CHAIR: Yeah, so we’ll come back. It’s 10:30 now. We’ll come back at 10:45.

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

--- Upon resuming at 10:47 a.m.

THE CHAIR: Okay. Thank you.

Mr. Clarke?

MR. CLARKE: Mr. Chair, similar to yesterday, if you could swear in the panel and then I'll ask Mr. Coyne a few questions.

JIM COYNE, Solemnly Affirmed:

CRAIG FLEMMING, Solemnly Affirmed:

BLAKE WILLIAMS, Solemnly Affirmed:

MICHAEL WILLETT, Solemnly Affirmed:

EXAMINATION ON QUALIFICATIONS BY MR. CLARKE

Q. Mr. Coyne. Mr. Coyne, you are employed by Concentric Energy Advisers as Senior Vice-President?

A. (Coyne) Yes.

Q. Can you confirm that you have provided evidence in this matter on behalf of Nova Scotia Power that has been included as Appendix 10 to Nova Scotia Power's Application?

A. (Coyne) Yes. I provided this evidence with the assistance of my colleague, Mr. John Trogonoski, under my direction.

Q. And are you adopting that evidence as your evidence in this proceeding?

A. (Coyne) Yes, I am.

Q. Have you appeared before this Board or the prior Nova Scotia Utility and Review Board in the past?

A. (Coyne) I have. I provided evidence before the Board in Nova Scotia Power's 2012 and 2022 General Rate Applications. I also provided evidence on behalf of Eastward Energy in connection with its 2023 Cost of Capital Application and, most recently, in NSPML's 2026 assessment.

Q. Can you confirm that your professional qualifications and experience were filed with the Board in Appendix 10A, Section 1, "Introductions and Qualifications," and your CV filed yesterday?

A. (Coyne) Yes, they were.

Q. For the benefit of the Board and others present, can you please provide a brief overview of your professional qualifications and experience?

[10:49:51] **A.** (Coyne) Yes. I provide financial, regulatory, strategic, and litigation support services to clients in the natural gas, power and utilities industries. Drawing upon my industry and regulatory expertise, I regularly advise utilities, public agencies and investors on business strategies, investment, evaluations, and matters pertaining to rate and regulatory policy.

Prior to Concentric, I worked in senior consulting positions focused on the North American utilities industries in corporate planning for an integrated energy company and in regulatory and policy positions for the States of Maine and Massachusetts.

I've authored numerous articles on the energy industry and provided testimony and expert reports before federal, state, and provincial jurisdictions in both the U.S. and Canada.

I hold a Bachelor's in Science degree in Business from Georgetown University and a Master's degree in Resource Economics from the University of New Hampshire.

MR. CLARKE: Mr. Chair, Nova Scotia Power requests that Mr. Coyne be accepted as an expert witness in the areas addressed in Concentric's evidence, including cost of capital, rate of return, capital structure, business and financial risk, and economic factors that impact on regulated utilities.

THE CHAIR: Any questions or objections, qualifications?

He's so qualified, Mr. Clarke.

MR. CLARKE: Thank you, Mr. Chair.

The Cost of Capital Panel is ready for questions.

THE CHAIR: Consumer Advocate?

MR. ROBERTS: No questions.

Thank you.

THE CHAIR: Small Business Advocate?

MS. MacADAM: No questions.

Thank you.

THE CHAIR: Industrial Group?

MS. RUDDERHAM: No questions.

THE CHAIR: Municipal Electric Utilities?

MR. MacDUFF: No questions.

THE CHAIR: Department of Energy?

MR. BOYLE: No questions.

Thank you, Mr. Chair.

THE CHAIR: Port Hawkesbury Paper?

MR. MacDOUGALL: No questions, Mr. Chair.

THE CHAIR: Renewall?

MR. ROSCOE: No questions.

Thank you.

THE CHAIR: Anyone I missed before going to Board counsel?

Mr. Mahody.

MR. MAHODY: Thank you, Mr. Chair.

CROSS-EXAMINATION BY MR. MAHODY

Q. Mr. Coyne, good morning. Welcome back to Nova Scotia.

A. (Coyne) Thank you. Nice to be back with you.

Q. Even in January.

A. (Coyne) I've grown to like it.

Q. Try not to do anything at all to disturb that.

Mr. Coyne, you recall in your last appearances before this Board for Nova Scotia Power in September of 2022 that there was questioning by the Vice Chair of you regarding the history of the Fuel Adjustment Mechanism audit decisions. Do you recall a back-and-forth with the Vice Chair regarding history of the FAM?

A. (Coyne) I do.

Q. Okay. And ultimately in those discussions, you agreed that total disallowances arising from FAM audits up until September of 2022 represented

.019 percent of incurred fuel costs. Subject to check on the number, do you recall that exchange?

A. (Coyne) I recall the exchange. I don’t recall the number.

Q. Fair enough.

And since that time, Mr. Coyne, you’re aware that two additional fuel audit reports have been considered by this Board and have been the subject matter of detailed decisions that have been issued.

A. (Coyne) That is my understanding.

Q. Okay. I’d like to call up the Board’s decision for the 2020-2021 audit period.

MR. MAHODY: Mr. Goodine, I think I sent that document along to you.

BY MR. MAHODY:

Q. And so this is -- Mr. Coyne, just to orient you, this is the decision from Matter No. 100416 and if -- it’s for the fuel adjustment period 2020-2021, the audit report by Bates White.

MR. MAHODY: And if we could turn, Mr. Goodine, over to paragraphs 7 and 8 of this decision, please.

BY MR. MAHODY:

Q. I'll draw your attention to paragraph 7 where, ultimately, the Board makes a total disallowance -- at the bottom of paragraph 7, total disallowance of approximately $2 million.

And then in paragraph 8, to put this in context, the total disallowance of approximately $2 million plus interest, "is a very small fraction of the approximately $1.5 billion in FAM costs incurred by Nova Scotia Power" over the 2020-2021 audit period.

And from a percentage basis, subject to checking, perhaps, on your calculator, Mr. Coyne, you agree with me that represents 0.133 percent of total incurred fuel costs for that audit period.

A. (Coyne) Subject to check, yes.

Q. And you're aware that all of the

disallowances that this Board has directed in relation to the FAM have been disallowances on the basis of imprudence.

A. (Coyne) I'm not aware of the basis of each disallowance being on the basis of prudence.

Q. Okay.

MR. MAHODY: Mr. Chair, I don't intend to mark this Board decision as an exhibit.

If we could move on, then, to the next audit period, the 2022 to 2023 audit decision, Mr. Goodine.

Thank you.

BY MR. MAHODY:

Q. So Mr. Coyne, this is Matter No. M11533 for the 2022-2023 Bates White audit of FAM costs.

MR. MAHODY: And if we could turn over to paragraph 7 of this decision, Mr. Goodine.

BY MR. MAHODY:

Q. There's reference there to the

Trenton Unit 5 two boiler feed and, ultimately, down at the bottom of paragraph 7, the Board indicates:

> These extra costs were calculated at $1,141,261.58. The Board finds that Nova Scotia Power was imprudent and orders a disallowance of this amount, plus interest, to be credited to customers in the FAM.

Paragraph 8:

> To put this in context, the total disallowance, of approximately $1.1 million plus interest, is a small fraction of the approximately $1.7 billion in FAM costs incurred by [Nova Scotia] Power over the 2022 and 2023 audit period.

And again, subject to check, that disallowance calculates out at 0.0647 percent of total incurred cost during the audit period. Do you accept that.

A. (Coyne) Again I accept that, subject to check.

Q. And even with the benefit of the discussion that you had with the Vice Chair at the last hearing, and your awareness of these two decisions -- and I take it these decisions were made known to you shortly after they would have been released by the Board?

A. (Coyne) Correct.

Q. And even with the benefit of discussions with the Vice Chair at the last hearing and these two decisions, you continue in your report to conclude that the FAM represents a business risk to Nova Scotia Power.

A. (Coyne) That's correct. It's not just the FAM. It's the fact that it's a vertically integrated utility and it has the FAM mechanism associated with that.

Q. Okay.

A. (Coyne) And that distinguishes it from other utilities, in my experience.

Q. Fair enough.

Could we call up your testimony? It's Exhibit N-8, PDF page 98, please.

A. (Coyne) Did you say page 98?

Q. If you're looking at your paper

copy, I know is your practice, sir, it's at page 66 in the paper. It's page 98 of the PDF. And I'm at line 18 at the end of it, where you state, "We conclude that the design of NSPI's FAM, including the bi-annual audit and the associated regulatory lag,..."

A. (Coyne) I'm sorry, Mr. Mahody, I'm still not in your paragraph. Did you say page 66 as marked on the top of the page?

Q. No, I was looking at the bottom of the page for a paper copy but ---

A. (Coyne) Now let me get -- let me catch up to where you are. And you said you were on line 8?

Q. Eighteen (18).

A. (Coyne) Eighteen (18). Okay. I now see where you are.

Q. Thank you, Mr. Coyne.

> We conclude that the design of NSPI's FAM, including the bi-annual audit and the associated regulatory lag, translate into elevated risk on this factor relative to its

Canadian and U.S. peers.

And you have a footnote to that entry, and it's footnote number 92, and if we could just go down to the bottom of the screen you indicate that:

> Concentric understands that there were no disallowances from the 2016/17 FAM Audit and minor disallowances from the 2018/19 FAM Audit, and the UARB has recognized the maturing of the FAM Process. There was, however, a $4 million disallowance from the 2020/21 FAM Audit.

Do you see that?

[11:00:20] **A.** (Coyne) I do.

Q. Okay. Now, we just looked at the 2020-2021 FAM audit. It indicated a disallowance of $2 million. Can you explain what the basis is for your comment here that a $4 million disallowance was directed in the 2020-2021 FAM audit?

A. (Coyne) I would have to check that reference to see where that $4 million came from. I don't have it in front of me. Maybe my fellow panellists might know where the $4 million comes from. If it's from a different year I could correct that.

A. (Williams) Just one moment, Mr. Mahody.

A. (Coyne) One moment, please.

A. (Williams) Mr. Mahody, I believe that that is the interest impact that was -- it includes the interest impact that was also directed in that Board decision, subject to check.

(SHORT PAUSE)

BY MR. MAHODY:

Q. So, Mr. Flemming, is there somewhere you can check on that? Are you checking on something now, sir?

A. (Flemming) I'm trying, Mr. Mahody, but it's something I would have to confirm at a later time, I believe, at this point. But that is my understanding is that it is the interest impact included plus the -- the disallowance plus the interest is where the formula is coming from.

MEMBER DEVEAU: Sorry, Mr. Mahody. And I have actually prepared all those calculations if you want them. But anyhow, you've done a good job.

MR. MAHODY: I think right about now, Mr. Vice Chair.

MEMBER DEVEAU: I've got the totals. But it might be -- I didn't check the interest, because on those two decisions there was interest on those disallowances.

But just for Mr. Flemming and Mr. Coyne while you're checking that, if you look in paragraph 3 of that 2020-2021 audit there's actually a disallowance recommended by Bates White of 3.6 million, and I'm wondering whether that might have been used as a disallowance. But actually the Board only disallowed 2 million not 3.7 million.

MR. WILLIAMS: I think we'll have to take this away, unfortunately.

BY MR. MAHODY:

Q. All right. So perhaps an undertaking. If we could get the source of the $4 million amount referenced in footnote 92.

A. (Flemming) Yes, sir.

Q. Thank you.

THE CHAIR: It will be Undertaking U-13.

UNDERTAKING U-13 - To provide the source of the $4 million and the interest referenced in footnote 92 of Exhibit N-8

MEMBER DEVEAU: And the amount of the interest, Mr. Mahody?

MR. MAHODY: Yes, if ---

MEMBER DEVEAU: There was interest. So the amount of the interest.

BY MR. MAHODY:

Q. As part of the undertaking, Mr. Flemming.

A. (Flemming) Yes.

Q. Thank you.

Mr. Coyne, are you able to say that if it had been a $2 million disallowance, in your opinion, does that change your view that you've expressed here?

A. (Coyne) No, the view remains the same. And there are two distinguishing elements to Nova Scotia Power, as I see it from an investor risk standpoint. One, it's a vertically integrated utility that needs to acquire fuel, and that's a complex process involving financial markets and logistics that a pure T&D utility does not need to undertake. And secondly, because of its acquisition of fuel, it's exposed to the audit of those fuel processes. And again a T&D company or pure play company that's not exposed to that process doesn't have that same investment exposure.

And I would add that while your calculations of these numbers as a percentage of the total fuel cost may seem small it's much larger if you express it as a percentage of the net income of the company, and that's how an investor would experience such a disallowance.

Q. And in your -- you had provided that same comment -- a similar comment in 2022. And your report in 2022 had also made reference to the debt rating reports that you had relied on in saying well there is representation of this business risk being expressed there. Do you recall that?

A. (Coyne) I do.

Q. I'd like to show you what's been filed in this matter as the most recent debt rating -- the analyst reports.

MR. MAHODY: And, Mr. Goodine, if we could call up Exhibit N-27, page 490.

MR. COYNE: And is that S&P or DBRS?

BY MR. MAHODY:

Q. S&P is where we're headed.

A. (Coyne) And is it the most recent report?

Q. It's the most recent report that's been filed. And Mr. Flemming's about to tell me in a few minutes when I ask him if it's the most recent report that the company has.

So in this report from S&P January 28th, 2005 [*sic*] it indicates:

> Nova Scotia Power Inc. recently received a Canadian federal loan guarantee to securitize C$500 million of current and future fuel balances at NSPI: the company used the proceeds toward reducing debt at NSP. This follows the C$117 million NSPI received from the provincial government earlier in 2024 toward the deferred fuel cost recovery. S&P Global Ratings views these [as favourable] because they reduce debt at NSPI while also reducing the regulatory lag associated with recovery of higher fuel costs in Nova Scotia, which in recent years pressured NSPI's credit measures.

I'm wondering if in this document, and I think it just goes on for a period and you could take time to review it, Mr. Coyne, if you could indicate to me where S&P is saying that the design of the FAM translates into elevated business risks for NSP?

A. (Coyne) I don't see that in this specific report. If you turn to DBRS, however, they do mention the company's exposure.

Q. Fair enough.

MR. MAHODY: And that's at PDF page 477, please, Mr. Goodine.

BY MR. MAHODY:

Q. This is the DBR report, is it, Mr. Coyne?

A. (Coyne) Yes.

Q. Okay. And to begin with, you agree with me that DBRS highlights several positive developments under the key credit rating considerations?

A. (Coyne) Yes, they do.

Q. Okay.

MR. MAHODY: And if can scroll down, Mr. Goodine, to -- I'm at PDF page 480, under "Regulatory Lag".

BY MR. MAHODY:

Q. And here, DBRS says, under Item 5, "NSPI faces some regulatory risk with respect..."

A. (Coyne) I'm sorry. Where are you in the report?

Q. Okay. I'm at ---

A. (Coyne) Oh ---

Q. Yeah, at the top of the page. It's page 4 of 13.

A. (Coyne) I'm with you.

Q. Thank you:

> NSPI faces some regulatory risk with respect to the timeliness of fuel cost recovery, although this risk is lower now than when the FAM was not in place.

So I see that that's where DBRS is indicating that regulatory lag has actually been reduced because of the FAM. Where is it that you were making reference to them saying that this was a business risk?

A. (Coyne) If you turn to the

opposite page, paragraph 3, "Unfavourable Generation Mix". And maybe before I read their language, let me see if I can put this in perspective for the Board as I see it and how I believe an investor would look at it.

And that is that if -- as I -- and perhaps I'm just redoubling down on the comments I made previously, but if you are a vertically integrated utility you must acquire fuel for those resources, and if you have the asset mix that Nova Scotia Power has, that means that you're continuously in fuel markets, and as a result of that you have a different level of exposure than does a company that does not have those same obligations.

[11:10:09] **Q.** But that level of exposure, sir, is less with a FAM than it was without the FAM.

A. (Coyne) That's correct.

Q. Okay.

A. (Coyne) Yes. Prior to that, the -- as I understood it, the company only had the ability to recover fuel costs through a rate case application, so a

FAM is an improvement over that. But the FAM still -- as indicated here by DBRS, there is still a lag in terms of the timeliness of fuel cost recovery. Other fuel cost recovery mechanisms that I'm familiar with provide for a more immediate cost passthrough than does the FAM, so there is still some lag associated with it, and there's also a risk of disallowance.

A. (Williams) Mr. Mahody, could I add the company's perspective just briefly on this?

And Mr. Deveau, I'm trying to be responsive to the question that occurred in 2022 as well.

It's certainly not the company's perspective that the FAM creates the risk. It's not an absolute risk that exists as a result of that; it's a relative risk. So as Mr. Coyne's been explaining, the fact that Nova Scotia Power's is vertically integrated and has that fuel exposure, that creates the risk. Certainly, the FAM mitigates the risk, but the need for the FAM in general is what the -- what the risk presents.

So we -- it is by no means an intent to criticize the FAM or how it operates, it's just a reality of having that exposure to fuel. Certainly, the FAM mitigates it, as I said, but the risk remains because of the potential delay of cost recovery that doesn't exist for other utilities that are not vertically integrated.

MEMBER DEVEAU: Well, when you -- and Mr. Coyne, when you said that there is no -- there's not an immediate passthrough, actually there is because leaving aside when you have a large FAM balance, like you did in 2022, now is -- first of all, do you acknowledge now that the FAM balance is a lot less than it was in 2022?

MR. COYNE: Yes, sir.

MEMBER DEVEAU: Yeah.

MR. COYNE: It's been reduced.

MEMBER DEVEAU: Yeah. And so now in terms of fuel recovery, there is actually an immediate passthrough because Nova Scotia Power collects the fuel costs as set up in the base cost of fuel, and as will be set up when the base cost of fuel is readjusted in this matter, there is actually an immediate passthrough of costs. There's a truing-up later, but relatively speaking, Nova Scotia Power recovers its fuel costs immediately, doesn't it?

MR. COYNE: I think maybe a better way to express that is that there is a buildup in the FAM balance that I don't see with other utilities, and to a significant degree, and that's the lag that I believe that DBRS is referring to here.

MEMBER DEVEAU: But there -- the FAM balance is not like it was in 2022.

MR. COYNE: That's correct, it was not as large.

MEMBER DEVEAU: It's actually a credit when 500 million passed -- was approved last December, January. So the -- so Nova Scotia Power is collecting its costs. The only lag is that, and it's not really a lag;

they have to pay back what was not prudently incurred, but what they prudently incurred they get every time they send out a bill. Isn't that right?

MR. COYNE: I would defer to the company in terms of the mechanics of that cost recovery mechanism.

(SHORT PAUSE)

MR. WILLIAMS: Yeah, Mr. Deveau, I think in response to the question, the lag that's being referred to, I think is, as this is discussed, is in relation to the AA/BA and any over recovery/under recovery, that's the balance that would lag or the recovery that would lag. I certainly take your point that the base cost of fuel is intended to recover the true costs of fuel and power.

I think the point again is that that balance has, and to your point as well, historically (inaudible due to mumbling) has been a large balance. The FAM is intended to work on an annual basis and eliminate those balances, and I think it was established in that manner appropriately.

I think more recently because of the types of extreme volatility we’ve seen in fuel, the annual nature of that has exposed customers and the utility to larger balances than were maybe expected or intended. Certainly in other jurisdictions there is a more regular drop of those costs, and when I say more regular I mean more than annual, so quarterly, or in some jurisdictions it's if you're off forecast by plus or minus 10 percent, then it's an automatic adjustment. So there's aspects to it like that.

But again, we don't see this in raising this as a risk is necessarily a criticism of the FAM; it's just because of the need for the FAM, the risk exists because we're dealing with fuel costs which are recognized to be volatile, and there is perhaps not a perfect way to address those because of that volatility. The FAM certainly, as I said, mitigates or reduces that risk, but the fact that we need to even address it in the first place is evidence of the risk.

MEMBER DEVEAU: Are other jurisdictions, do they -- there is an opportunity to audit the FAM expenses, isn't there?

MR. COYNE: Yes, there's always the opportunity to audit fuel and all other expenses.

MEMBER DEVEAU: So generally, it is true, isn't it, that the companies -- the utilities get to keep their prudently incurred costs, but don't get to recover their imprudently incurred costs?

MR. COYNE: That's correct.

MEMBER DEVEAU: Right.

MR. COYNE: Yeah, right. And I should note that while we point this out as a risk associated with Nova Scotia Power as a vertically integrated utility, that we make no adjustment in our cost of capital analysis for that difference in risk. So the analysis that we've conducted here is based on a vertically integrated proxy group. All the companies in this proxy group that we rely on that are vertically integrated also have fuel cost recovery mechanisms. So we've made no adjustment to our cost of capital analysis for any distinguishing differences between NSPI's cost recovery mechanism and these other utilities. They do differ utility to utility, but there is no adjustment in the analysis for it.

MEMBER DEVEAU: But when you summarize -- when you summarize the various risks in your report, you specifically mention the FAM. So why would you specifically mention the FAM if -- so you're saying they're not -- they are determinative of the comparators, your companies in your comparator group that distinguishes Nova Scotia Power from your comparator group? Or you're talking about utilities generally?

MR. COYNE: No, the comparator groups. And here I'm talking about both Canadian and U.S. peers. Insofar as Canadian peers go, Nova Scotia Power is unique. It's the only fully vertically integrated company of its type that operates in Canada. So there's no other utility in Canada that needs a FAM the same way that Nova Scotia Power does. So that's distinguishing.

When we turn to the U.S. peers that do require large amounts of fuel, as does Nova Scotia Power, they have -- in my experience, they have fuel cost recovery mechanisms that clear either quarterly or annually. And I'm not aware of any utility in either jurisdiction that's accumulated such a large FAM balance as has Nova Scotia Power. And that's a distinguishing element.

[11:20:00] **MEMBER DEVEAU:** Right. Except that that large balance has been addressed with the cooperation of both the provincial and federal governments; correct?

MR. COYNE: Yes. And I ---

MEMBER DEVEAU: Because you note ---

MR. COYNE: I account for that in our report.

MEMBER DEVEAU: You do. You do. You

note -- I think it's DBRS. You note their comment and how the DBRS report quoted in your report mentions the 117 million and then you follow that with your comment that later the 500 million was provided to address the remainder of that balance.

MR. COYNE: That's right.

MEMBER DEVEAU: Right.

MR. COYNE: I see these as improvements, the same way that the credit rating agencies do. It's a reduction in debt and it addresses a significant issue on the company's balance sheet. And I would assume that that's something -- I wouldn't assume that it would be something that it would rebuild in the same way on a going-forward basis.

MEMBER DEVEAU: Thank you.

Sorry, Mr. Mahody.

MR. MAHODY: Thank you, Mr. Vice Chair.

BY MR. MAHODY:

Q. Mr. Flemming, back to the point about the DBRS and S&P reports. We have them -- the ones that have been responded to by way of an IR request. Have there been updated reports received by the company from those entities since those?

A. (Flemming) Mr. Mahody, the annual reports from DBRS and S&P, to my knowledge, have not yet been published.

Q. And do you have an expectation as to when they will be published?

A. (Flemming) Generally would be in the same timeframe. So as you see that the DBRS -- excuse me, the S&P report that we just looked at was published on January 28th of 2025, I'd expect both DBRS and S&P at the latter part of this month.

Q. Mr. Coyne, I'd just like to turn to your report and confirm a couple of adjustments, as I understand them, on the record of the proceeding.

If we could call up Exhibit N-8,

Appendix 10(a), your report; it's Figure 24. It's on page 49 of 87, I have, Mr. Coyne, if -- the paper copy. And it's PDF 76. That's where I'm going.

And in undertaking this CAPM analysis, Mr. Coyne, I'm correct that Concentric has used the average of Canadian and U.S. MRPs?

A. (Coyne) That's correct.

Q. And using historical Canadian MRPs in the CAPM would produce a result including flotation of 9.06 percent?

A. (Coyne) How do you get that number, Mr. Mahody?

MR. MAHODY: Can we call up N-27, IR-109, please, Mr. Goodine?

(SHORT PAUSE)

MR. COYNE: Yes, I see that response, Mr. Mahody.

BY MR. MAHODY:

Q. And so that's the result of -- or to utilize the historical Canadian MRP, including flotation, adjust your number to 9.06 percent?

A. (Coyne) That's correct.

MR. MAHODY: While we're in these IRs, could we turn up IR-108? It's at page 504.

BY MR. MAHODY:

Q. And here you were asked to confirm if Canadian utility results are heavily influenced by Enbridge, which you make reference to at page 41 of 87 of your report. And it has a significant increase in its payout ratio. And it goes on -- the IR goes on to request that:

> Please confirm, or explain otherwise, that excluding Enbridge...from the Canadian Utility results...a Multi-Stage DCF result of 9.13% (including 'flotation costs and financial flexibility'.

And you've responded. We see response to (a) is "confirmed" and (b) is "confirmed".

That accurately represents the consequence of removing Enbridge from your analysis?

A. (Coyne) Well, from the Canadian utility group.

Q. Yes.

A. (Coyne) That's not -- that is not the proxy group that I've relied on for my primary analysis, which is the North American proxy group. So if you remove it from the Canadian utility group that I have not primarily relied on, yes, that's the impact.

Q. Okay. And I do have some questions for you about the reliance on the U.S. data in just a moment, but just before I do that, could I take you, in the same IR responses to page 511 in the PDF? And I'm going to get you an IR number in just a moment, Mr. Chair -- Mr. Coyne.

Okay. And it's down at -- so it's Board IR-113, and it's the answer to (c). And at line 18, you indicate, "...the Bank of Canada's preferred measure of inflation is CPI Trimmed mean."

Do you see that?

A. (Coyne) Yes, I do.

Q. Okay. And you'll recall, Mr. Coyne, when we last interacted back in the NSPML assessment hearing in December, I had asked you about whether the Bank of Canada's preferred measure of inflation was indeed CPI Trimmed, and you confirmed that it was.

A. (Coyne) I did.

Q. Okay. I'd like to call up a document and have you -- give you a chance to look at it.

MR. MAHODY: Mr. Goodine, it's the October 2025 speech delivered by the Deputy Bank of the Governor -- Deputy Governor of the Bank of Canada.

BY MR. MAHODY:

Q. And so Mr. Coyne, just to orientate you, Mr. Mendes is the Deputy Governor of the Bank of Canada, and this is a speech that is housed on the Bank of Canada website. It was delivered at the Ivy School of Business in Queens on October 2nd, 2025. And it's entitled, "Underlying Inflation: separating the signal from the noise." And I'd like to take you over to page 3 of this document.

A. (Coyne) Can we expand the document on the screen? Thank you. That's better.

<u>MR. MAHODY:</u> And it's over at page 3 of the PDF, just under -- near the bottom of this page, please. So -- yes. Thank you, Mr. Goodine.

<u>BY MR. MAHODY:</u>

Q. So it's the paragraph that begins with:

> From 1991 to 2016, our primary gauges for core inflation simply excluded a fixed set of volatile components. Then, in 2016, we embraced a more dynamic and flexible approach. We adopted a trio of preferred core measures...

The CPI-trim, CPI-median, and CPI-common.

[11:30:00] It goes on to say, "These measures served us well in the pre-pandemic period."

So just to pause there, you don't take any disagreement with the Deputy Governor of the Bank of Canada regarding what they were using between 1990 -- beginning in 2016 about those three preferred measures, do you?

A. (Coyne) No.

Q. Okay. He then goes on to say:

> These measures served us well in the pre-pandemic period. However, as inflation surged after the pandemic, CPI-common became difficult to use in real time due to unusually large historical revisions. That's why, in 2022, we stopped [using] CPI-common in our set of preferred measures.

MR. MAHODY: If we could go to the next page?

BY MR. MAHODY:

Q. "And while our remaining two preferred measures have generally been helpful, they were less reliable during some periods."

So do you agree with me that at least as of the fall of 2025, CPI-trimmed was not the preferred measure of inflation for the Bank of Canada?

A. (Coyne) In other publications I see the Bank primarily referring to CPI-trim as their preferred measure. I realize that they still look at three, but CPI-trimmed has evolved, in my reading, to be their preferred measure. But the difference between CPI-trim and CPI-median -- if we go up to the chart, if we can just flip up a page, you'll see all three charted together. And you can see what they're trying to do with -- by removing -- with CPI-trim or SPI-median, is to remove the impacts of, let's just say, for example, groceries go up by an extraordinary amount due to an agricultural issue, they're trying to remove -- or fuel costs go up due to a disruption in fuel supply. They're trying to remove that effect from the total CPI. And you could do that either with CPI-trim or CPI-median. I believe that, from my reading, CPI-trim has evolved to be the primary measure. But either one is going to tell you a similar story. It's CPI that's the problem, not CPI-trim or CPI-median. The U.S. Government has taken a similar approach, as they recognized that CPI has a basket of goods and it can send you a signal that's not altogether accurate if you have some outliers in that mix.

Q. But in your report, Mr. Coyne, and in previous reports, you've indicated a single preferred measure of inflation by the Bank of Canada. and here's the Deputy Governor of that bank saying we have two preferred measures, and that, in effect, I put it to you you're wrong in saying there's a single preferred measure.

A. (Coyne) Well, in my reading, CPI-trim has evolved to be the primary measure. This is one report. We look at them as they come out, and we continuously see CPI-trim over the last several years as being the primary focus of the bank.

Q. And you maintain that view, even having now reviewed the documented comments of the Deputy Governor of the Bank of Canada?

A. (Coyne) Well, I take his comments as being as they were. I don't see a meaningful difference between CPI-trim and CPI-median for our analysis. I mean, let me back this up to what matters, in terms of our analysis.

Q. And I want to give you that opportunity too, but first, I'd just like to confirm that when you've said that there's a single preferred measure, that you now accept that that is incorrect?

A. (Coyne) Well, I accept that they look at three measures. The primary measure is CPI-trim, is my understanding.

Q. Okay.

A. (Coyne) And if I could follow up with the explanation that I have?

Q. No, that might be something that perhaps your counsel will take you to in re-direct, but you've answered my inquiry, certainly, and I appreciate that.

MR. CLARKE: Well, Mr. Chair, it seems to me the witness feels as though this is pertinent to answering the question from Mr. Mahody, so I think he should be given the opportunity to complete his answer.

MR. MAHODY: I won't stand in the way, other than to say I don't think what the witness feels is the measure of whether or not it's responsive to the question, but I'm not going to get hung up on this, Mr. Chair. Thank you.

THE CHAIR: Go ahead, Mr. Coyne.

MR. COYNE: What I was going to add is that for context, we provide an overview of macro-economic conditions in both the U.S. and Canadian markets. It's not a CPI-trim or CPI-median, or CPI, for that matter, isn't a direct input to the models. So this our interpretation of how the Canadian Central Bank goes about doing its business. But it's not a direct input to the models. So be it CPI-trim or CPI-median, it has no consequence in terms of the analysis that we have done or the results of the models that base -- that upon which our recommendations are based.

BY MR. MAHODY:

Q. Part of your qualifications with Mr. Clarke had to do with being an expert in the matters referred to in your testimony, and in your testimony, you say that the Bank of Canada has a single preferred measure of inflation. And you're standing by that testimony?

A. (Coyne) Mr. Mahody, let's go to the testimony that you're citing.

Q. Certainly. We're back at page -- it's N-27, page 511. And it's line 18.

A. (Coyne) And we're back in which discovery request?

Q. This is IR 113, I think.

A. (Williams) Mr. Mahody, I think it might be helpful to have the whole document that you were referring to earlier. Do you have a copy of that speech that we can review?

Q. A paper copy?

A. (Williams) Yes, please.

Q. I do not. I'm sorry.

A. (Williams) I think it would be helpful.

Q. I can get a copy made and provide it to you, sure.

A. (Williams) Thanks.

(SHORT PAUSE)

MR. COYNE: I see that response, and I guess I would just say that that remains my understanding.

BY MR. MAHODY:

Q. And in your testimony, in your report itself, Mr. Coyne, bottom of page number 14, top of the page, 18 of 87.

MR. MAHODY: N-8. I'm sorry, Mr. Goodine.

(SHORT PAUSE)

BY MR. MAHODY:

Q. It's page 45 of the PDF. And Mr.

Coyne, I'm going to line 4.

When you say Figure 4 shows the CPI-trimmed mean, which is the Bank of Canada's preferred measure of inflation, you stand by that testimony as well, despite the words from the Deputy Governor of the Bank of Canada.

A. (Coyne) I do.

And if you look at the chart, you can see that this is reporting the CPI-trim mean from Trading Economics. And Trading Economics is what investors look at.

This is the recurring theme in looking at inflation from the Bank is focusing on the trim mean. I think we can see the plain language in the report that you shared with me that the Bank's analysis of inflation has evolved around the three different mechanisms that it's looked at. Any one of these is painting a picture of inflation that peaked and is now reducing, so the difference between trimmed or median is not important for our analysis.

Q. Okay. I'd like to turn, Mr. Coyne, to the topic of relying on U.S. data when setting ROEs for Canadian electric utilities.

First off, you mentioned your North American proxy group. That's the group in which there's 13 companies, 10 of which are U.S. based? Is that the group?

A. (Coyne) Yes, 13, 10 of which are U.S. based, three of which are Canadian based.

Q. Okay. And Mr. Coyne, you've represented utilities in cost-of-capital proceedings in both the United States and Canada?

[11:40:00] **A.** (Coyne) Yes.

Q. Can you provide an example of where a U.S. regulator has accepted data from Canada -- from Canadian companies when setting the ROEs for electric utilities?

A. (Coyne) I'm not aware of one.

Q. Okay.

A. (Coyne) It's not necessary. The example -- the only counter-example to that that comes to mind is the Federal Energy Regulatory Commission, which set rates of return for gas pipelines, oil pipelines, and electric utilities, and it has recently opened up its analytical approach to include Canadian-based companies in order to achieve a proxy group of sufficient size for establishing rates of return for natural gas pipelines specifically. So that's the one -- that's the one exclusion I can think of to that because, again, it's not necessary because you have a sufficiently robust sample size generated on U.S. utilities.

Q. Okay. So for the setting of return on equity for U.S.-based electric utilities, would you say that you've testified on hundreds of occasions in the United States to set the ROEs in those types of utilities?

A. (Coyne) Oh, I don't know about

hundreds, but many.

Q. Fair enough.

And in none of those occasions have you presented a North American proxy group for electric utilities?

A. (Coyne) No. It's only in Canada that I find the need to do that.

Q. Okay. Mr. Coyne, I'd like to direct your attention to an Ontario Energy Board decision from 2025.

<u>MR. MAHODY:</u> Mr. Goodine, if we could call up the OEB decision that I'd forwarded to you.

<u>BY MR. MAHODY:</u>

Q. And for context, Mr. Coyne, this is the same OEB decision that you had then presented and reviewed as part of the Nova Scotia Power Maritime Link 2026 assessment hearing in December of 2025.

A. (Coyne) I do recall that.

Q. Fair enough.

(SHORT PAUSE)

MS. RUBIN: Mr. Chair, while we're on pause here, I'm just wondering if we can have that Bank of Canada speech marked as an exhibit.

MR. MAHODY: Yes, please.

THE CHAIR: That would be Exhibit N-50.

--- EXHIBIT NO. N-50:

Underlying inflation: Separating the signal from the noise

MR. MAHODY: So Mr. Goodine, I've just sent through to you an email with that attachment.

(SHORT PAUSE)

BY MR. MAHODY:

Q. Mr. Coyne, so we have this report, the decision of the OEB, on the screen now. It's the March 27, 2025 decision. Again, same decision you had been referred to and questioned on in the NSPML 2026 assessment hearing.

You were a participant in that proceeding, Mr. Coyne?

A. (Coyne) I was.

Q. Okay. And I'd like to take you to some of the comments that the OEB decision makes regarding utilizing U.S. data in setting Canadian ROEs. And if we could turn over to PDF page 36 of this decision -- 38 of this decision. And ---

A. (Coyne) Could we expand it a little bit?

Q. Certainly.

A. (Coyne) Thank you.

Q. And it's -- if we could just highlight -- focus on the bottom last 10 lines of the page or so, there the section begins entitled, "There are differences between Canadian and U.S. based utilities that must be recognized."

And the Ontario Board indicates:

> Substantial differences remain between Canadian, and U.S.-based utilities

> principally associated with risk, regulatory oversight and the engagement of U.S. regulated utilities in non-regulated business operations. As well, holding company structures and business holdings, operating in the U.S. and not in Canada, decrease comparability of regulatory results.

Do you see that that was a finding of the OEB in that matter?

A. (Coyne) Yes, I do.

Q. It goes on to indicate:

> The OEB concludes that the 'home bias' of the Canadian investor to invest in Canadian utilities is a factor in giving less weight to U.S. comparators.

You understand that was a further finding of the Ontario Energy Board.

A. (Coyne) Yes.

MR. MAHODY: And over onto the next page. If you could just scroll down a little bit.

Sorry; just a little bit higher, if you could, Mr. Goodine.

BY MR. MAHODY:

Q. At the end of that first paragraph:

> While it may be relevant to consider U.S. utility ROE results, differences in structure and risk limit the ability to find truly comparable companies.

Further finding of the OEB in that matter?

A. (Coyne) And I'm sorry; which paragraph are you referring to?

Q. At the top of the page, the last sentence in that paragraph, "While it may be relevant to consider U.S. utility ROE results."

A. (Coyne) I do see that, yes.

Q. And then further down in the page in the paragraph that begins with:

> The integration of U.S. and Canadian utility markets and the potential lure of higher returns for investors is a factor to be considered in arriving at a final conclusion concerning the requisite ROE that must be provided to meet the [fair return standard]. However, the use of U.S. regulated utility data as equivalent to Canadian regulated utility data in any computation is

questionable.

That was another finding of the OEB in relation to the use of U.S. data; correct?

A. (Coyne) Yes, I see that.

Mr. Mahody, I would like to add my perspective to this, if you'll give me the opportunity.

Q. Certainly.

A. Were there further questions about the decision, though, that you had beforehand?

[11:50:01] **Q.** Well, we'll hear your perspective and then we'll see.

A. Well, as you mentioned, I did participate in the hearing and, you know, the Board had a problem because there were four experts that presented expert testimony before it and Concentric London Economics, who served as the staff expert witness, Dr. Cleary, and Nexus, another consulting firm. And of those four experts, three of the four relied on a mix of either U.S. utilities exclusively or North American utilities, as we did. It was only one expert, Dr. Cleary, that relied exclusively on Canadian companies.

So in reaching these conclusions, the Board faced a dilemma. It was expressing concerns about the equivalency of U.S. data. As you can see in some of these pages, it was backing away from conclusions that it had reached that were quite opposite back in 2009 and yet it was still required to render a decision regarding the appropriate rate of return.

When it did so, following all these comments, it never did evaluate weight that it placed on either Canadian or U.S. samples in reaching its decision, but it did decide on a nine percent rate of return for all of Ontario's utilities on a 40 percent equity ratio, which coincidentally is the exact same rate of return that Nova Scotia Power, that I think all investors would agree, is higher risk that Ontario's T&D utilities only.

So it did not -- Dr. Cleary there recommended a 7.05 percent rate of return. Again, he was the only expert that relied on a Canadian only utility sample. Yet the Board decided on a nine percent rate of return for Ontario's utilities.

So it's quite apparent to me that the Board had to place weight on the results of other experts and weight on U.S. utilities in reaching that conclusion, although it never did specify it in the decision, but I think logic would dictate that it did so.

THE CHAIR: Mr. Coyne, you mentioned what Dr. Cleary had recommended in that proceeding. What rate of return did you recommend in that proceeding?

MR. COYNE: I recommended a 10 percent rate of return based on three models, a North American proxy group, London Economics, relying on just one model. The capital asset pricing model recommended an 8.95 percent rate of return. Dr. Cleary, as I mentioned, recommended a 7.05 percent rate of return. And Nexus Economics recommended an 11.08 percent rate of return.

MR. MAHODY: Mr. Goodine, I've sent

you a document from the Energy Institute at Haas by Werner and Jarvis. Could you call that document up, please?

THE CHAIR: Sorry, just for reference, we'll mark the OEB decision as Exhibit N-51.

--- EXHIBIT NO. N-51:

Ontario Energy Board Decision

EB-2024-0063

MR. MAHODY: And maybe just as we're marking, if we could mark this as the next one so I won't be able to forget it.

THE CHAIR: N-52.

--- EXHIBIT NO. N-52:

Energy Institute WP 329R

MR. CLARKE: Mr. Mahody, excuse me. How many pages is this document?

MR. MAHODY: This document is 79 pages.

MR. CLARKE: Seventy-nine (79) pages. And has -- I'm assuming that this is the first time the witness has seen this.

MR. MAHODY: I was just about to ask him, Mr. Clarke.

MR. CLARKE: Okay. Well, let's find out whether he is.

BY MR. MAHODY:

Q. So Mr. Coyne, are you familiar with this document?

A. (Coyne) I have seen this document previously. I haven't read it recently enough to be able to comment on any one specific page of it because, as discussed, it's 79 pages long, but perhaps we can see how your question proceeds and I'll see if I can be responsive.

MR. CLARKE: Well, my preference would be not necessarily, Mr. Mahody, the witness needs to read all 79 pages, but perhaps you could give some reference to relevant pages and allow the witness to read from that before questions are put to him.

MR. MAHODY: Sure.

BY MR. MAHODY:

Q. I was going to ask questions about pages 2 and pages 3.

A. (Williams) So can we get a paper copy so that we can review it?

THE CHAIR: It might take less time if we just scroll through the pages here and just take a moment.

BY MR. MAHODY:

Q. Yes. And it’s just two sections on -- one section on each page that I wanted to ask you about.

I wanted to refer you to the last full paragraph on page -- it’s PDF page 3, page 2 of the document. Yes. It starts with “In this paper”:

> In this paper we use new data to revisit the central issues of excess returns, capital ownership, and the political economy of utility regulation. We do so by exploring three main research questions. First, to what extent are utilities being allowed to

earn excess returns on equity by their
regulators?

I appreciate other questions are asked, too, but it was that first question that I wanted to ask you about.

And my second point to question you on was over on the next page and the paragraph that begins:

We start our analysis by estimating the size of the gap between the allowed rate of return on equity (RoE) that utilities earn and some measure of the cost of equity they face. A central challenge here, [for both] the regulator and for the econometrician, is estimating the cost of equity. We proceed by simulating the cost of equity using the capital asset pricing model... Using a range of standard financial assumptions we find a premium in approved returns on equity ranging from one to five percentage points over the past three decades.

And my question was going to be for you, Mr. Coyne, if you were familiar with this document or the work of these individuals, who I understand one is from the -- is training at the London School -- or is the Department of Treasury, the other the London School of

Economics -- if you have a general view of what it is that's being expressed here. And you may not, and that's fine.

MR. CLARKE: Well, Mr. Chair, I don't know what Mr. Coyne may or may not say, but I'm more concerned now that the questions come from an introduction to the actual document. And from my point of view, the witness should be allowed some opportunity to go through the rest of it in relation to those questions.

THE CHAIR: Mr. Coyne, are you able to respond to the general questions that Mr. Mahody is getting at, or do you feel you need to get into the detail of the document at this point?

MR. COYNE: With due respect to counsel's concern, I can answer them as long as I stick to the general nature of these comments. I am familiar with the analysis that these individuals conducted.

And if you could go to the first page, please, for just a moment, I want to ensure something.

I won't go over the tips of my skis, though, however, in describing that which is not in front of me.

Could we go to the very first page, the title page?

And I would note here that it says that this is a working paper circulated for discussion and comment purposes. So that's an important context. They have some thoughts.

BY MR. MAHODY:

Q. I know they're not the OEB.

A. (Coyne) No, they're presenting thoughts for comments and analysis for comments. And I have significant concerns about the analysis they conducted, but I can express those if you like.

Q. Again, I'm -- if you are prepared to express those general views, I'm prepared to hear them.

A. (Coyne) Well, if -- let's go back to the third page you were on, I believe. And I'll read this:

> We start our analysis by estimating the size of the gap between the allowed rate of return on equity...that utilities earn and some measure of the cost of equity they face.

What they have done, if memory serves me well, is they have examined decisions that regulators have made over time, and the premise of their paper was to determine if the regulator was setting the right cost of equity.

What they then did is they used one model, the capital asset pricing model, and that's what they say in the next -- the sentence that follows:

> We proceed by simulating the cost of equity using the capital asset pricing model (CAPM). Using a range of standard financial assumptions we find a premium in approved returns on equity ranging from one to five percentage points over the past three decades.

[12:00:01] What they have done over those past three decades is they have held -- used one model and they held -- there are only three inputs to the CAPM model, the risk free rate, which they did vary over time, the market equity risk premium, and beta.

And as I recall, they held the market equity risk premium constant and they held beta constant, and we know that both have fluctuated over time. And then based on their solution to this one model, they observed a difference between allowed returns and what they are producing with their CAPM. And they describe this as what they claim to be a gap or excess returns awarded by the regulator.

They didn't consider the discounted cash flow model, as we have here, they didn't consider the risk premium model, and they didn't even consider alternative inputs to the CAPM model.

So I would describe this as bad analysis that led to results that really can't be substantiated by the work that they did.

Q. Thank you, Mr. Coyne.

A. (Coyne) And I'm not aware of any

regulator that has placed any weight on this paper to date, by the way.

Q. You're aware of evidence in other jurisdictions that have cited and relied on this paper, aren't you?

A. (Coyne) I'm aware of one witness that presented this paper in another proceeding.

Q. Is that Mr. Ellis?

A. (Coyne) I don't recall if it was Mr. Ellis or not.

MR. MAHODY: Okay. Could we turn to -- this is my final question, Mr. Chair -- NSP -- sorry, the response to Board IRs N-27, PDF 1. We're back to the Consensus Agreement.

And if we could just scroll down until we get to the section with the Consensus Agreement that deals with ROE, please.

Thank you. A little bit further down. Yeah. Sorry -- no, it's -- if we go back up, I think, cost of capital is what I should have said. Okay, right there is good.

It's at (a) Cost of Capital and Earnings Band. Right there.

BY MR. MAHODY:

Q. All right. And Mr. Williams, I think this is for you. The agreement uses the phrase, "an overall return on equity". What, if anything, is the reference to "overall" doing there?

A. (Williams) I think it's probably gratuitous drafting, sir, to be honest with you. I don't think it's a necessary word and it could be removed. I don't think it has any particular meaning.

Q. The intention would be to calculate the return on equity in this traditional manner it has been by the Board, and nothing different than that.

A. (Williams) That's correct.

Q. All right. Thank you, Mr. Williams.

MR. MAHODY: Those are my questions, Mr. Chair. Thank you.

QUESTIONS FROM MEMBER MURPHY

Q. I'm just going to ask one question. I have a number of questions for the panel, but I think -- the Chair and I just talked, and we'll probably take a break. But I just wanted to ask one follow-up question from -- based on Mr. Mahody's questions.

Mr. Coyne, I think, if I heard correctly, when Mr. Mahody was quizzing you about inflation rates and whatnot, I thought you had said the inflation rate wasn't really meaningful in terms of your analysis because it's not used in any of your models. Is that correct?

A. (Coyne) The only place inflation enters the models is in the DCF model we use a measure of gross domestic product for the final stage of the model. And there, it is real and it's real growth in GDP plus inflation, so it is an input in that regard.

Q. And am I correct that the inflation rate that you used in that particular model was

2.1 percent?

A. (Coyne) I believe that's correct.

Q. Okay.

MR. MURPHY: That was my only question prior to my other questions, Mr. Chair.

THE CHAIR: All right. So we will actually break for lunch now.

It's five after 12:00. We'll come back at five after 1:00.

--- Upon recessing at 12:05 p.m.

--- Upon resuming at 1:05 p.m.

JIM COYNE, Resumed:

CRAIG FLEMMING, Resumed:

BLAKE WILLIAMS, Resumed:

MICHAEL WILLETT, Resumed:

THE CHAIR: Okay. Welcome back, everyone. Over to Board Member Murphy.

MR. MAHODY: Mr. Chair, ---

THE CHAIR: Sorry, Mr. Mahody.

MR. MAHODY: Just for clarification, I've provided Mr. Clarke with paper copies of the Deputy Bank of Governor -- Deputy Governor of the Bank of Canada's comments, and I did refer to it occurring at Queen's ---

(SHORT PAUSE)

THE CHAIR: Mr. Mahody, you were saying?

MR. MAHODY: And so the speech was in London at Western, not in Queen's.

Thank you.

THE CHAIR: Someone from Western got to you?

MR. MAHODY: Well no, but Dr. Cleary is from Queen's and he'll be after me, so...

(LAUGHTER)

THE CHAIR: Thank you, Mr. Mahody.

Mr. Murphy.

MEMBER MURPHY: Thank you, Mr. Chair.

QUESTIONS FROM MEMBER MURPHY, (Cont'd)

Q. Good afternoon, panel. I think the bulk of my questions are probably for you, Mr. Coyne, but, you know, the rest of the panel can jump in if they want. But primarily I think for you, Mr. Coyne.

My first set of questions relate to some of the business risks that you noted that apply -- that you believe apply to Nova Scotia Power.

So the first question I have I related to the risk related to the ownership of generation assets. And I don't think we need to call it up, but you referenced it in your evidence. And you said unlike most other regulated electric utilities in Canada, Nova Scotia Powers owns substantial regulated generation assets. In 2024, Nova Scotia Power derived 63.9 percent of its power supply from company-owned generation facilities and 36 percent from other suppliers. Do you recall that?

A. (Coyne) I do, yes.

Q. I guess this might not be a

question for you. It’s probably a question for one of the other panel members. But do you know what percent of energy supply Nova Scotia Power projects in ’25, ’26, and ’27 that it will generate from its own facilities?

A. (Williams) Mr. Murphy, I think we could dig that up for you, but rather than do that, I think that if it would be okay with you, I suspect that’s a question that could be answered relatively quickly by the next panel.

Q. Are you on the next panel?

A. (Williams) I am, but ---

Q. I may need somebody to remind me. That’s all.

A. (Williams) Yeah, you won’t need to remind me, sir.

Q. Okay.

A. (Williams) I’ve got it. Thanks.

Q. Okay. Back to you, Mr. Coyne.

In the prior GRA, in 2022, I can call

it up if it you want, it was your evidence, but you may recall it, you showed a figure, Figure 34, that showed Nova Scotia Power-owned generation in 2021 produced an approximately 82 percent of its power supply. Do you recall that?

A. (Coyne) I don't recall the number, but I recall -- the trend makes sense to me.

Q. Okay. So between '21 and 2024, Nova Scotia Power has reduced its -- according to these numbers, Nova Scotia has reduced, and so on, its own source of generation by roughly 18 percent. My question really is, did you factor that -- how did you factor that into your risk analysis for Nova Scotia Power? Would it have lowered Nova Scotia Power's risk relative to 2022, or the 2022 GRA, as it relates to Nova Scotia Power's ownership of its own generation assets?

A. (Coyne) I didn't make a specific adjustment then or now on that basis because the proxy group that I selected then and now is still vertically integrated. And each of these vertically integrated utilities rely, to varying degrees, on a mixture of their own generation and purchase power resources. So I didn't really have a basis for making an adjustment specifically, or I didn't make an adjustment, either then or now. But I think the point you make is a fair one, that full utilization of the Maritime Link is helpful to the company and its customers, and to the extent that it's substituting its own generation resources with Maritime Link resources, I think that does lower its risk incrementally.

[1:10:13] **Q.** Compared to your 2022 assessment?

A. (Coyne) Yes.

Q. Okay. Thank you. Maybe I will ask ---

A. (Coyne) I should add, Mr. Murphy, though, but the company, of course, still has to fully make the transition, of course, with the existing resources that still remain on its books, and it's making progress in that regard to do so. But that's also part of the equation.

Q. Sure. Okay. Thank you.

MEMBER MURPHY: Maybe I will ask Jeff to call this one up. It's Exhibit N-27, Jeff, Response to Board Staff IR-23, PDF page 530.

BY MEMBER MURPHY:

Q. Mr. Coyne, this relates to the risk that's been identified associated with the DDA and securitization and whatnot. So ---

A. (Coyne) In which ---

MEMBER MURPHY: Just scroll up there, Jeff. It's ---

MR. COYNE: Is that an IR response?

MEMBER MURPHY: It's IR Response 123.

Page 530, Jeff. Sorry, no, that's the right IR. Scroll down a bit. Keep going. Yeah, right there.

BY MEMBER MURPHY:

Q. So here you're talking about how you, I guess, reviewed and assessed the risk related to securitization and how it might impact Nova Scotia Power's business risk. The first sentence I'll draw your attention to, it says, "Given that..." -- this is the securitization plan.

> Given that the [securitization] plan has yet to be submitted or approved, there is no change in business risk at this time.

So am I correct, based on that sentence, that, relative to your 2022 GRA business risk assessment, you didn't make any adjustment related to Nova Scotia Power's business risk related to securitization?

A. (Coyne) No specific adjustment to the numbers, because the -- again, I relied on a proxy group of integrated utilities and I didn't make an incremental downward -- downward or upward adjustment back in 2022, or any incremental adjustment in this proceeding. I just noted, as a change in risk, the credit rating agencies, as I point out and has been pointed out elsewhere, have noted this is a positive development, if it should occur, for the company.

Q. Right. And I think on your last sentence of this bullet, it says:

> On balance, Concentric views the securitization plan as a mechanism that will improve [Nova Scotia] Power's credit metrics, provide a benefit to customers through lower rates, and finally facilitate progress towards the Province's energy transition.

You see that?

A. (Coyne) Yes.

Q. So I guess given that assessment, and under the assumption that securitization does proceed, should there not be a risk adjustment downwards, as it relates to Nova Scotia Power's business risk?

A. (Coyne) Well, if you were -- again, when you say a downward adjustment, the way we conduct this analysis is we compare Nova Scotia Power to a group of vertically integrated utilities. Many of those utilities do not face the challenges that Nova Scotia

Power faces, in terms of transitioning its fossil fuel heavy generation fleet to one that’s less fossil fuel heavy.

So one might argue that it could have made an upward adjustment in prior proceedings for not having made that transition. I think the transition probably brings Nova Scotia Power closer to how other utilities have generation fleets, but -- and the composition of those fleets. But no, we didn’t make any downward adjustment as a result of that transition. All companies are making that transition, to one degree or another. I think Nova Scotia Power had a steeper hill to climb than many of its peer companies. Securitization, should it occur, it certainly assists that process and provides a substantial benefit to customers through lower rates, as we mentioned, should it occur in this fashion.

Q. Okay. Thank you.

A quick one on the risks related to the proposed storm rider. Am I correct that you made no adjustment compared to the 2022 GRA business risk assessment as it relates to the storm rider? Am I correct?

A. (Coyne) That's correct.

A. (Flemming) Mr. Murphy, I have been able to locate those figures for you, in terms of the generation versus purchased power, if you'd like to take those now.

Q. Okay. I've just got to go back and remind myself about the question.

A. (Flemming) I believe the question was what is the percentage of Nova Scotia Power generated energy.

Q. Oh, right. Yes.

A. (Flemming) In 2025, 62 percent; 2026, 61 percent; 2027, 51 percent is what we're forecasting.

Q. So the big jump would be in 2027?

A. (Flemming) That's right. As we

noted, the -- some wind projects that we expect to come on reducing Nova Scotia Power's generation.

Q. Okay. Okay, thank you for that.

Just a couple of questions, Mr. Coyne, on your regulatory risk assessment.

MEMBER MURPHY: Jeff, if you could call up Exhibit N-8, PDF page 100.

BY THE CHAIR:

Q. Mr. Coyne, I think that's -- in your hardcopy at the bottom I think that's page 68.

A. (Coyne) I'm with you, Mr. Murphy.

Q. Okay. It's the first paragraph, and it talks about recent decisions by the Board where capital costs and operating costs have been disallowed and whatnot. And you specifically reference the example in a 2018 AMI decision where the Board approved recovery of the underlying costs of retired meters over a five-year period, including debt costs, but not including an equity return. And then you go on to say this decision is particularly relevant as NSPI will need to retire approximately $1 billion in thermal generation assets as part of the clean energy transition and recover the associated costs.

As it relates to the amount that's intended to be securitized, which is roughly 700 million, is that point a bit moot now? When you're comparing it to a decision where the Board, you know, only allowed debt costs on the AMI meters, as part of securitization those assets will only receive a debt return as well; correct?

A. (Coyne) Some additional context on the securitization from my fellow panel members. Would you mind repeating your question for me, Mr. Murphy?

Q. Sure. You specifically reference the example from the 2018 Board decision related to the AMI meters where the Board approved recovery of the underlying costs of those meters, including debt costs, but didn't allow an equity return on those. And then you say this decision or that decision is particularly relevant as NSPI will need to retire approximately $1 billion in thermal generation assets as part of the clean energy transition and recover the associated restoration costs. My question was really as it relates to that example you gave to the AMI decision is that kind of a moot point now given the securitization of roughly 700 million?

[1:20:40] **A.** (Coyne) I wouldn't say moot point. I would say it's a different point. Because of the treatment of the thermal assets through securitization, certainly a positive for customers, and by assisting with this transition through providing, the process of securitization will be backed by -- it's a government-backed -- government-backed debt, and the company will incur -- that the company will be responsible for. But I don't see that -- again, I see it as a constructed development for customers. I don't see it as a negative for the company per se. I think it's a positive development.

Q. The concern I guess -- the way I read it was the concern you're expressing was perhaps, you know, the more -- the company may not get its equity return on the 700 million that would be securitized because you were comparing it to the AMI example where there was only debt. But in this case now there's only going to be debt on that anyways. There's no equity return on it.

A. (Coyne) Well, that's true. I mean, most utilities when they establish rate base do financial planning around experiencing both an equity return on those assets through the end of their useful lives. So in this case that will be a foregone equity return on that $700 million. From an investor's standpoint that's generally not viewed as a positive. But I think an investor, as you have seen in the credit rating agency's note, would view it as a positive because it's a resolution towards developing an accelerated approach towards transitioning the fleet for the company. It's in the public good.

And so all in all I think it's viewed positively, certainly from a debt investor's standpoint, and I think also from an equity investor's standpoint just because the progress towards transition it makes.

A. (Williams) Mr. Murphy, if I could just add -- if I could just add one point, sir? And I think I understand where you're going with that. But I think it's important to remember the securitized amount is as of a certain date the net book value that it would be continuing to be ongoing capital investment in certain of those assets where the same risk or the same concern would exist. But I take your point on the 704 million, that that would be addressed through securitization.

Q. Okay. Thank you.

A question -- I'm moving on to your proxy -- your selection of proxy companies. Mr. Coyne, just a couple questions.

In the 2022 GRA Application, Algonquin

Power is included as a Canadian proxy company, and it doesn't appear that they're included this time, and I'm just -- I'm curious as to why.

A. (Coyne) My recollection -- and I don't see this in the write-up that's here -- is that Algonquin experienced a period of a negative dividend growth, which wouldn't have qualified them for inclusion in my Canadian proxy group. You can't really conduct the analysis unless you have a positive dividend growth for the company.

That's my recollection. So I included the five that did meet the criteria I have for inclusion in the Canadian proxy group that didn't include Algonquin.

Q. Okay. Thank you.

And one last question on those proxy companies. In this current year, one of the screening criteria for the USA proxy group was that it consistently pay a quarterly cash dividend and not have reduced or eliminated those dividends in the past two years. And in the prior GRA, that second part, have not reduced or eliminated those dividends in the past two years, was not included. Again, just curious why. Why the change?

A. (Coyne) The -- you know, going through the period of COVID, we saw some unusual circumstances with utilities, where some utilities withheld dividends that they had not previously done so. So we just made it a little bit more -- a little bit more reflecting the reality of some utilities pausing their dividend growth or eliminating it during that period. That was not typical of utilities in the past.

Q. Okay. Thank you.

I'm going to move on to your models, I guess, the CAPM, discounted cash flow and equity premium.

My first questions are related to the CAPM model. And I can ask Jeff to bring these up, but I'm hoping perhaps your memory -- given you were here not too long ago for the NSPML hearing, I'm hoping your memory is good. Otherwise, I'll get Jeff to bring the numbers up.

But based on my review of the cost-of-capital report that was filed in the NSPML proceeding, the -- you correct me if I'm wrong, the inputs for the NSPML proceeding -- the inputs for your models were as of -- the CAPM models were as of May 31st, I think, of 2025. And this current GRA, the cost-of-capital report is based on inputs from January of 2025. Is that correct?

A. (Coyne) That's correct, yeah.

Q. Okay. So when I looked at the -- let's just start with the betas, I guess.

When I look -- there's two proxy companies that are common between the -- Canadian proxy companies that are common between the NSPML Application and the current Application, and those are Canadian Utility, CU, and Hydro One, H. And when I look at the betas in the NSPML Application, the beta for CU is 0.63 and the beta for Hydro One is 0.58, whereas in the current Application, the beta for CU is 0.86 and for H it's 0.69.

And as well, the market risk premium

numbers and the risk-free numbers have changed between those two applications.

And it appears to me to make a difference. In the NSPML Application, using the CAPM model, the ROE for Canadian utilities was 8.19 and in this Application it's 9.71. And for H in the NSPML Application it was 7.86 versus 8.63 in this current Application. And the NSPML Application, again, is based on a little more recent data.

So I guess, given that the current -- or the cost-of-capital report that's been filed in this proceeding, the numbers are roughly a year old -- or in terms of the inputs, anyways, are roughly a year old and it appears that the betas, for example, for CU and H, have declined between January and May. Do you know if -- for those two companies, do you know if the betas have changed from May? Have they gone down further, or...?

A. (Coyne) For those two companies or in general?

Q. For those -- well, I'm going to ask those two first and then I was going to ask about the other proxy companies.

I know it's not the same proxy companies between the two, but the other companies that are listed in the cost-of-capital report that's contained in this proceeding, would the betas have changed since January 2025?

[1:30:03] **A.** (Coyne) Well, the betas are always changing, and they should because the idea of beta is, ultimately, you're trying to reflect what investor expectations are of the companies. So in an ideal world, they're always forward looking.

We don't have a forward-looking forecast of betas, so the best we can do is to take a running five-year average of those betas on a weekly basis and use that as a basis for forming investor expectations.

Those are the same betas that are published by Valueline, so I feel pretty good about using that data in that way.

But they're always changing. So every month we would have a new beta for Bloomberg because we're updating Bloomberg betas as we go. Valueline updates its betas quarterly for each company that it follows.

So in any given application, we will see betas change from one report to the next.

And as you rightly pointed out, the proxy groups for NSPML are different than those we used for NSPI because there we were looking for T&D only proxy companies, whereas here we're looking for vertically integrated utilities, so we selected different proxy groups for that reason.

Q. But there is two common proxy groups between the two proceedings.

A. (Coyne) Yeah. Yes, two companies, as you mentioned.

Q. Two companies. That's right, yeah.

A. (Coyne) Yes.

Q. And the betas have changed significantly.

Well, let me ask you this. You know, I don't recall exactly the date that this GRA was filed, but was there any reason that the cost-of-capital report wasn't updated to provide more recent inputs rather than January of 2025?

A. (Coyne) My recollection was that's when we conducted our analysis and, at that point in time it -- shortly thereafter, were finalized for the company's filing.

Q. But it's -- is it fair to say as well, though, that between January of 2025 and May of '25, at least for those two proxy companies I mentioned, you calculated ROEs of -- you know, declined by -- using the CAPM model, have declined by over 1 percent in one case -- or sorry, close to 1 percent in each one. So it could change again, I suppose, between May and, you know, the following quarter or more recent data, I guess.

A. (Coyne) Sure.

Q. You know, if we were to rely on the most recent data that we have, which is from the NSPML proceeding, the ROEs for at least those two companies are significantly lower.

A. (Coyne) Right. The data's always changing and we would expect them to change from -- they could change from month to month, and we'll reflect those updated data in our models as we do.

Now, I think that's an important distinction between how we conduct our analysis and, say, Dr. Cleary, who decides that the beta's 0.45, and it's always 0.45, you know, without adjusting for changes in market data.

Q. I understand that. To me, that's a separate issue. What I'm talking about is the recency of the data, I suppose. Is it normal in a GRA Application where you're asking for a certain cost of equity or the company's asking for a certain cost of equity -- is it normal to rely on data that's a year old?

A. (Coyne) Oftentimes because by the time we conduct our analysis, it gets finalized in the application and, depending upon the lag between then and when we go to hearing, we do have periods where it is about that old.

Q. It wasn't the case in NSPML, though, was it?

A. (Coyne) No. There was a difference in the filing timing there. Yeah.

But I would say that I'm also mindful of the fact that, you know, we do this analysis every month and in different proceedings, and I don't think we would -- what we've seen over the course of the year is that Valueline betas have come down over the course of the year more so than Bloomberg betas have.

I'm sorry. They have lagged Bloomberg betas coming down because of when they update their analysis. When we factor that all in to the CAPM model, we find that betas have come down some, interest rates have gone up some so you have some offsetting effect if you're, you know, thinking about what you may be anticipating, and that is how it has changed the analysis. We would see some offsetting effect there between lower betas and higher interest rates.

The market equity risk premiums have come up a little bit when we factored in the next year's data. So you get a little bit of a wash between those three things. As the CAPM numbers have come off a little bit, the DCF numbers have come up a little bit. The risk premium numbers have come up a little bit as a result of slightly higher interest rates. If you factor it all through the three models, I don't think you'd get a very different result than that which we presented here.

And perhaps most importantly, I think it's worth considering that the company has proposed a 9 percent ROE through the settlement, and there is no --

there is nothing that's happened in the data that would suggest that the analysis that we have conducted would ever get down to that level or below it.

Q. Now, I understand that, but again, there's been a -- at least for these two companies that I mentioned using that CAPM model, there's a significant difference to what was presented in the NSPML Application and this particular Application. And I guess it's, at least to me, it's perhaps concerning that there's that significant of a difference and we're relying on data that's a year old.

So what I was going to ask, and this may be a big ask, but what -- let me ask you this: If you were to update these numbers, what's the most recent date that you would be able to get sort of the Valueline or the Bloomberg beta numbers? If it's quarterly, then presumably that would be June/July.

A. (Coyne) Well, for beta, we update instantaneously using the Bloomberg terminal. So we're always getting -- we're never more than a week out of date because those are weekly betas on a trailing basis.

For Valueline, it just depends on when they -- they update not at the same time for all companies, so you could have some reports that are a couple of quarters old, and others that are more recent than that. So you're always going to have a little bit of a lag depending upon when Valueline updates reach company.

I'm not sure, does that answer your question, specifically in regards to beta?

Q. Well, I guess what -- I guess where I'm going is I think I'd like to get an undertaking to get the CAPM model at least updated for the most recent data. Because I do think it, at least for me anyways, it is concerning that within a three-month span, for at least two of those proxy companies that are included now, that the calculated ROE has declined pretty significantly.

A. (Coyne) Could you give me one moment to consult with my fellow panel members?

Q. Sure.

A. (Coyne) Okay.

(SHORT PAUSE)

MR. COYNE: So Mr. Murphy, we -- as I was sharing with my fellow panel members, we update our models monthly, the data that goes into those models, and so that we can use them in the various proceedings that we're involved in, and we don't -- we haven't yet downloaded the December data because we don't have it for all the data inputs that we require. But we could rely on models that were -- where we had data uploaded through November.

But I would note that if we were to update the analysis, I would want to do it for all three models because that's the basis of our recommendation, not just the CAPM. So I would suggest to you, if it's acceptable, that if you would like, through an undertaking, for us to update our analysis that we do it for all three models.

BY MEMBER MURPHY:

Q. Well, I was going to note that for those two companies, CU and H, that the other two models also produced different numbers in the NSML -- NSPML proceeding. They weren't as significant as the CAPM difference, but they were a little bit lower.

[1:40:01] So I might have asked for it anyways, so if you're offering to provide it for all three models, that's fine with me.

A. (Coyne) I feel it would give you the fuller picture if we could do so.

Q. Sure, that's fine with me.

MEMBER DEVEAU: Just before we finalize that, so you'd be updating all the inputs, is that what you're saying?

MR. COYNE: Yes, it would be everything across the board. So it would be everything from interest rates to ---

MEMBER DEVEAU: Yeah.

MR. COYNE: --- dividend yields for the companies in the DCF model and ---

MEMBER DEVEAU: So you say that the -- that change in the -- that change in the beta might be offset or would be -- you said, you asserted that it would be offset by higher interest rates. Do you mean rates set by the FOMC or the Bank of Canada, or are you referring to bond yields, or what exactly are you referring to when you say interest rates are increased?

MR. COYNE: Their long-term forecasts for bond -- 30-year bond yields that go into the models.

MEMBER DEVEAU: For the banks, central banks?

MR. COYNE: No, not for central banks. They're a 30-year, publicly traded 30-year bond yield.

MEMBER DEVEAU: Oh, I see; sorry. Okay.

MR. COYNE: Right. And this is the consensus economic forecast that we use that goes into the models. And so we would update it comprehensively. I think that's the only appropriate way to do it for you ---

MEMBER DEVEAU: Right.

MR. COYNE: --- rather than to do it on a piecemeal basis.

MEMBER DEVEAU: Right. Okay, thank you.

MR. COYNE: You're welcome.

And you know, that would take us a few days because it takes us -- we have to run the models, check the inputs, and then we go through an auditing process to make sure that we have done our work correctly.

THE CHAIR: Okay, so that's the -- that's to -- Undertaking U-14, to update the Concentric cost of capital models.

UNDERTAKING U-14 - To update the Concentric cost of capital models

MR. MAHODY: Mr. Chair, as I hear the evidence, I understood it was going to be a comprehensive update, so it was going to involve -- include, for instance, CEA2, the macro economic assumptions. All of this is getting updated is the intention of the undertaking?

MR. COYNE: Yes, it would, Mr. Mahody. What we -- what I would propose to do for efficiency would be to provide an updated set of exhibits, and the exhibits contain all the analysis and the inputs to the models. And I think that would provide the appropriate side-by-side comparison to the same set of exhibits and inputs provided in the testimony.

What I wouldn't -- what I wasn't proposing to do would be to update the entirety of the testimony because that takes longer because of the narrative element of the process.

MR. MAHODY: I'm not asking for that, so ---

MR. COYNE: Oh, good.

MEMBER MURPHY: Nor am I.

MR. MAHODY: --- that's fine. Thank

you.

MR. COYNE: I'll express my relief.

BY MEMBER MURPHY:

Q. But you'll provide that undertaking in an Excel format too; correct?

A. (Coyne) Yes.

Q. Yeah.

A. (Coyne) Yeah.

Q. Okay, thank you.

A. (Coyne) You're welcome.

Q. Just a couple more questions, then, and this really relates to some ROE numbers presented in your evidence.

MR. MURPHY: Jeff, if you could call up Exhibit N-8, PDF page 84.

BY MEMBER MURPHY:

Q. And for your, Mr. Coyne, I think that would be, yeah, 52 at the bottom. And it's Figure 30 I'm going -- that my questions are about. Do you see

Figure 30?

A. (Coyne) Yes, I do.

Q. Okay. So Figure 30 shows authorized electric utility ROEs and equity ratios. And my first question is about the Ontario electric utilities ROE, and it says 9 percent. I think that's been updated recently to 9.11, I believe, OEB is updated to 9.11.

A. (Coyne) That's correct.

Q. But it also says that it doesn't apply to generation. And I may be wrong, but it's my understanding that when the OEB sets the rates for its electric utility, it also includes OPG, or Ontario Power Generation. Is that correct?

A. (Coyne) That's correct. The OPG has a -- they -- their ROE is also set by the formula, but they have a different equity ratio. They have a 45 percent equity ratio.

Q. Sure, but ---

A. (Coyne) So that would be an

appropriate footnote.

Q. Yeah, I understand that, but as it relates to this table, the OEB does set the ROE for OPG; correct?

A. (Coyne) For the one regulated generator, which is OPG.

Q. OPG.

A. (Coyne) Yeah, which is government owned, yes.

Q. And then ---

A. (Coyne) The other generators participate in the open market and they don't have a regulated ROE, per se.

Q. Right. But for OPG, the authorized ROE is the same as the other T&D distributors?

A. (Coyne) That's right. They distinguish risk with the equity ratio, which is 45 percent. And they are currently before their Board requesting a higher equity ratio beyond that, given their new developments of their nuclear fleet.

Q. Okay. But as of right now, in terms of ROE, they don't differentiate between the T&Ds and the OPG, who is a generator?

A. (Coyne) That's right.

Q. They both have ---

A. (Coyne) Yeah, the purpose of this table is to compare NSPI to other utilities' distribution and/or T&D, or T&D vertically integrated utilities. OPG is a special animal.

Q. Yeah, I suppose what it might suggest, though, would it not, is if the ROE for OPG is set at the same ROE as the T&D companies that the regulator there doesn't really see much of a risk difference between the two?

A. (Coyne) Well, that's not true. They see a significant difference in risk. It's a very high bar in Ontario to have anything other than a 40 percent equity ratio. And the only company that they distinguish that difference for is OPG as a result of it being a generator. So 45 percent is a significant difference, compared to the T&D utilities, and they are currently before the Board requesting an even higher equity ratio on that basis.

Q. Okay. Just one last question on capital structure.

MEMBER MURPHY: Jeff, can you go to PDF page 87, please, Figure 31?

BY MEMBER MURPHY:

Q. Mr. Coyne, that's page 55 for you at the bottom. Do you see that? Okay.

So just below that table, you have some verbiage there. It says:

> We also compared [Nova Scotia Power's] deemed common equity ratio of 40.0 percent to the authorized equity ratios for the operating companies held by Electric T&D proxy group that is in our [NSP Maritime Link] report....As shown in Figure 7 of that report, the average authorized equity ratio[s] for those companies is...49.0 percent, reflecting higher overall common

equity...than [NSP], which owns substantial...generation...

I was going to get Jeff to call up that exhibit from the NSPML hearings. Jeff, it's the one I sent you, M12394, Exhibit N-1, and it's PDF page 91.

<u>BY MEMBER MURPHY:</u>

Q. I think this is the figure you're referring to, Mr. Coyne. In the text, it says Figure 7, but I think it's actually this figure that you're referring to. I can take you to Figure 7 if you want, but it's not related at all to the authorized ROEs.

A. (Coyne) I think you're correct, Mr. Murphy. This looks like what I was referring to.

Q. Okay. So in this figure, I think your statement's correct that the average equity ratio for those proxy companies is 49 percent, but I just want you to confirm that for the two Canadian electric utilities, that the equity ratios are 37 percent and 40 percent?

A. (Coyne) That's right. As we note in our report here, equity ratios for Canadian companies are typically lower, on average, than they are in the U.S. But these two companies are also pure play T&D companies and not vertically integrated. But even on that basis, they are lower.

[1:50:07] **Q.** Okay.

MEMBER MURPHY: Those are all my questions, Mr. Chair.

THE CHAIR: Mr. Deveau?

QUESTIONS FROM MEMBER DEVEAU

Q. Good afternoon, panel. Mr. Coyne, you'll be happy to know I have no more questions on the Fuel Adjustment Mechanism.

Yeah, Mr. Murphy had asked you just now why, given the positive nature of the securitization, why there wouldn't be an upward adjustment, positive adjustment, in terms of the risk, and you responded to him that, if I understood you correct, was that the proxy group that you're using, that Nova Scotia Power is an integrated company -- utility, so they have to securitize thermal assets that other members of the proxy group would not have to do -- would not be in the same position. Is that what your response was?

A. (Coyne) I'm not sure of the exact words that I used, but to paraphrase what I think I said, the other members of the proxy group, they're vertically integrated, so they all own generation assets. And some have greater -- to the extent that all are moving in one

-- all are moving, to one degree or another, transitioning their generation fleets generally towards a goal of decarbonization, albeit that may have slowed somewhat in the U.S., based on current policies, but it's still an overall trend, based not only on public policy, but also just based on pure economics, as the cost of renewables come down and the cost of other resources come down as well.

But what's unique about Nova Scotia Power is the degree of the thermal assets that they've owned, and the amount of transition required is greater, in my experience, than it is for many of these companies, although companies that are in the proxy group also had substantial generation fleets that have -- that are looking at advanced retirements and accelerated transition based on their own company goals or based on public policy goals set by their governments.

Q. So those other members of the proxy group have not had to do securitization? Is that what you're suggesting?

A. (Coyne) Most have not, no. I'd say securitization is the exception. There are four or five companies I know of in the U.S. that have worked with their legislatures or governments to adopt securitization, where, like here, it was the magnitude of the transition and economic costs were deemed to be so significant that a securitization tool was deemed, by and large, to be in the best interest of customers. So they have -- that tool has been used elsewhere, but it's more unusual than not.

Q. Right. So -- and I don't have the actual states on the tip of my tongue, but -- and generally they're coal; I think there has been nuclear, but the ones that have had coal, why are those not making into the comparator group -- proxy group? Are there other factors that disqualify those? That they're either not -- they're not integrated, or is there something else that distinguishes those particular companies?

A. (Coyne) Well, I believe that some have are. So for example, Duke has either proposed or enacted securitization in one or two of its jurisdictions.

Q. Right.

A. (Coyne) And that's part of my proxy group. I would have to research the others to see if they've operated in jurisdictions where securitization has been adopted. But I would say it's more than the exception than a rule. Members of the panel may know from their own studies, but I don't have that data at my fingertips.

Q. Right. No, that's fine. That's fine.

You responded to a question from Mr. Mahody about -- he asked you about whether American regulators used Canadian utilities in their comparator groups, and you mentioned that FERC actually did include Canadian companies. And I know that Enbridge, which is a Canadian company, has a pretty significant presence in the United States, and just looking at their website quickly, and I know that they transport -- their POC (Sp?) lines transport about 20 percent of natural gas that's used in the United States, so obviously a very significant player. Do you know if Enbridge is included in that group and if there are others? Well, I'll put up that my premise is that they probably included Canadian comparators, it probably is Enbridge, because Enbridge is such a big player in the United States.

A. (Coyne) Right. I think the two that would be considered would be Enbridge and TransCanada.

Q. Yeah, TransCanada is the other one. Okay. And TransCanada similarly has a significant presence in the United States; is that correct?

A. (Coyne) Yes, they do.

Q. Okay. So to the extent that they have a presence -- those utilities have a presence in Canada -- sorry; in the United States, aren't they -- isn't there a distinction that the American comparators that you're using do not have a similar presence in Canada?

A. (Coyne) Of those in my proxy group the only one that I believe has a significant presence in Canada would probably be Nextera, primarily through their transmission investments. But I think that's not an unreasonable observation. We've seen much more cross-integration -- much more investment integration from Canadian holding companies into the U.S. then we have seen reciprocally. And one of the observations that I've made is that working with these companies, and also working with Canadian pension funds and investors, they are seeking higher returns, and they're finding higher returns, on a risk-adjusted basis, in the U.S. versus returns that they experience in Canada. And that's why we're seeing such a significant influx of investment from Canadian holding companies into U.S. enterprises.

Q. Okay. Thank you.

Now, we'll turn to your report. So

appendix -- Exhibit N-8, Appendix 10(a), and we'll go to PDF page 92, which is page 60 of your report at the bottom.

You're there on page 60?

A. (Coyne) Yes, I'm with you, Mr. Deveau.

Q. So here is basically where you're getting into your conclusions and your observations about business risk, and you mention the carbon transition risk. And I take it -- am I right in saying that when you're talking about the carbon transition risk you're talking about the transition from coal generation to renewables and also your (indiscernible) assets; is that correct?

A. (Coyne) Yes.

Q. Okay. If you turn the page to page 61 ---

A. (Williams) Sorry, Mr. Deveau, if you give us one second.

Q. Yes.

A. (Coyne) I'm with you, Mr. Deveau.

Q. Okay. So turning to page 61 you -- starting around line 5 there -- we'll, first of all, you mention, obviously, the renewable goal and the retirement of coal-fired generation in the first few sentences there. And then at the end of line 5:

> In October 2023, the Province published its 2030 Clean Power Plan. The plan calls for the addition of new wind, solar, and natural gas capacity to the grid, as well as investments in battery storage, and new transmission line to New Brunswick [improving] the reliability of the grid.

And then:

> The Province also announced that it was abandoning the proposed Atlantic Loop...to decarbonize the electrical grid by 2030,...

[2:00:32] And then you refer to the Morningstar DBRS report, and that would be the report from January of 2024, and you say:

> Morningstar DBRS is encouraged that there is now a plan for NSPI to achieve its provincially mandated renewable generation targets, and there is alignment with the Province that substantial capital

> expenditures...will be required. However, Morningstar DBRS expects [that] these plans will require substantial funding support from both the Provincial and Federal governments under an ambitious time frame. Morningstar DBRS will continue to monitor the Company's progress, especially with the release of the Clean Electricity Solutions Task Force report expected early in 2024.

So you do mention -- if we turn to page 62, the next page, in the second half of the page you do refer to positive developments in terms of the DDA, Decarbonization Deferral Account, as well as the proposed securitization, which you mention there.

And then I'll take you to your page 79, PDF 111. So this -- these are your conclusions -- risk analysis conclusions, and I'll take you to the second bullet:

> The business risk of NSPI remains elevated as it was at the time of the last GRA in 2022. In particular, the Company must comply with environmental requirements related to an accelerated decarbonization of its generation fleet by 2030.

A. (Coyne) I apologize, Mr. Deveau.

Q. Sorry?

A. (Coyne) I want to get on the same page with you.

Q. Yeah, yeah. Sorry.

A. (Coyne) Which page number is it?

Q. Your page should be page number 79.

A. (Coyne) At the bottom?

Q. Yes. Should be bullets at the top.

A. (Coyne) Now I'm with you.

Q. Okay. So these are -- your conclusions are risk analysis, and you open the paragraph by saying, "The business risk of NSPI remains elevated as it was at the time of the last GRA in 2022."

And then your last sentence there in the third line, line 10:

> This transition from thermal generation to renewable resources is already underway but will continue to require substantial amounts of capital over the next five years and expose NSPI to risks such as renewable

electricity standard and emission compliance.

So you had mentioned, in a previous excerpt I referred to you, battery and transmission. Since those were introduced into the discussion you may be aware that the Nova Scotia and New Brunswick Transmission Intertie Project was brought forward to the Board. First in March of 2025 the Canada Infrastructure Bank provided financial assistance to the transaction to the tune of $217 million. So that was a significant project, almost $700 million -- or the balance of it was $685 million. So that was put forward again with significant financial support from the federal -- the Canada Infrastructure Bank, which is a federal agency, and that was approved by the Board, I think, in November. I didn’t see your reference to positive federal government assistance to that particular project or the fact -- in fairness, it was approved after your report, but the financing -- the announcement of the financing by the federal government was announced before your report.

So I didn't see that mentioned in your report. Wouldn't that be a positive development?

(SHORT PAUSE)

MR. COYNE: I apologize for the delay, Mr. Deveau.

No, that's a more recent development that I captured in my report and even our discussion here indicated that the results and impact of that project and how they'll impact the company will be something perhaps we'll learn on a going-forward basis, but from what I understand, it should accelerate the development of renewables for the Province, which would be of benefit to the company's customers.

BY MEMBER DEVEAU:

Q. Okay. Certainly the Nova Scotia Power panel that appeared in that hearing seemed to be very positive about it, so...

A. (Williams) Mr. Deveau, it is ---

Q. You were counsel, though. You

weren't on the panel.

A. (Williams) I don't believe I was counsel in that proceeding.

Q. That's true, actually.

A. (Williams) And I just want to be clear on the record, we would see that as a positive.

Q. Right.

A. (Williams) But I think, as you're aware, it's a separate entity, it's a separate rate base.

Q. Right.

A. (Williams) I don't think it necessarily would impact Nova Scotia Power's risk as we've been discussing it, but it certainly would impact Nova Scotia Power's risk as we've been discussing it. But it's certainly a positive development and part of the ongoing positive work that we've been able to accomplish with our both federal and provincial government partners.

Q. Right. But Nova Scotia Power is a part of the project.

A. (Williams) Nova Scotia Power has a role in the project, certainly.

Q. Right. And they're the lead -- they're the lead on that project; correct?

A. (Williams) We have development agreement that -- it's a separate entity that's constructing ---

Q. Right.

A. (Williams) --- (inaudible due to mumbling) it.

Q. But the entity is a special purpose entity that's created by legislation in order for -- to assist Nova Scotia Power meeting its goals of renewables; correct?

A. (Williams) Absolutely.

Q. Right, right. And then another project that you mentioned earlier was the battery project. And that project, the Battery Energy Storage Project, that actually came to the Board as well. They received -- they received support from NRCan, which is a federal -- Natural Resources Canada. That funding provides up to one-third of capital costs of renewable projects. So in that case, a $355 million project, Nova Scotia Power was able -- that project was able to benefit to the tune of $115 million, leaving just a balance of 237 million. So basically a third of the project was provided by the federal government.

And that was a grant -- not even financing; that was a grant.

The Board decision in that matter, the actual decision approving it after the grant, was June of 2024. And I did a search in your report. I didn't see that report mentioned -- or that positive development mentioned, in the sense that that was a project that was able to proceed.

Am I right in that, and ---

A. (Coyne) I don't recall mentioning that in my report, Mr. Deveau.

Q. Right. Okay. But that would be another ---

A. (Coyne) Yeah.

Q. --- significant benefit, an example of -- Morningstar seemed to have a concern that, you know, the government -- the federal and provincial government are going to have to step up, but that's in two cases where they actually did step up. Is that correct?

A. (Coyne) And I see it -- I see it that way. You know, I've seen an evolution of a constructive relationship between the government -- the federal government, the provincial government and the company in working on this very difficult problem for the benefit of Nova Scotians. So I have -- there's no doubt in my mind around significant progress having been made in that regard.

The conclusion I can't step away from, though, is that Nova Scotia Power's in a different situation than Hydro One or Fortis BC Electric or any of the -- any of the Alberta utilities because they don't have that obligation at all.

Q. Right.

A. (Coyne) So we're mitigating a significant issue, in terms of transitioning that generation fleet, but that doesn't mean it goes away. But it is being addressed, and I view it as being addressed in a very constructive way.

Q. Right. I understand. I do understand that.

I ask these questions in the sense that -- in the sense that, obviously they were mentioned by Morningstar as a concern, and the concern was, hey, there's a lot of investment here and they're going to need federal and provincial assistance. And that's what you quoted in your report, but -- and perhaps the updated report, you know, will reflect it better. But in terms of what you presented -- and I know these rating agencies read these decisions, they do read the decisions and they're probably the biggest worriers. They worry about this stuff a lot in terms of assessing risk. And I think it's important that the record be clear that there are positive developments in terms of federal and provincial involvement in helping Nova Scotia Power transition to a clean transition.

A. (Coyne) And that's noted. I see that noted both by S&P and DBRS, so they've both noted those as positive developments.

I think the other thing that they take into consideration, you know, they are worriers in-chief as you described them. That's what credit rating agencies and debtors do. And -- but they come from a starting place of a triple B minus-rated utility, and that's not lost on them either. So these credit rating agencies see Nova Scotia Power as at the weaker end of the credit spectrum and they realize the significant investments that are going to have to be made, so that's something that they rightfully focus on.

Q. Yeah. And I agree with you. I agree with you, and my point in asking questions is just to confirm the fact because this -- I don't think it's on the record. There's not -- in terms of your report. There are positive developments that are following through on at least what Morningstar had said was what they were looking at.

Another example is securitization, so you have mentioned securitization, but just -- and I know there will be further questions on securitization in the fourth panel, but securitization, we are waiting for Regulations, or Nova Scotia Power is, in any event, but before that legislation -- those Regulations come in, there was actually amendments to the legislation in Nova Scotia to provide for securitization, which I would suggest to you is a pretty big step by the Province to recognize that, you know, that would be a possible avenue to help Nova Scotia Power. Is that a fair comment?

A. (Coyne) I see it as being

primarily to the benefit of Nova Scotians -- Nova Scotian electricity consumers because it takes an asset that's currently earning a rate base return on NSPI's books, securitizes it with a debt return paid over time, and has the net impact of lowering rates for customers. So I think that's a big benefit for customers.

Q. Right.

A. (Coyne) From an NSPI perspective, it lowers the debt on the balance sheet, that's also a good thing. And if ultimately it moves forward, as denoted by these companies, it's viewed as a positive from a credit perspective for the company, ---

Q. Right.

A. (Coyne) --- Mr. Deveau.

Q. Isn't one of the benefits of securitization that, again, it takes it off the balance sheet and it lets Nova Scotia Power deploy capital on another, I won't say, well, cleaner infrastructure in any event, so probably would be seen by rating agencies and investors as less risky investments?

A. (Coyne) I would think so.

Q. Compared to thermal plants.

A. (Coyne) I would think so.

Q. Right. Okay.

A. (Coyne) I don't know if -- Mr. Williams, I think, wants to jump in with a comment, I can tell.

A. (Williams) I do. And it's just -- I just want to reconfirm the record, as Mr. Deveau said, and I do agree with your point, sir, that it's important to make clear on this record where contributions have been made from important partners. And I wanted to make sure that the Board was aware of those two projects in particular, the BESS Project and the Intertie Project, were both referred in response to NSEB IR-54, ---

Q. Right.

A. (Williams) --- where it was -- they were raised and acknowledged as benefitting customers in helping to mitigate rate impacts for customers.

Q. Right.

A. (Williams) So certainly didn't want anyone listening in or reading after the fact to be under the impression that we had not acknowledged those. Those ---

Q. Oh, yeah. No, no, I ---

A. (Williams) --- projects are important, so...

Q. I know the company has acknowledged them on a lot of occasions.

A. (Williams) Yeah.

Q. My questions are more related to Mr. Coyne's report, ---

A. (Williams) Understood. Understood.

Q. --- because that -- you know, that's what -- in terms of the costs of capital, capital structure, that's what the credit rating agencies are looking at, and -- yeah.

A. (Williams) I know.

Q. And then the finial one in terms of support by the Province, and there are other examples, but in the -- and I can bring it up if you wish, but the Province, in terms of emissions, which you mention in your -- in that second bullet at the very end, that NSPI is exposed to risk for emission compliance, in March 25 of 2025 of this year, the Province also provided a variance which resulted in a revenue requirement reduction of $160 million in the test years. Granted, those emissions are deferred, but it is still -- it's still a sign, is it not, of the Province accommodating Nova Scotia Power's work it has to do in terms of reducing its emissions?

(SHORT PAUSE)

<u>MR. COYNE:</u> So Mr. Deveau, would you kindly repeat your question. I think I have an answer for you.

<u>BY MEMBER DEVEAU:</u>

Q. Yeah, I think my only question is that that is -- that variance that was able to defer some of the emissions compliance to future years, benefit ratepayers in the next two years to the tune of $160 million. And it's -- is it not a sign that the Province is prepared to accommodate Nova Scotia Power in its transition to cleaner fuels?

A. (Coyne) I believe so

Q. Yeah.

A. (Coyne) Yes.

Q. Yeah. And I think the premise behind, I think -- well, both the request, certainly the request, which is also in the record from, I can't remember who ---

A. (Williams) Mr. Pickles.

Q. Pardon me?

A. (Williams) Mr. Pickles.

Q. Mr. Pickles, yes. Was if we can defer those emissions to later years, then once the clean transition is in place we'll be better able to meet those emissions. So it's a recognition that the strict compliance that's in place, the Province was able -- was prepared to waive that recognizing that Nova Scotia Power would be better able to meet those emissions requirements in later years when the clean transition is further down the line.

A. (Coyne) Mr. Williams, did you want to comment?

Q. Yeah.

A. (Williams) No.

A. (Coyne) I think we recognize across the panel your point.

Q. Okay. So while we're at it, again, you have mentioned this, but the Province also -- in terms of the fuel, the Province bought the $117 million receivable, took that off the FAM balance, and there was also the $500 million federal guarantee so -- to remove that from the FAM balance.

So I haven't added all those up, actually, to prove any big numbers when you look at all of them together, but all that say that in terms of Morningstar's -- perhaps it's an open question or open-ended question, the federal and provincial government have been very accommodative in helping Nova Scotia Power, and that should be seen as a positive in terms of their business risks.

A. (Coyne) Well, two points I would make in response. You know, one is, it is January of 2024, the report that we had at that point in time, so many of these developments have been ---

Q. Right.

A. (Coyne) --- since then.

Q. But that's the one you cited, though.

A. (Coyne) I did.

Q. Right.

A. (Coyne) Yes, because that's the

one I had at that point in time, ---

Q. Right.

A. (Coyne) --- of course. And -- but they also start by saying that they're encouraged that there is now a plan for NSPI to achieve its mandated renewable generation targets, and there's alignment with the Province that substantial capital expenditures will be required.

So they go on -- they're concerned about these plans that require substantial funding support from both the provincial and federal governments under these ambitious timeframes. So they're looking at the longer term ability of the company to manage its financial capacity to make these investments in accordance with these arguably ambitious goals. So it's a challenge for a company the size and scale of Nova Scotia Power to meet these targets.

Q. Okay. Thank you. Those are my questions.

A. (Coyne) You're welcome.

<u>QUESTIONS FROM THE CHAIR</u>

Q. I don't have very many questions, but I'll start with you, Mr. Flemming.

Since the last General Rate Application, has Nova Scotia Power experienced any difficulties accessing capital on favourable terms to meet its needs?

A. (Flemming) Nova Scotia Power was briefly -- we had to apply for the exemptive relief to access the commercial paper program. That exemptive relief lasts until 2028. And so as of right now, we are active in the commercial paper program, and we have been able to access capital. We are mindful, though, of that 2028 expiration date for the exemptive relief for the commercial paper market.

Q. Okay. Mr. Coyne, again not very many, but I think the rest are for you. Just a couple of brief points, I think.

Your North American proxy group

included all of the American companies in your U.S. proxy group, but only three of the five companies in your Canadian proxy group. I'm just wondering if you could just explain why that was the case.

A. (Coyne) The reason I kept the three is that these three are primarily engaged in the provision of electricity, Canadian Utilities, Fortis Inc., and Hydro One. Albeit, Canadian Utilities also has a fairly substantial gas business, as does Fortis, but they're all involved in the electricity business, and that is not the case for Enbridge or AltaGas. So for that reason, I took those out of the five that I moved to the North American proxy group.

Q. Okay, thank you.

THE CHAIR: Mr. Goodine, if we could pull up an exhibit? It's one of the Excel documents. It's Exhibit N-8(i). Thank you.

BY THE CHAIR:

Q. Mr. Coyne, you may recall that in the NSPML hearing, we walked through these sheets and looked at some numbers using, from your North American proxy group, just the Canadian utilities that were on the list, and I just was asking you to confirm some numbers, if we excluded the American entities from those calculations. I appreciate, as I'd indicated in the prior hearing, that from your perspective, that's not appropriate; that, as I understand your evidence, it is not only inappropriate, but necessary to include the American data to give good results in your analysis and that if we restricted the analysis to just three companies, the pool would be really too limited to draw too strong a conclusion. So I know you have a number of caveats with the exercise, but if you'll indulge me, I'd like to go through anyway, just to get you to confirm those numbers.

THE CHAIR: So if we could just look first at the DCF, the Multi-Stage DCF tab, Mr. Goodine? CEA-5. So if we can just go to the top of the document?

BY THE CHAIR:

Q. See at the top we have your Canadian proxy group, that's obviously already Canadian focused, and the result of that analysis produced a return on equity of 9.6?

A. (Coyne) Yes.

THE CHAIR: And if we go down, Mr. Goodine, to, should be the third table down, the North American proxy group?

BY THE CHAIR:

Q. And if we were to just take the first three entities, the Canadian Utilities, Fortis Inc., and Hydro One entities on that list and just look at those calculations, by my math, it produces an ROE after the flotation adjustment of 9.07?

A. (Coyne) That seems about right.

Q. Okay.

THE CHAIR: And for the -- Mr. Goodine, the next tab, CEA-6, the Historical CAPM. Again, if we -- okay.

BY THE CHAIR:

Q. We see the Canadian proxy group there, which is 9.7 percent ROE based on that group. And then if we go down to the North American proxy group, again, if we're just to use the Canadian utilities, the first three rows, by my calculations, if we run the model, we get a result of 9.08 percent?

A. (Coyne) That seems about right.

Q. Okay. And your risk premium analysis is run separately for the Canadian and the U.S. entities, so we don't really need to go through the same exercise with that one; correct?

A. (Coyne) That's correct.

Q. And again, I appreciate you don't agree with the approach taken by the Alberta Utilities Commission, but in the Maritime Link hearing, I understood you to acknowledge that in their recent generic cost of capital decision, the AUC declined to use your model for risk premium analysis, because, at least in its view, it was not using what it considered to be market-based data to drive the result? Is that a fair recollection of your comment at that point? Or you agreed with me at that point?

A. (Coyne) Yes, I think so.

[2:29:56] **Q.** Okay. And one final thing, Mr. Coyne, you may recall you indulged me considerably, and I appreciated your response to whether there should be some sort of formulaic connection between the NSPML and Nova Scotia Power return on equity in that particular hearing. I have another sort of question, not specifically related to the numbers in this particular hearing, but cost of capital theory in general. And it’s along the lines of in the decisions that we’ve looked at from Alberta and Ontario, we’ve seen, of course they have much more utilities that they have to manage, but they have generic cost of capital proceedings every so often, and in the meantime run on a formula to adjust in the in-between years. What are your views on using a formula-based approach in-between full-blown resettings of cost of capital?

A. (Coyne) Well, it's an interesting question. We've done quite a bit of work on that issue. The BC Commission -- we provided a significant report to the BC Commission on this issue, where we studied the performance of the Canadian formulas in the various provinces over time. And what we found was that the formulas -- the earlier formulas adopted in Canada that were tied strictly to government bond yields didn't perform very well over time. And what we learned from tracking those formulas was that simple formulas tied to strictly government bond yields don't work well when equity markets move in different directions from government bond yields. And what we observed was over the course of two decades, as government bond yields went down as a result of fiscal policies on both sides of the border that managed inflation better than they had been previously, equity markets didn’t follow on a one-to-one basis. And that wasn’t really picked up in the models.

So, you know, our general views based on that study and just observation since then is that formulas work pretty well between rate cases, but when you try to rely on them for periods longer than five years, you run the risk that they get pretty significantly off track.

California uses it between generic cost of capital proceedings every three years, which I think is probably an even safer approach.

I think it’s a manageable amount of risk for up to a five-year period. We argued that point to the Ontario Energy Board and they’re in agreement in their most recent decision, that they’ll revisit the formula every five years.

So I think on the one hand, you have administrative efficiencies, you know, as much as I know Boards like yours enjoy seeing witnesses such as me and

Dr. Cleary come before you, there are other ways that you could use your time.

And so from an administrative efficiency standpoint, I think there are advantages going between rate cases with either a fixed ROE that's stipulated in the rate case, or one that varies with a formula that's not tied strictly to government bond yields.

The Ontario formula has a government and utility bond yield, so I feel better about that one. We were a part of that change back in 2009. And that's also the case with the Alberta Utility Commission's formula.

So up to five years, as long as it includes both the utility and a government bond yield, then I think it's manageable.

Q. Thank you very much, Mr. Coyne. Those are my questions. Thank you, panel.

THE CHAIR: I'll just go around to see if there's anything arising, first with the Consumer Advocate.

MR. MURPHY: No, thanks.

THE CHAIR: Small Business Advocate, none.

Industrial Group?

MS. RUBIN: No questions.

Thank you.

THE CHAIR: Municipal Electric Utilities?

MR. MacDOUGALL: Mr. Chair, Mr. MacDuff isn't here. There's no questions, but just for the record, I'd like to note he's not here because his wife is becoming a Canadian citizen this afternoon.

THE CHAIR: Well, extend to him our congratulations, and to her, I guess, more specifically.

MR. MacDOUGALL: Both of them. Will do, Mr. Chair.

THE CHAIR: Thank you.

The Port Hawkesbury Paper; same?

MR. MacDOUGALL: Same.

THE CHAIR: Renewall?

MR. ROSCOE: Yeah, a couple quick questions from me, please.

Thank you.

CROSS-EXAMINATION BY MR. ROSCOE

Q. A couple questions to follow-up on things that Mr. Coyne said and then Mr. Deveau said about the total amounts of fuel assistance over the last few years. I just wanted to clarify; you mentioned something very early on in this panel about the timeliness of FAM payments. Is it fair to say that prompt reconciliation of the FAM balances is a positive thing for the utility in reducing risk and their capital -- on their return on capital profile?

A. (Coyne) I would say so. And that's how FAMs typically work. Some clear quarterly, others clear annually. And I would think that anything longer than an annual clearance starts to cost the company in terms of lag. And, you know, that's assuming that there are negative balances. Of course if they're positive then they run in the other direction.

Q. Of course. Of course. And, in general, from a customer's perspective, because those balances occur interest, that it's also beneficial to the customers to have those balances addressed promptly as well?

A. (Coyne) Yes. And that's the thing with FAMs; they're generally deemed to be in the best interest both of customers and for shareholders for both those reasons.

Q. Excellent. I would highlight, from our perspective, we have a licence -- we're a licenced retail supplier here, which you may be familiar with, so we're competing with Nova Scotia Power at a retail level, and if they're not paying their full fuel cost, then that creates a barrier to competition from our perspective. So we have aligned interest in those FAM balances being paid promptly.

Mr. Deveau, you brought up the comment about the total amount of assistance, if I will call it, for the FAM over the past few years, and I thought it would be helpful for the record if those items were tabulated and summed. I believe that those items from March of 2023, $165 million, through, what I have called here a cap-and-trade forgiveness -- I don't know what the technical term is -- from March 2024, $117 ---

MR. CLARKE: Mr. Chair ---

MR. ROSCOE: I'm sorry.

MR. CLARKE: --- I guess we're allowed a little latitude with people who wish to ask questions, but I'm concerned about an individual giving evidence who hasn't been sworn in and isn't subject to questioning.

MR. ROSCOE: I can reframe this as a form of a question.

THE CHAIR: If you could, to the panel that would be ---

BY MR. ROSCOE:

Q. Is it possible to sum the total of the cap-and-trade forgiveness from March of 2023, the Invest Nova Scotia loan from 2024, and the federal loan guarantee from, I have here, December of 2024?

A. (Williams) So I'm not -- when you say sum them, Mr. Roscoe, I'm not entirely clear what you mean so I'll maybe get you to help me with that. But I just want to make clear that these are rate mitigation efforts, cost mitigation efforts, that have also benefitted, and would benefit, any potential customer of your entity.

Q. M'hm.

A. (Williams) Just so we're clear about what we're talking about here.

Q. I think I agree with that comment. The point of this, I think, is it comes to perhaps more of a topic for Panel 4 with respect to the accuracy of fuel forecasts and understanding the total amount of assistance or, I guess, payments from non-ratepayers towards the fuel balance, if you could call it that, is helpful to understanding the accuracy over the past five years.

A. (Williams) Happy to have that

discussion with that panel. But I guess my disagreement was with the premise of your question, which was that it somehow impacts your business case, because it does not.

Q. I think we can disagree on that. But I think it's helpful if the record shows the total amount of those interventions over the past few years.

A. (Williams) And I would suggest to the Board that this is rate procedure about '26 and '27 cost and rates.

THE CHAIR: I think those numbers are also sort of clear in the records from the Board from those proceedings as well.

MR. ROSCOE: Okay. Well, I'm just responding to a comment that Mr. Deveau brought up, and I think I thought it was helpful, and I was asking myself the same question, so...

[2:40:05] **THE CHAIR:** Thank you.

MR. ROSCOE: No further questions.

THE CHAIR: Thank you, Mr. Roscoe.

Did I miss anyone before going to Mr. Mahody and then Mr. Clarke?

MR. BOYLE: Department of Energy has no questions.

THE CHAIR: Sorry. Thank you. Apologies.

Mr. Mahody?

MR. MAHODY: No follow-up, Mr. Chair. Thank you.

THE CHAIR: Mr. Clarke?

MR. CLARKE: Nothing, Mr. Chair.

THE CHAIR: Thank you very much, Mr. Coyne. Again, thank you very much for your assistance in this proceeding.

MR. COYNE: My pleasure.

THE CHAIR: So we'll take our mid-afternoon break, I guess, at this point in time. It's 20 to 2:00. We'll come back at five to 3:00 and resume with Panel number 4.

--- Upon recessing at 2:40 p.m.

--- Upon resuming at 2:56 p.m.

THE CHAIR: Okay. Welcome back.

Mr. Clarke?

MR. CLARKE: Thank you, Mr. Chair. If you could swear in the panel, please?

JONATHAN MacINTOSH, Solemnly Affirmed:

CRAIG FLEMMING, Solemnly Affirmed:

BLAKE WILLIAMS, Solemnly Affirmed:

MICHAEL WILLETT, Solemnly Affirmed:

DRAGAN PECURICA, Solemnly Affirmed:

EXAMINATION ON QUALIFICATIONS BY MR. CLARKE

Q. Mr. Pecurica, you're the Director of Energy and Risk Management; is that correct?

A. (Pecurica) That's correct.

Q. And you've testified before this Board, including previous GRA, RTR matters, and FAM audit hearings; is that correct?

A. (Pecurica) That's correct.

Q. And can you remind the Board of your background and experience, please?

A. (Pecurica) I forgot to bring the printed copy. I apologize.

Q. Just one second.

(SHORT PAUSE)

MR. CLARKE: You could wing it, but we might be here for an awful long time.

MEMBER DEVEAU: Make sure I didn't change anything on there.

MR. PECURICA: Thank you. And I apologize for that.

Yes, I have a degree in electrical engineering from the University of New Brunswick. I'm a Registered Professional Engineer in Nova Scotia, and I hold the Energy Risk Professional Certification from the Global Association of Risk Professionals.

I've been with Nova Scotia Power for 25 years working in various parts of the business, including transmission, distribution, system planning, portfolio optimization, and energy risk management. I've been a part of the Energy and Risk Management Group for the past nine years.

MR. CLARKE: Mr. Chair, the general panel is ready for questions.

THE CHAIR: Thank you very much, Mr. Clarke.

Consumer Advocate?

(SHORT PAUSE)

THE CHAIR: Don't you two usually sit on the opposite sides? You're throwing me off here.

MR. ROBERTS: He's got the mic side.

THE CHAIR: That's right.

Mr. Murphy.

MR. MURPHY: Good afternoon to the Panel and good afternoon to the Nova Scotia Power panel.

CROSS-EXAMINATION BY MR. MURPHY

Q. So I do have some questions, and they're primarily, and really solely, about the PHP Above-The-Line Tariff Application, also know as the Extra-Large Industrial Dispatchable Tariff, or the ELID. And does the Nova Scotia Power panel agree that there remain a number of unknowns in relation to the ELID?

A. (Williams) I think we would agree with that, yes. I mean, obviously there's an Application and we've attempted to give the Board the full picture, but obviously the eventual outcome is yet to be determined.

[2:59:51] **Q.** Okay. Thank you. There were questions earlier to the cost-of-service panel about the -- page 6 of the ELID Application, where there's the dispute about the three coincident peak demand determinants applicable to PHP. And so I guess that's one area where PHP and NSP would seem to not be aligned, in terms of what Nova Scotia Power is proposing. Are there any other areas of the Application that you're aware of that PHP does not agree with?

(SHORT PAUSE)

MR. WILLIAMS: So we're aware of this one, obviously, and that's the one we've spoken of. I believe there would likely be some discussion at the hearing in this matter related to the interruptible credit as well.

Going further than that, Mr. Murphy, I'm hesitant to say. I don't want to speak for PHP up here. We've attempted to demonstrate where there is alignment, but I don't want to create unrealistic expectations or inaccurate expectations and speak inaccurately for PHP.

BY MR. MURPHY:

Q. And I guess on that point, the Settlement Agreement talked about the three coincident peak demand determinants, and Nova Scotia Power mentions in its Application that its position is consistent with the Settlement Agreement. Is PHP's position on the interruptible credit inconsistent with the Settlement Agreement, from Nova Scotia Power's perspective?

A. (Williams) I think to answer that, Mr. Murphy, I would have to make assumptions about PHP's position, and I don't think that's fair to them.

Q. Okay. Thank you. So at -- I believe it's at page 3 of the ELID Application, it states that:

> Should the Board not approve an ATL Tariff applicable to PHP, or should PHP determine it will not subscribe to the ATL Tariff as approved by the Board, an alternative course of action will be required for service to PHP in 2027. (As read)

And I'm wondering if Nova Scotia Power is able to say what that alternative course of action may be, number one, and how could that impact the GRA?

A. (Williams) I'll try to answer that in two parts. I think the first part, in terms of what it could be, I feel like I'm giving you a lot of nonanswers here, Mr. Murphy, so I apologize for that, but I think the reality is it would be dependent on the rationale for not taking service on it. If it was the result of changing conditions outside the regulatory context, if it was the result of the outcome of the regulatory context. I think all that would inform what the next appropriate path would be. The reality is that there's below-the-line and above-the-line, and it would need to be one of those two options. And we would certainly work to ensure there was something appropriate in place for them at the conclusion of the term -- the current term of the ELIADC, which is, as you indicated, at the end of 2026.

In terms of the second part of your question, what the impact would be on the GRA, to the extent that PHP is not taking service under an above-the-line tariff for any period within the test period, the '26/'27 test period, then the expectation would be that the difference between what the assumptions were and the revenue that would be obtained as a result of assumptions from PHP and what is otherwise being collected from them would be deferred and the appropriate mechanism to address that deferral would need to be also determined and would be dependent on the timing, the magnitude, the rationale for the decisions that have been made that resulted in the deferral.

Q. So lots of potential factors at play there.

A. (Williams) So yes, and I think all of the uncertainty that you and I are discussing here really just underlines the need for, and the importance for, the deferral. And I think as we discussed earlier yesterday, PHP is a very material, a very important, not just electricity customer, but entity within Nova Scotia, but as it relates to the electricity system, I think everyone's aware of its relative size and load on the system. And so any change in its circumstances we need to proceed, or any change in how it's treated, we need to proceed with caution, and we think the deferral is the appropriate mechanism to ensure that we're capturing the cost of service.

Q. Thank you. And this may fall into that earlier answer, but has PHP provided Nova Scotia Power with any sense of the criteria it would need to determine whether or not it will subscribe to the ELID Tariff?

A. (Williams) Over and above what is included in the Settlement Agreement, not to my knowledge, no.

Q. Okay. I guess one of the potential outcomes, I think you would agree with me, if they don't subscribe to the ELID is that they would stay on the ELIADC. And so just wondering if that were to happen, has Nova Scotia Power done any calculation on how that could impact the cost of service if the assumption is that PHP, in fact, remains below-the-line?

A. (Williams) Well, I think, if I'm

understanding your question, it was -- that relates to one of the undertakings that we provided to Ms. Rudderham in terms of delineating what the impact would be in the deferral context if they were to remain on the ELIADC for 2026. And subsequent to 2026, we would need to determine what that tariff was, what the baseline was for any impact.

Q. Okay. And I wasn't sure about that when I looked at the undertaking. It seemed to be specific to the deferral account and the true-up. And I guess my question is more how does it impact the cost of service generally if the assumption is PHP is below the line?

A. (Williams) So the cost of service has been done with PHP as above-the-line customer, and so that's what it's based on. The deferral was intended to capture anything that's different at a high level, anything that's different than that. To the extent that 2027, a tariff for PHP in 2027 differs from that, the cost of service that's imbedded in electricity rates that would be set today would -- my expectation would be that it would remain for 2027, but that the deferral would need to capture any deviations in that. Then a cost of service that's established subsequent to 2027 would incorporate whatever the new PHP tariff may end up being.

Q. Has Nova Scotia Power, does it have a Cost-of-Service Study that assumes PHP is below the line?

A. (Williams) We would have not a final version with them below the line. I think, as you'll probably recall, there were a number of moving parts and iterations as the Application was being finalized before filing, and so there wouldn't be a final cost of service that has all of their assumptions and all their treatment correct with PHP below the line, there were other things that would have changed as well. So nothing that would be as we are today, but PHP below the line.

Q. And I guess just the reason I'm asking is I'm trying to get some certainty -- some sense of certainty about what the potential outcome could be whether it's phrased through the vehicle of a deferral account or whether it's simply, you know, here are the two different cost-of-service models and how that could impact the residential class. So I think that's the kind of information we're looking for.

A. (Willett) So I think to be helpful, there's a tab within OR-1, Attachment 1. It's a PHP tab, and it has PHP's revenues as them being a below-the-line customer and them as an above-the-line customer. That might give you some of the information that you're looking for. But it wouldn't be a full cost of service with them as below the line.

Q. Okay. But I take it, though, Nova Scotia Power's view is there's not a lot of information about the deferral account and how it works in the Application. So -- but the -- what you're saying is the deferral account will account for any differences that would arise as a result of the different treatment between PHP being above the line versus below the line.

A. (Williams) The short answer to that would be yes, Mr. Murphy. I think just to add, that one of the significant variables that has the potential to create an impact if -- as a result of this discussion between below the line and above the line is the advent of Goose Harbour Lake and the change in load.

Q. Thank you.

The Application ELID, and again I appreciate some of these issues will be explored in that separate Application, but it refers to a proposed dispatchable rider. And I’m just -- is this something that is in the Consensus Agreement, or is this a new term, a new development?

A. (Williams) That's a -- it's a good question. It's the same question I had when I first read this. It's the -- it's effectively ADC, so Active

Demand Control, just by a different name. So it is, to answer your question more directly, it is included in the Settlement Agreement. It's the same concept that was contemplated there, just ---

Q. Okay.

A. (Williams) --- a different name.

Q. Just a new name for the tariff.

A. (Williams) New name for the tariff, new name for the rider, yeah.

Q. Yeah, okay. Thank you, those are my questions.

A. (Williams) Thank you.

THE CHAIR: Thank you.

Small Business Advocate?

MS. MacADAM: No questions.

Thank you.

THE CHAIR: Industrial Group?

MS. RUBIN: We do have questions. My colleague has just run to the bathroom and will be back imminently, so I'll set up while she ---

THE CHAIR: Okay, thank you.

MS. RUBIN: --- until she returns.

(SHORT PAUSE)

CROSS-EXAMINATION BY MS. RUDDERHAM

Q. Good afternoon. I'm going to follow up on a few of the questions that my friend was asking about the PHP matter.

First, I want to start by asking a few questions about the PHP deferral.

MS. RUDDERHAM: So Mr. Goodine, if you don't mind pulling up the Application, Exhibit N-3, PDF page 80.

BY MS. RUDDERHAM:

Q. I can give you just a moment to familiarize yourself with this section of the Application, but this notes that PHP is requesting approval for the deferral account, which is referred to as the PHP deferral, and then it lists a number of scenarios to be covered by the deferral.

Fair summary?

A. (Williams) Other than I think -- you said PHP is requesting it. It's obviously us ---

Q. Oh, sorry. I meant to say NSP, yes.

And the three bullets there, those are based specifically on terms reached in the Settlement Agreement or Consensus Agreement; correct?

A. (Williams) Generally, yes.

Q. When you say "generally", what do you -- like it's just paraphrased, or...?

A. (Williams) I haven't done a side-by-side comparison as we sit here, but the intention was to replicate, obviously, what was in the Settlement Agreement.

Q. Okay. Thanks.

I just wanted to walk through some of those scenarios that are listed there.

So bullet 1, it says, "the Board's decision on the PHP tariff or ADC rider differs from the assumptions in the GRA."

You see that there?

I see you nodding yes, but I assume you just ---

A. (Williams) Yes.

Q. Okay. Thanks.

Now, that -- this section I'll try and summarize what I believe that it contains.

It relates to variances arising from things like the interruptible credit assumptions that are used in the cost of service; correct?

A. (Williams) That would be included there, yes.

Q. And it's currently modelled using a credit that's equivalent to be a credit for large industrial, the large industrial credit -- interruptible credit, sorry.

A. (Williams) Correct.

Q. Okay. That also would include the variance that may relate to a priority interruptible credit?

A. (Williams) Correct.

Q. And that's currently modelled at 10 percent; correct?

A. (Williams) Ten (10) percent of the interruptible credit.

Q. Yes.

A. (Williams) Yes.

Q. And so whether there's any priority or not or if it's increased or less, that would be covered by the deferral.

A. (Williams) Yes.

Q. Okay. There's also reference to an ADC rider.

And that would relate to any variance in relation to any ADC credit or, as I understand it, dispatchable credit that's included in the ELID or Application; correct?

A. (Williams) Correct.

Q. And currently, there's no ADC

credit model in the Application or dispatchable credit model in the Application.

A. (Williams) That's correct. There's no -- there's no -- I'll just use that. That's correct.

Q. So I guess just to clarify, there's no value associated with a credit going to PHP.

A. (Williams) That's where I was going to add, but that's correct, yes.

Q. Okay. But the fuel is still forecast assuming there is that ADC operation; correct?

Sorry; fuel amperages power, is what I meant.

A. (Williams) Yes, that's correct. There's the assumption that there's a benefit from ADC in the fuel forecast.

Q. Okay. So fair to say that this bullet here would include any variances to the assumptions that are included in the Cost-of-Service Study that relate to also PHP's load or demand.

A. (Williams) Yes.

Q. Sorry. And what I referred to is that 3CP debate that we kind of talked about yesterday.

A. (Williams) That would be included in that, yes.

Q. Yes. Okay.

Looking at bullet 2, then -- no, sorry. Before I move on, what I've listed to you, that would be what's covered under that item; correct?

A. (Williams) That would -- those would be items that would be included in there. I -- as we sit here, I don't think I would commit that that is an exhaustive list of items, but they all -- they all are included in there, yes.

And I say that not because I have something specific in mind. I just am hesitant to say that's exhaustive.

Q. But you'd agree with me, though,

that if -- the Board and stakeholders would need to know what specifically or at least what categorically would be captured in a deferral account to be approved; correct?

A. (Williams) Correct. And I think, as we've discussed, the baseline would be what's collected today as compared to what would be collected under the tariff. And so an example, Ms. Rudderham, that is not necessarily something you and I discussed, but that is a concept that I believe is included in the Application is a -- let me find it -- is a customer charge, so an additional charge to PHP that perhaps is not included what you and I just spoke about.

Q. When you say, "customer charge," what do you mean?

A. (Williams) I can try and help you.

Q. Yeah. I'll ---

A. (Williams) So what I'm getting at is charges specific to them, the operation of the tariff, that type of thing, and those may be incremental charges that we don't need to include in a deferral, but I think there's just -- my hesitation to say that it's an exhaustive list is just we need to let the process play out and understand exactly what the cost differences could be under any ELIADC scenario as compared to whatever the eventual scenario is with the approved tariff.

Q. As I understand it, there'd be a $10,000 per month customer charge on the ELID. That's what's modelled currently; correct?

A. (Williams) I'll take that subject to check, yeah.

Q. Okay.

A. (Williams) Ms. Rudderham, Mr. Willett is just correcting me that that's what's proposed in the Application, not what's modelled in the GRA, so just a distinction to make sure it's clear.

Q. Okay. So then what's been modelled in the GRA?

A. (Williams) I don't believe there would be any costs related to that in the GRA.

Q. Okay. So you're saying it's an additional cost beyond what's in the GRA.

A. (Willett) Yeah, additional revenue requirement in order to administer and also the collection of it. So from that standpoint, there would be additional cost, but the recovery would be coming from the tariff.

Q. Okay. So then other than what we've discussed, you're not able to point me to any other categorical costs that would be captured in the deferral account.

A. (Williams) Not specifically, other than to say the deferral is intended to capture the difference between revenue that would be collected as -- under a below-the-line tariff, the ELIADC, as compared to an above-the-line tariff.

Q. Are you suggesting it would cover any and all, or just what's been specifically included in the Application and in the Settlement Agreement?

A. (Williams) Well, I'm suggesting any and all. When we talk about bullet 1, any and all differences between what's been modelled and what's been -- or what's been modelled and assumed and what is the eventual tariff.

Q. Okay. I'll move on to bullet 2 there, then.

It says, "The tariff is not available for PHP to take service under it as of January 1, 2026." See that there?

A. (Williams) I do.

Q. Now, that relates specifically to a variance of time as to when the tariff would be approved; correct?

A. (Williams) Correct.

Q. So it's a true-up of -- from when PHP is being served on the ELIADC to the time that it would take an above-the-line tariff?

A. (Williams) No, it would be -- so as I would interpret bullet 2 -- and we have to remember that everything is written as of rates January 1, 2026. So the assumption would be rates are in effect January of 2026, but the tariff is not in effect until some time thereafter.

Q. Okay. And then the third bullet there it says, "PHP determines the outcome of the ADC and tariff processes is not satisfactory."

A. (Williams) Yes. And so read together, I think bullets 2 and 3 what they're both really driving at is providing for deferral costs that, to the extent there is any period in '26 or '27 where new rates are in effect that are assuming PHP is above the line but they have not either been able to take service under the tariff or they elect not to take service under the tariff for any period during that '26-27 test period, then those two bullets are aimed at capturing that or those scenarios.

Q. So it's fair to say that what's listed here are they're intended to set the parameters for this PHP deferral account that NSPI is seeking approval of.

A. (Williams) As best we can. And as, you know, the discussion you and I are having proves, it is a little broad, and I acknowledge that, but it acknowledges the uncertainty of moving forward and trying to take, as I said, that cautious approach to make sure that we're not taking steps that will unintentionally harm customers of the utility.

MS. RUDDERHAM: Okay. Mr. Goodine, if you don't mind pulling up from matter M12661 Exhibit N-1 that I had sent to you the other day, and specifically page 14.

If you don't mind scrolling down just a little bit so we kind of straddle 14 and 15. There, yeah. You can scroll slightly up just so that you see the end of the bullets there.

<u>BY MS. RUDDERHAM:</u>

Q. So what we're looking at here is the ELID application that was filed by NSPI in Matter M12661. Can you just confirm that?

A. (Williams) Yeah, I confirm that.

Q. Okay. So what we're looking at on this page is specifically in relation to the PHP deferral. And I am starting at line 20. It says:

> However, the PHP Deferral recognizes the material [differences], both positive and negative, which may arise between assumptions for ATL service [above-the line-service] to PHP in the GRA and what will actually unfold in the coming months including, but not limited to, the following:...

And then it lists a number of scenarios. Do you see that there?

A. (Williams) I do.

Q. Now, you agree with me that the list provided in this application doesn't track the same language from what's being applied for in the GRA; correct?

A. (Williams) No, I don't agree with that. Certainly the language doesn't track in terms of it's not the same words, but the intent is the same. And I think you and I talked about the first bullet in the previous discussion we had of the three bullets.

I would think that certainly the vast majority -- I haven't gone through each of these bullets, but the vast majority of these would be captured under that bullet and then, as I said, bullets 2 and 3 are really about the timing. And when I'm referring to 1 and 2 and 3, I'm talking about the previous three bullets.

But I do think this is consistent with what's conveyed in the application.

Q. Okay. Maybe we could just go through some of the bullets here, then.

A. (Williams) Certainly.

Q. So the first one is the cost-of-service model applicable to NSPI above-the-line customers, the classes. Bullet 1 from the GRA is I assume what you're referring to.

A. (Williams) Correct.

Q. The costing and billing determinants applicable to PHP, bullet 1.

[3:30:03] **A.** (Williams) Correct.

Q. The form of tariff construct including pricing of the tariff elements as ultimately approved by the Board, you're saying that's bullet 1.

A. (Williams) Correct.

Q. As applicable, the form and terms of the Board approved dispatchable rider, or ADC rider, interruptible rider, and priority interruptible rider, that's what we discussed for bullet 1.

A. (Williams) Yes.

Q. Now, this one says -- the next one says the timing and energy production from the PHPW, which is the wind, PPA during 2026 and 2027. Now, I don't see that. That wasn't discussed in our discussion of the deferral in bullet 1, bullet 2 or bullet 3. Do you agree with that?

A. (Williams) No, you had referenced the load and demand of PHP in our discussion, and I had agreed to that.

Q. Okay. I had clarified what I had meant was 3CP debate about load and demand, whether it's at 65 or whether it's at eight.

A. (Williams) And I had said that I agreed that would be included in the load and demand.

Q. Okay. So you're saying that timing and energy production from the Goose Harbour Wind Project would be built into this deferral.

A. (Williams) Yes. It's a significant component of PHP's service over the test period, and it would be a fairly significant assumption that was built into the GRA in terms of when that wind farm would be coming online and when PHP's load would shift as a result.

So to the extent that that timing moves forward or is delayed or the full implementation of that wind farm is delayed or accelerated as well, that has the potential to have a very material effect on the revenue that's collected through electricity rates, and that has the potential to create a positive or a negative effect on the deferral depending on the direction of that timing.

Q. Okay. And I guess just for clarity, on bullet 1 -- and when I say bullet 1, I mean from the GRA -- you were looking for -- looking to defer any Board ordered changes to the cost-of-service model. Is that what you were looking for?

A. (Williams) Yeah, so I think the wording from the bullet is the Board's decision on the PHP tariff rather differs from the assumptions in the GRA. And then one of the assumptions is, as I said, certainly the uptake of load or the advent of Goose Harbour and the resulting impact on load of PHP.

Q. Okay. So just to confirm, that variable wasn't actually carved out in the Consensus Agreement, was it, as part of the deferral?

A. (Williams) Well, I -- so I certainly believe it was, or we wouldn't be taking this position.

So when you look at the Consensus Agreement under PHP treatment sub (b) -- and I know the way we've numbered this is not helpful, but sub (b) and then sub (c) is PHP energy will be based on PHP's forecast usage for the test years now that the amount forecast to be provided by the Goose Harbour Lake Wind Farm, and that bullet begins with, "The cost of service has been prepared on the basis of the following PHP load characteristics". And that includes the 65 as well as the eight

And then the third bullet (c) is the Goose Harbour side. I think it's all part and parcel of the same thing.

Q. I guess just so I'm clear, any risk of the Goose Harbour not coming on when it was anticipated or coming on before -- or NSPI is looking to mitigate that risk through this deferral account charged to other above-the-line ratepayers.

A. (Williams) So I think, as I said, it could go both ways. So it's not necessarily the risk. The deferral could be impacted positively or negatively.

But again, there's a benefit to all these other ratepayers or customers as a result of PHP coming above the line. And so it's not necessarily the case that it's a risk that's being downloaded, as you're kind of characterizing it. It's just a cautious approach to ensure that as we bring PHP on, which in and of itself is a very significant move, to bring them above the line. And then that's coupled with, as I said, the introduction of Goose Harbour.

So those are two very significant variables that have the potential to impact the cost of service. And when I say the cost of service, I mean the costs that are collected through electricity rates in a material fashion.

And so again, we think the deferral is an appropriate mechanism. And I certainly acknowledge that Bates White, I believe, has also recognized it as such, as an appropriate mechanism to address those risks and ensure that those significant variables are not negatively affecting parties.

Q. Okay. And I guess the same goes for the next bullet down, "PHP's consumption over period 2026 and 2027."

A. (Williams) Yes, and I think those go ---

Q. Hand in ---

A. (Williams) --- hand in hand with the bullet I had where we're really talking about PHP's consumption when we talk about Goose Harbour.

Q. And then the last two are just in relation to timing, bullet 1 and 2, and whether PHP actually takes an above-the-line tariff.

A. (Williams) I'd agree. To use the ---

Q. Two (2) and 3, sorry.

A. (Williams) Yeah, the points of reference you've been using previously, they'd be points 2 and 3 from the GRA.

Q. And in this application I had read in, it says, "including but not limited to the following". Are you saying that there could be other costs?

A. (Williams) Yeah, I think this goes back to the discussion we had previously. You know, limited to -- or including but not limited to, those are the ones that, you know, come to mind for me right now, but I don't know what the eventual outcome could be of the tariff and there may be others that were simply not -- not front of mind right now or not able to think about right now.

It’s -- the language is not worded such that we have other thoughts or other potential issues that may arise. It’s just to acknowledge the fact that, you know, we’re going down somewhat uncharted territory, and we want to make sure that we’re remaining -- we’re leaving the question open for discussion.

But again, Ms. Rudderham, I would view this as being 100 percent consistent with the Application and with the Settlement Agreement.

Q. Okay. And just to clarify, other customer classes are responsible for load variances and true-ups of FAM costs; correct?

A. (Williams) I think I understand what you’re asking, but could you just ask me one more time, please?

Q. Other customer classes are responsible for load variances and true-ups of FAM costs; correct?

Above-the-line customers.

A. (Williams) Yes, and that, really, the deferral -- I think what you're getting at is the deferral is really just a non-fuel deferral because most -- the fuel costs can be addressed through the FAM? Is that ---

Q. I guess I'm asking -- yes.

A. (Williams) That would be my view is that, you know, the fuel costs would be addressed through the FAM mechanism. Really, the deferral is applicable to non-fuel costs.

Q. So this is a deferral for any and all non-fuel costs related to PHP either going above the line or not? You're -- NSPI is applying for a deferral to cover any and all costs regardless of what they look like now or at a later time that they're incurred.

A. (Williams) Yeah, I don't know that I would say any and all regardless of when they're incurred.

Q. Over the next two years.

A. (Williams) Yes, certainly within the test period, but when you say any and all, I think we've gone through the list.

And I take your point that we're saying is included but not limited to, but I think we've established what the principles are of what would be included, so I don't know that I would agree to the contention of any and all, in fairness to the Settlement Agreement.

[3:40:01] **Q.** I guess I'm trying to clarify what exactly NSPI is looking for approval from the Board for for this deferral account because there needs to be some predictability here as to what's going to be deferred and recovered at a later time versus what is not going to be deferred and recovered from other customers. So can you clarify that?

A. (Williams) Yeah. Well, I'm trying to. And I understand the frustration, but I think the reality is that we need to ensure we're not closing the door to something that we just may not be seeing or foreseeing as a result of this tariff application.

I do think we have put forward appropriately worded, appropriately stringent criteria as to what would be applicable or what would be eligible for the deferral. And it goes back to -- when I say principles, it's really those three bullets from the settlement -- or three bullets from the General Rate Application that are based on the Settlement Agreement and then we've expanded on those, expanded on those here in the PHP application to try to give a bit more clarity as to what those items could potentially be.

Q. Okay. So I guess what I'm trying to clarify here, then, is NSPI is not applying for an expanded scope of the deferral account in this separate application from what's been applied for in the GRA. Is that what you're saying?

A. (Williams) No, and nor are we

trying to expand what was agreed to in the Settlement Agreement.

As I said, we see that all as being -- as a consistent passthrough from the Settlement Agreement to the General Rate Application to the PHP application.

And I think, Ms. Rudderham, when you look at other deferral accounts, you know, one example of it would be the storm rider. We're deferring broad costs, and you don't know exactly what would be in that. You can collect them in the deferral, but what actually is eligible for recovery out of the deferral is up to the Board and the Board's discretion. So you don't know exactly what costs and what kinds of costs and what types of costs you'd be collecting until the event has happened and then you make the determination as to what's appropriate for collection or that deferral.

So I see it as, you know, somewhat similar in that respect. But it's very difficult to firmly delineate what exactly the cost will be.

Q. Okay. So you're saying when you go to recover it, there will be a review of whether those costs should or should not be included in that deferral account?

A. (Williams) Oh, absolutely. Yes.

THE CHAIR: Ms. Rudderham, can I jump in here for a second?

MS. RUDDERHAM: Absolutely, Mr. Chair.

THE CHAIR: Mr. Goodine, could you pull up Exhibit N-27 and go to IR-130, please?

And Mr. Williams, I may not have been following the threads of the conversation here, but I'm just -- I'm perceiving a little bit of a discrepancy, and I may just not be understanding the nuance of -- I'm just wondering if you could clarify the response here in this IR. So in 130(a), Nova Scotia Power was asked to:

> ...confirm, or explain otherwise, that the potential variances [for the PHP deferral] relate to differences in the assumed and proposed tariffs, and not for revenue variances for other reasons.

If you go on to the response, it's on -- I'm really focusing in on the last line in the response in (a). It says:

> The Company can confirm it is not Nova Scotia Power's expectation that variances arising from differences in forecast energy or demand volumes compared to actuals would be deferred.

How does that relate to the discussion that you and Ms. Rudderham have been having?

MR. WILLIAMS: Yeah. No, I appreciate the question, sir. It's a fair one.

I think the intention here was to address normal course variances. And so the wording, to your point, is not helpful in this discussion in that it's not as clear as it should have been.

But certainly we're not attempting to alter the Settlement Agreement or what was applied for here. We're seeking to just confirm that we're not expecting to true-up normal course variances that may occur throughout the year just as a result of normal business operations. But certainly material aspects of PHP’s operations such as Goose Harbour Lake where there could be, as I said, a material impact, significant impacts to revenue, those were intended and those were material assumptions that went into the cost of service.

THE CHAIR: Thank you.

Sorry, Ms. Rudderham.

BY MS. RUDDERHAM:

Q. That was actually my next reference in there. But I did want to clarify, this does look like a change in expectations. Has there been a change in expectation as to what will be included in the deferral account from the time that this IR response was completed to the time of the ELID Application?

A. (Willett) No, there absolutely has not been, Ms. Rudderham. As I said, it's -- you know, it's simply the response could have used a few additional words to clarify the point I just made.

Q. You used the terminology, I

think, "material aspects" and "material assumptions," and I just want to get some clarity, I guess, to explain how NSP is going to distinguish between the tariff-related variances that are deferrable and volume-related variances that are deferrable and which that are not.

A. (Williams) Yeah, and it's a -- I think it's another good question, Ms. Rudderham, and I -- from our perspective, when I say, "material" I think what I'm -- and I when I say "normal course" versus "non normal course" what we have in mind is Goose Harbour, in particular, as we've discussed, and then obviously any material or significant impacts to PHP's operations. But certainly not, as I said, normal course deviations that would occur on a regular basis or semiregular basis.

Q. At this point in time, does NSPI anticipate any variances arising from the different -- from the forecast energy and demand volumes compared to the actuals that will be deferred? Like, is there any anticipated variance at this point in time?

A. (Williams) Certainly, the 3CP and the difference between the 65 and 8 would be something that we're aware of and we've discussed, but other than that I'm not aware of anything at this time.

Q. What's the current assumption as to when the Goose Harbour Wind Farm will be online and serving that's built into the Application?

A. (Williams) The cost-of-service assumption in relation to Goose Harbour is Jan 1, 2027.

Q. So you have no better information at this point?

A. (Williams) I don't have anything more definitive, no.

Q. I'm going to switch topics, which I'm sure you're happy about.

Throughout the hearing, we've been hearing a lot of discussions about the impact of the general rates on the domestic and residential class. And I assume you accept that the rates that are applied for within this proceeding does show a different impact towards the domestic class as compared to some of the other rate classes. Is that fair?

A. (Williams) Yes.

Q. But you can confirm for me that the rates that are applied for in this proceeding don't represent a full picture of the rates that are actually going to be charged within 2026 and 2027.

A. (Williams) Yes. So, apologies, the -- this Application obviously represents general rates. There's riders that would be applicable also in -- or have the potential to be applicable also in '26 and '27. In '26, there will be a -- there will be DSM riders in both years, '26 and '27. We've talked about the storm rider briefly previously. There's not the expectation that there would be, well there will not be a storm rider in '26, and there's not the expectation that there would be one in '27.

There will be a securitization rider

when that comes on, and the cost apportionment of the cost related to securitization is, as we've previously discussed, yet to be determined, but it is expected that it would be in place during the test period. And then, obviously, there is an AA/BA rider, an application, that is -- that will be forthcoming before the Board that will address outstanding fuel costs.

Q. Okay. I just wanted to walk through a couple of those additional riders that you referenced. Storm rider, you said there's not going to be one for 2026, but there is one for the DSM rider; correct?

A. (Willett) There is a 2026 DSM Rider Application in front of the Board currently awaiting a decision.

Q. Yeah. That's Matter M12521; correct? Subject to check, ---

A. (Willett) Well, ---

Q. --- I guess.

A. (Willett) --- subject to check,

yes.

Q. So NSPI knows what the riders would be, assuming that the Board approved it as filed; correct?

A. (Willett) That's correct.

Q. And you could provide, I guess, the impact to the 2026 with that rider for the purposes of understanding the full impact for 2026 in this proceeding.

A. (Willett) I think within the Application you can see by customer class what the impact is, so it shows that within the Application.

Q. Okay. And for the AA/BA, you're referring to the FAM AA/BA rider, which is a true-up of the FAM costs; correct?

A. (Willett) That's correct.

Q. And there’s a current -- there was an interim application for the FAM AA/BA in relation to the 117 million Invest Nova Scotia, and then the 500 million FLG; correct?

A. (Willett) That's correct, but I would just note those were items that were extended, so there was no impact on rates related to those as they were already in place.

Q. Okay. And NSPI, as you've mentioned, hasn't applied for the full FAM rider yet; correct?

A. (Willett) That's correct. As part of the Settlement Agreement, there was provisions within the agreement to work with certain customer classes on the balances that were outstanding for those classes in recognition of those amounts for those specific classes. And so the company has been doing that work with those customer classes throughout the fourth quarter of 2025.

Q. Okay. And that balance, you're referring to the total balance as of Q3, it's 66.9 million or 67 million; correct?

A. (Willett) Subject to check, but that rings a bell to me. It's in that ballpark.

Q. Would NSPI be able to provide an indicative FAM AA/BA for 2026-2027?

A. (Willett) I just want to make sure I understand what you're asking for in that. Are you asking for what the cents per kilowatt hour would be, or are you asking for what the expected increase, percentage increase on rates?

Q. Yes, I want to do the -- I want to do a comparison as to the impact on general rates, which is included in the Application, I think Figure 2.2 or 2.3, which is the impact to 2026-2027. I want to understand what the impact is with the riders.

A. (Willett) Maybe it would be helpful to -- I'm thinking you might mean 2.1, but maybe we can just confirm which figure you're referring to and bring that up.

Q. I may have misspoke on that. Let me just pull it up here.

It is 2.1, I think. My friend just

whispered that to me.

Yes. That's PDF page 16 of 99.

A. (Williams) So Ms. Rudderham, the DSM rider is on the record in that proceeding in terms of what the rate impacts would be. As I discussed in relation to the securitization rider, we don't have the information to do that in terms of what the cost of service may be, what the rate would be, what the timing of that would be so I don't think it's practical to do such a comparison in relation to that.

Certainly in relation to fuel, as I said, we do have an application forthcoming. I don't think we're in the position to put on the record in a proceeding what the percent rate increases would be, but we can certainly speak to them generally, if that's helpful.

And maybe I can -- I know when we talk about the balancing, sir, that was undertaken in the Settlement Agreement, certainly the cost of fuel and the

AB rider during the test period is a component of that balancing. Even though it’s not part of this Application, it’s something that parties were discussing and aware of.

And the impact of that rider will be not exactly, but it will be effectively the inverse of what the rate increases are here. And by that, I mean when you look at the relative rate increases for the different classes of customers in this proceeding, we anticipate that those that are getting the larger rate increases in this proceeding will have the smaller rate increases in relation to fuel. And conversely, those that are getting the smaller increases or even decreases in this proceeding will be getting the larger increases in relation to fuel. And so that is, I think, part of the tradeoff that was -- or balancing that was part of the equation in those discussions.

MEMBER DEVEAU: Isn’t that -- doesn’t that really provide a stronger reason why we should now see them, to be able to do a fully review of the impact of the rates in this matter?

MR. WILLIAMS: A stronger reason to see them?

MEMBER DEVEAU: Yes.

MR. WILLIAMS: Well, I think ---

MEMBER DEVEAU: Wouldn't it be more important to see the total picture?

I mean, it's a known amount. You just haven't allocated it and discussed timing of collection. So we know -- you'll know what the balance is.

MR. WILLIAMS: We do know what the balance is.

MEMBER DEVEAU: Right. So in order for the Board to properly assess this particular Application in terms of any rate shock or other rate considerations, wouldn't that be a useful piece of information to have so we can assess this Application?

MR. WILLIAMS: I don't -- so I guess from our perspective, sir, the General Rate Application stands on its own. The assessment of that and what's appropriate is contained to this Application.

The collection of the fuel costs would be a separate proceeding and whether the collection timeline for that needed to be altered as a result of the decision here would be something the Board could determine as part of that proceeding, I suppose. But I don't see them as needing to be dealt with together for the same reason that the DSM rider doesn't need to be part of this proceeding or the storm rider wouldn't need to be part of this proceeding or other riders, so.

[3:59:45] **MEMBER DEVEAU:** I guess -- I don't know if you read the letters, but I read the letters that come from the public, and I'm sure you do read them. People -- it's fine to say this particular application and that particular application, but people are really sensitive to hearing about a rate increase on January 1st for DSM, a rate increase, another rate increase for a rate application, another increase later on for storms or anything else, the securitization.

People, you know, they don't -- you know, they don't budget on, you know, what am I going to pay for this rider or this rider or general rates. They want a global -- you know, they budget based on a total figure. And in my view, it's important to know as best as possible what that total figure is.

That's what the average Nova Scotian and average business owner in Nova Scotia is basing, you know, what the impact of power rates are. They just don't look at a part of it. They look at the total package.

MR. WILLIAMS: Yes, sir. And I've read every one of the letters and I've not just read them, but paused on them and give them quite a bit of thought. And it goes into what we do and what we've brought forward here today. It is meaningful. And I understand the concern.

And one of the initiatives that we've raised with stakeholders is just that, in bringing forward a more consolidated approach to the DA, DSM, storm rider that's not before this Board today, the proposal, or such an application, but what we would like to do is consolidate those so that we're bringing them forward collectively so that they can be assessed collectively.

So we are being responsive to that type of concern. We understand that concern.

Here today, I think we're offering this information in relation to fuel because it was meaningful in terms of the balance that was struck, but I don't see it as being needed to be determined as part of this Application.

MEMBER DEVEAU: I got the sense Ms. Rudderham was asking you because she wants to know. I mean, the Chair will have to decide. He may ask Mr. Murphy and I if Ms. Rudderham wants the undertaking or not, but I guess you've got a class of customer here that wants to know what it is if she does ask for it. And so we'll have to decide.

So you're saying you don't think it's -- I'm not quite sure why you don't think it's germane to this particular Application. I know it's a different application, but it's a pretty big part of what ratepayers are going to pay. I mean, this -- I think it's 50 -- 60 percent of the cost or so for fuel.

MR. WILLIAMS: Yes. And ---

MEMBER DEVEAU: And I realize part of the fuel is in -- is already in here, but.

MR. WILLIAMS: And I guess what I'm suggesting, sir, is that we have the -- I understand Mr. Rudderham's role and who she represents, and the customer representatives that are in this room were all part of the discussions that I'm describing to you, so they are all aware of these costs. They all participate in this FAM Small Working Group.

MEMBER DEVEAU: The Board wasn't in the room, though.

MR. WILLIAMS: No, I understand that

and that's why I raise it here today, to make sure that the Board is aware of the consideration and the thought process that went into that.

BY MS. RUDDERHAM:

Q. Maybe it would be helpful if you could give an order of magnitude as to what the impact would be on the large industrials and medium industrials for 2026-2027 so to better understand the context behind the Settlement Agreement.

A. (Williams) Ms. Rudderham and Mr. Deveau, I'm trying to be responsive to both of you here.

Why don't -- would it be acceptable if we took that away as an undertaking and prepared something so that the Board and Ms. Rudderham had that better information before them to assist in making, the Board, their decision, and Ms. Rudderham, informing her position?

Q. I'm fine with it being taken away. I just want to make sure that there's a more clear picture so that if things were to be taken out of the

Settlement Agreement, it would show a full picture as to how this will impact our customer class.

THE CHAIR: I think that would be helpful, Mr. Williams. I'd assume you'd do it for all rate classes, not just the large industrial and the medium industrial that Ms. Rudderham spoke of.

MR. WILLIAMS: Yes, I think in order to demonstrate the point in which I'm trying to make, that would be helpful.

THE CHAIR: Okay. And so if you could just articulate, just for the record, so we can give it a formal undertaking number, what you're going to provide here, that would be helpful.

MR. WILLIAMS: Maybe give me one moment to get my words together.

THE CHAIR: Sure.

MR. WILLETT: If I were to repeat what I think the undertaking is, is to provide an order of magnitude impact of the AA/BA FAM riders on each individual customer class rates -- rate impact.

BY MS. RUDDERHAM:

Q. Yeah, but can you do it like compared to what the rate asks are for this Application? I just want to look at it so you can actually compare.

A. (Willett) So a comparison to Figure 2-1?

Q. If you could, yes.

A. (Willett) Yes.

THE CHAIR: And was it just the FAM riders we were looking for?

BY MS. RUDDERHAM:

Q. DSM's not already embedded, is it? It's separate for 2026, or is it embedded?

A. (Willett) You're talking about in the GRA Application. So the DSM riders in front of the Board currently are not imbedded into the GRA. It is the 2025 riders that are in the GRA.

Q. Could we get that as well? And I

believe -- I take Mr. Williams' point about the securitization rider is -- there's too many variables at this point, but the DSM rider's known and the FAM AA/BA's at least ---

A. (Willet) Yes, we can incorporate the proposed 2026 DSM rider that's in front of the Board.

THE CHAIR: That will be Undertaking U-15.

UNDERTAKING U-15 - To provide an order of magnitude impact of the AA/BA FAM riders and DSM rider on each individual customer class rate impact as a comparison to Figure 2-1

MEMBER DEVEAU: Just a question -- I don't -- I'm just asking. Are you going to -- do you intend on lumping in the DSM and the AA/BA together or show them General Rate, AA/BA, DSM, and then a total sort of thing?

MR. WILLIAMS: We would separate them.

MEMBER DEVEAU: Yeah. Okay. Thank you.

MS. RUDDERHAM: Those are all my questions. Thank you.

THE CHAIR: Thank you.

Municipal Electric Utilities, Mr. MacDougall?

MR. MacDOUGALL: Yes, Mr. Chair. Not for the Munies, Mr. Chair.

THE CHAIR: Not for the Munies?

MR. MacDOUGALL: No.

THE CHAIR: Did you want to come up for PHP?

MR. MacDOUGALL: I do, Mr. Chair

(SHORT PAUSE)

CROSS-EXAMINATION BY MR. MacDOUGALL

Q. Good afternoon, gentlemen.

MR. MacDOUGALL: Mr. Goodine, could you pull up NSPI's direct evidence, N-3? And if we could go to page 13 of 99. That's the actual pages of the document, not the PDF.

BY MR. MacDOUGALL:

Q. And here, gentlemen, I'm looking at lines 16 to 20, and it says:

> This work with the Provincial Government has also resulted in the development of the securitization approach, related to key thermal assets, under section 35G of the *Public Utilities Act*. When put into effect, this approach could save customers as much as $90 million over 2026-2027 by removing these assets from NS Power's rate base and financing them through lower-cost debt.

Do you see that?

A. (Flemming) Yes.

Q. And when you filed your

Application, assuming that rates were in place and securitization was in place by January 1, 2026, your expectation was savings over the years 2026-2027 of approximately $90 million; correct?

A. (Flemming) Correct.

[4:10:09] **Q.** Thank you.

MR. MacDOUGALL: Mr. Goodine, are you able to pull up references from the transcript from yesterday? If not I can probably proceed without them. That’s okay. Let me try and proceed without them.

BY MR. MacDOUGALL:

Q. My notes, Mr. Williams, suggest that yesterday when you were asked by one of my friends a question on when you anticipated securitization could now be in place you anticipated that under current circumstances and the fact that Regulations are not yet in place that it would be sometime in the first half of 2026, and then you clarified that by saying close to the middle of the year. Do you recall that?

A. (Williams) I recall a discussion. I wasn't intending to clarify or change it. It was the first half of 2026.

Q. The first half.

A. (Williams) Middle of the year.

Q. No, that's fine.

So if securitization doesn't come in place till, let's just say, June 1, 2026 -- we'll just pick that time period, the first half of the year -- then just on a linear basis would that mean for the time period 2026-2027 the benefit of securitization would be cut in one quarter, $22.5 million less in securitization benefit?

MEMBER DEVEAU: Mr. MacDougall, I think you said June 1st. Did you mean July 1st?

MR. MacDOUGALL: Yes, Mr. Chair. Sorry. Right.

BY MR. MacDOUGALL:

Q. Six months. Halfway through the year. Thank you for the clarification. Appreciate that.

A. (Flemming) So, Mr. MacDougall, the proposal from Nova Scotia Power is to defer depreciation expense and financing costs within the 2026-2027 period and then securitize that amount. So to the extent that rates are in place before then, and the deferral is in place as well, Nova Scotia Power would expect that the bulk of that benefit to customers would still be passed onto customers. And the reason for that is because Nova Scotia Power would not have in its revenue requirement the depreciation expense or the financing costs. That would be built into the securitization issuance that is recovered to customers over a long period; 30 years is the expectation.

Q. Okay. I understand that it wouldn’t be built into the rates, but the benefit of the securitization itself would be reduced by some amount, would it not, not the benefit of the portion that is not already built into your rates, or would it not?

A. (Flemming) No. I believe that it

would not be. There would be potentially a little bit more of financing costs that would be deferred and recovered over time but should be very minimal in the overall impact to customers in terms of recovering that over a 30-year period. So we would still expect that -- we would still be in the same area of benefit to customers regardless of whether that happened January 1st versus July 1st.

Q. So your anticipation would be the value of the securitization for the time period, some portion of 2026 through to 2027, would still be a benefit to ratepayers in the amount of approximately $90 million?

A. (Flemming) We did update the $90 million through the IR process so we were closer to $85 million as our best expectation, and we would still expect to -- close to that benefit for customers over the test period as a result of securitization on a net basis.

Q. Okay, that's great. Thank you very much.

A. (Flemming) You're welcome, Mr. MacDougall.

MR. MacDOUGALL: If we could stay in N-3, Mr. Goodine, and if we could go to page 53, line 1.

THE CHAIR: Sorry. While we're pulling that up, just if you're moving to a new topic just one point I'd like some clarity on in terms of the -- that deferral, securitization deferral, if that's okay Mr. MacDougall.

MR. MacDOUGALL: No, absolutely, Mr. Chair. Go ahead.

THE CHAIR: Mr. Flemming, did I hear you correctly that the intent of Nova Scotia Power is if there is a deferral that would also be part of the securitization, so it wouldn't be the 704 million anymore, it would be 704 million plus whatever the deferral balance is?

MR. FLEMMING: That's consistent with Nova Scotia Power's proposal, is to defer any depreciation expense and financing costs associated with those assets. We've removed all of those costs from our revenue requirement for that period, and so Nova Scotia Power is proposing to defer that and recover that through securitization over a 30-year period.

THE CHAIR: Okay, thank you.

Sorry, Mr. MacDougall.

MR. MacDOUGALL: No problem, Mr. Chair.

MR. FLEMMING: One moment, if you don't mind, Mr. MacDougall?

BY MR. MacDOUGALL:

Q. No problem.

A. (Flemming) I just want to confirm.

Q. No problem.

A. (Flemming) Sorry, Mr. MacDougall. Ready to proceed.

Q. No problem. Just following up on

the Chair's question there. Your proposal, though, is to defer those costs from January 1, not from the date when new rates go in place; correct?

A. (Flemming) That's correct, Mr. MacDougall.

Q. Okay, thank you. If we could now look, then, at the reference on the page here, page 53 of your Application, starting in the first sentence. And here, you're giving options of what can happen with the deferral, and you say:

> Conversely, if it is determined that such a securitization will not be possible, NS Power will amend this filing to include the approximately [700 million] of DDA assets in its rate base over the GRA period and inclusion of the associated depreciation expense and [funding] costs in its applied-for revenue requirement.

Correct?

A. (Williams) Yes.

Q. That's what you had proposed to do in that circumstance.

A. (Williams) Correct.

Q. Okay, thank you. Now, if the assets proposed to be securitized were in rate base, you would not be receiving any further recovery in relation to them than what is already in rates until such time as new rates are set; correct?

A. (Williams) I think I followed that, Mr. MacDougall, but if you could just run it through one more time.

Q. Sure. If the 700 million that you're stating to be securitized, if that was just still in rate base you would not be receiving any further recovery in relation to those assets than what is already in your current rates until such time as new rates are set.

(SHORT PAUSE)

MR. FLEMMING: Mr. MacDougall, yes, I believe this is similar to the line of questioning that we went through with Ms. MacAdam yesterday in terms of the ---

BY MR. MacDOUGALL:

Q. Right.

A. (Flemming) Yeah. It is certainly acknowledged that under a normal process that when Nova Scotia Power has rates set, it is covering the costs associated with the rates that are in place. I think that there should be acknowledgement that this securitization process is novel, it's complex, it's the first that I'm aware of to this degree in Canada, and it is -- it's a centrepiece, really, of this General Rate Application and the reduction -- just one second, please.

(SHORT PAUSE)

MR. FLEMMING: Sorry about that, Mr. MacDougall.

So it's a centrepiece of the General Rate Application, and it's a significant cost savings for customers as well as significant foregone earnings for Nova Scotia Power. And I think because of that, it did take us a little bit longer to put it together, acknowledge that if we had submitted it earlier that rates could have been in place, but that's really the reason for the delay.

BY MR. MacDOUGALL:

Q. Okay, but just to get clarity there. You agree that if these assets were in rate base you wouldn't be saving further recovery in relation to them until new rates are set; correct?

A. (Flemming) Sorry, Mr. MacDougall; if the rates were not in rate base?

Q. If the assets were not in rate base.

A. (Flemming) If the -- excuse me. If the assets were not in rate base?

Q. No, they were in rate base. You are taking them out. If they were in rate base you would not be receiving any further recovery in relation to them than what's already in rates until such time as new rates are in place. I think you confirmed that, it's just you continued on. I just want to make sure that's my understanding.

A. (Williams) Yeah, I think we're just struggling with how you're asking that question, Mr. MacDougall, and it's probably our fault more than anything here. But -- so I think we're confirming that, but we're also not asking to earn anything more than what's -- what would be earned if they were in rate base.

Q. Well, you're asking to have the depreciation and financing costs deferred and recovered later. That's a different approach than what you're asking for for all of your other assets that are in rate base. Your generation assets, they're in rate base, they're treated a certain way. You've securitized -- or you're attempting to securitize the others. In the intervening time period, you're now asking that even before the new rates are put in place that you can collect, for a deferral account, depreciation and financing costs, and you would not, until new rates are in place with respect to the other assets, get such a collection. It's a different treatment for the exact same type of asset, and yet there's no securitization in place.

I understand why this would make sense following you getting new rates in place to put them into the same position, but prior to that, there -- you're now treating identical generation assets in a different manner. Correct?

A. (Williams) So maybe -- I'm going to sort of parse that. So when you say about you would agree with us where if rates were in place then that would be the treatment, and so that's, I think, a different -- that's not part of the discussion as I understand it, right? You ---

Q. Well, I ---

A. (Williams) --- you're only accepting that as a ---

Q. I'm at least saying to the company that if you had ---

A. (Williams) Yeah.

Q. --- put forward a proposal for deferral to cover the time period from when new rates go in place to when securitization went in place, there may not be a disagreement.

A. (Williams) Yeah, and I think the proposal would encompass that as well because if you get the deferral as of January 1, then you also have the deferral as of the period between when rates came in and when securitization ---

Q. If that had occurred, but yes.

A. (Williams) Yes.

Q. Yet you're still requesting the deferral for the depreciation financing from January 1, not from the date that rates are going to go in place.

A. (Williams) Yes.

Q. And to me, that is a different treatment than the treatment being accorded to the collection of costs in relation to generation assets not going into the deferral account.

A. (Williams) Yes.

Q. You can disagree with that if you wish, but that's -- I have stated to you that I believe that's the position that the company is asking ratepayers and the Board to approve.

A. (Williams) No, you're right, it's different treatment. But it's different treatment recognizing what we're trying to do here, which is the securitization. I think that's where Mr. Flemming was going with talking about the importance of the securitization, the novel nature of the securitization, the assumptions that were relied on about securitization when the Settlement Agreement was reached.

So I understand the questions about this. I do. It's really a function of the financial position the company is put in as a result of the delay in the securitization.

And Mr. Flemming can speak to that in

more detail, but I don't disagree with your -- the distinction you're drawing, in that we would be treating these differently. We would be. But there's a reason to do that, and the reason is, as I explained, because of the securitization, because of the assumptions that were made and the savings that would be obtained as a result of the securitization that are now not being realized because of that delay. And so what we're attempting to do is put the company into the position that it thought it would be as a result of the Settlement Agreement. And as we discussed yesterday, the securitization is -- it's a complicated endeavour. It's one that we have been pursuing. And when I say "we" I mean the collective we. It's one we were discussing in the last General Rate Application. It's something that we've put a tremendous amount of work and effort into progressing to the point where it is today. But at this point, it's not within the control of Nova Scotia Power to continue to push it over the line, it needs to come from elsewhere.

And so all we're looking to do is, yes, draw the distinction you've identified, but draw it for the reasons that I'm describing. And I'll maybe let Mr. Flemming get a word in here now and just describe the magnitude and the importance of it.

A. (Flemming) It's very significant. So if we look at, and I did touch on this yesterday as well, but in terms of a delayed decision, in terms of non-fuel rates, if we had a delayed decision until April 1, as well as no ability to defer the depreciation expense and the financing costs, it would, in effect, be equal to the amount that Nova Scotia Power is requesting in non-fuel revenue for the entirety of the year.

So a delay to April 1st, with not having the ability to defer, with not having the non-fuel rates, would in effect result in no new non-fuel rates for Nova Scotia Power during that period.

And I do take your point, Mr. MacDougall. I agree; Mr. Williams also agrees. The other option for this would be for us to have delayed the securitization, in terms of the forecast, and build those costs into Nova Scotia Power's revenue requirement, be conservative and say, "We're not going to be able to securitize for a longer period of time." We thought that the best case, in order to manage this and to promote affordability for customers was to recognize the securitization as of January 1 and pass those savings on to customers as part of the securitization package, and recover that over a longer period of time, recognizing that there is affordability concerns for our customers in Nova Scotia right now.

Q. Sure, but isn't this a bigger issue of the timing of when you're going to get rates in place, as opposed to the timing of the securitization? Because there's no mismatch if you get rates in place and you ask for the deferral of the financing costs and depreciation costs from that time period until when securitization comes in place. The mismatch here is that there’s a time period, that if you hadn’t proposed securitization and you had assets, you wouldn’t be entitled to recover any more, but you wouldn’t be entitled to recover any more as of January 1 because you didn’t get rates in place until January 1. Now you’re saying despite that, for a portion of the assets, and I believe $700 million is more of the assets than the assets that aren’t in the $700 million, from a generation perspective, you’re asking to have those costs deferred and recovered at a later time, yet you don’t get any recovery in the normal course from this Board if you otherwise just have them in rate base.

Do you disagree with that? I understand you have reasons why you think it’s correct, but it’s asking that you get recovery for assets differently than other generation assets that are similar simply because you proposed to securitize them, and then you didn’t have rates in place before the securitization period.

A. (Williams) As I said, Mr. MacDougall, I don't disagree with the distinction you're drawing. I understand it and I'm -- I don't think it's one I can or could disagree with.

Q. Okay.

A. (Williams) It is a real distinction that we're asking to be drawn.

Q. Okay. Thank you very much.

[4:30:00] I believe my colleague asked some questions on this yesterday, but I'll try not to spend too much time on it, but can NSPI give the Board and ratepayers any sense of what the hold up on the Regulation is, if this Regulation is worth upwards of $90 million to ratepayers? Have you been provided any sense of why it's...?

A. (Williams) I'm just trying to recall what I said about this yesterday, Mr. MacDougall, and I'm -- I don't have any new information between yesterday and today, but ---

Q. You didn't say very much.

A. (Williams) Yeah, but the reality is, like I believe I said yesterday, and I think as you're aware from discussions that we've had, and I mean here, that we have -- this is a concept that we know -- we knew years ago. And when I say years ago, I mean the last General Rate Application when we began discussions about this with the DDA and the DDA forming a basis for securitization, we knew had the potential to save customers money, and we have pursued that. Government took the initiative of putting section 35 -- I'm going to get it wrong now, 35(g), I believe it is?

Q. It is 35(g).

A. (Williams) Thirty-five (35(g)) of the *Public Utilities Act* in place. It's not enacted yet. It would need to be enacted, along with the Regulations. We have done the work to develop what those Regulations may look like. We have done the work with credit rating agencies to ensure that would be proposed would be satisfactory, from their perspective. We have likewise done that with the banks that would need to be involved.

So we have engaged and done everything that we, as a company, can do to bring this as close to fruition as we possibly can. And that said, the ultimate timing of this is not within our control, as we've discussed.

And I -- and I think what's most important in this discussion is what you and Mr. Flemming were just discussing, which is that there's still -- the benefit is still retained. So the timing of this, well, is not ideal, for many of the reasons that we've been discussing. From a customer perspective, the benefit is still something that we can retain, certainly the vast majority. I know the word "vast majority" -- the term "vast majority" has not been accepted in this proceeding thus far, but ---

Q. Understood.

A. (Williams) --- nearly all of the

benefit would still be retained for customers. So I give that as comfort, perhaps it’s cold comfort, but it should serve as some comfort that, you know, we continue to push this. We understand what it means for customers and we will continue to pursue it in any way we can, and we have no reason to think that it will not eventually come to fruition for the benefit of customers.

Q. Okay. Thank you for that, Mr. Williams.

A. (Williams) Thank you.

MR. MacDOUGALL: Mr. Goodine, earlier today Ms. Gillis sent you a one-page document. Would you be able to pull that up?

BY MR. MacDOUGALL:

Q. It’s just to follow up on your response to the last question, Mr. Williams.

MR. MacDOUGALL: And could you just make that a bit larger? Just focus -- yeah, that’s perfect.

<u>BY MR. MacDOUGALL:</u>

Q. So Mr. Williams, this is the proposed section 35(g) that you were referring to a moment ago?

A. (Williams) Correct.

Q. I can identify that this is an extract from the *Energy Reform (2024) Act*.

A. (Williams) I'm certainly happy to accept that.

Q. Thank you.

And I guess I want to start with a comment you made. You said that the section itself, not just the Regulations, has not yet been enacted. So is it -- I do notice that in the *Public Utilities Act* on the provincial websites there's no 35(g), but the *Energy Reform Act* says that Chapter 380, which is the *Public Utilities Act*, is further amended by adding this section. But your understanding is that this section isn't in force?

A. (Williams) I think we would need the full *Energy Reform Act* to understand at what point these sections are enacted. But I guess to get to the point of your question, yes, that's my understanding that it's not enacted, that it would need to be enacted to put any subsequent Regulations in effect as well.

Q. Okay. So it wasn't just the Regulations. You're still awaiting the enactment of this section; is that correct?

A. Yes, but we would expect it to be entailed.

MEMBER DEVEAU: Are you saying enactment or proclamation?

MR. WILLIAMS: Proclamation I thought would be the ---

MEMBER DEVEAU: Okay. Yeah.

MR. WILLIAMS: Thankfully we've got a lawyer's view on here.

MR. MacDOUGALL: The other two lawyers talking to each other didn't suffice.

(LAUGHTER)

BY MR. MacDOUGALL:

Q. That was my last question, Mr. Williams.

A. (Williams) A good note to end on.

Q. Yeah, it certainly was. Thank you, panel.

THE CHAIR: Mr. Boyle, do you have any questions?

MR. BOYLE: No, thank you, Mr. Chair.

THE CHAIR: Mr. Roscoe?

MR. ROSCOE: Yeah, I have a few; thank you.

THE CHAIR: Do you have a sense of how long you might be? Just trying to see if it's reasonable to finish your questions at least before 5:00 or thereabouts.

MR. ROSCOE: Yeah, it's -- I only have a few. I don't think it will take more than five or ten minutes.

THE CHAIR: Okay. Great.

CROSS-EXAMINATION BY MR. ROSCOE

Q. Thank you very much.

My comments once again are focused on fuel costs. Is it accurate to say that in each of the last five years, that's '21 to '25 inclusive, that Nova Scotia Power's actual cost of fuel have been higher than the base cost of fuel in each of those years?

A. (Willett) So I would say yes. But just to qualify that, the base cost of fuel has not always been set at the level of the forecast in all of those years. But I would say yes.

Q. That's a fair distinction. Thank you.

Have there been any changes to the methods or process used to create the BCF in this Application for '26 and for '27 that have been used in the past five years?

A. (Pecurica) Mr. Roscoe, we continue to follow the FAM Plan of Administration, and the development of forecast assumptions is clearly outlined in Appendix B of that Plan of Administration.

Q. Right. So there's been no change to the Plan of Administration with respect to the creation of the ---

A. (Pecurica) No, not to my knowledge.

Q. Okay. And in that case is it reasonable to expect a different result in the next two years than has been achieved in that last five years with respect to the forecast of those fuel costs?

A. (Pecurica) Mr. Roscoe, the Plan of Administration exists for a reason, to keep the assumptions consistent and fair in the forecast. Markets move somewhat unpredictably, so it is -- it would be speculative on my part to say that it's going to go one way or the other way. We'd be forecasting our fuel and purchase power costs and requirements based on the best assumptions we have at the time of the forecast, also following the Plan of Administration on how to develop those assumptions. Whether we will over-forecast or under-forecast it depends on how the market moves and how things develop.

Q. Okay. Is the expectation that there's an equal chance of the actual cost being over versus being under in that? Are you aiming for a P-50 if you will?

A. (Pecurica) That is -- that was the expectation, yes.

[4:40:00] **Q.** Okay. And then the BCF for the test years are going up, but also there's change in the total amount of energy, there's changes above the line and below the line. On a per-unit basis the actual forecast of BCF per unit is actually coming down for '26 versus '25, the cost per megawatt hour if you will?

A. (Pecurica) Mr. Flemming is going to address that, Mr. Roscoe.

Q. Thank you.

A. (Flemming) Confirmed, Mr. Roscoe.

Q. Okay. Thank you.

Just one last question, and it's just following up on something Mr. Williams said about the allocation of a potential AA/BA and that it would be I guess potentially different by rate class and that industrial rate classes might pay more. Was that in a percentage basis or in a per-megawatt hour basis? Like, you know, the unit -- their energy costs -- their posted energy costs are lower. So I just wondered if that was per energy or per percentage.

A. (Willett) We were discussing on a percentage basis.

Q. On a percentage basis. So because their energy rates are lower and that would be a change in those rates; bundled versus unbundled, so to speak?

A. (Willett) Well, what I would say is just when you look at the fuel responsibility, so that's what the AA/BA process does, it's looking at how energy was actually consumed and assigning those costs to the various customer classes. So there is a higher percentage amount outstanding for certain classes. So even though the large industrial class is a smaller class, an outstanding balance can have a bigger impact on a percentage basis than other classes.

Q. Okay. That's helpful for my understanding.

MR. ROSCOE: No further questions.

THE CHAIR: Thank you.

Is there anyone that I've overlooked, other than Board counsel?

Okay. Mr. Mahody, I think, given the time of day, it probably makes sense to break here and resume in the morning.

MR. MAHODY: I certainly think I'll be some time with the panels.

THE CHAIR: Okay. So we'll adjourn

for the day and we’ll resume at 9 o’clock tomorrow morning.

Just a reminder -- I think I’ve been forgetting to do this, but you remain under oath so you can’t talk to anyone about your evidence at this point, except amongst yourselves.

--- Upon adjourning at 4:42 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, M12451.

____
Patricia Cantle
Registration No. 2017-001
ICDR, ICDT
Certificate No. IAPRT-2142

Halifax, Nova Scotia
Thursday, January 8, 2026