M12661

NOVA SCOTIA ENERGY BOARD

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

- and -

IN THE MATTER OF: **AN APPLICATION by NOVA SCOTIA POWER INCORPORATED** for approval of an Extra Large Industrial Dispatchable Above-the-Line Tariff applicable to Port Hawkesbury Paper

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TRANSCRIPT

HEARD BEFORE: Mr. Stephen T. McGrath, K.C. Chair
Mr. Richard J. Melanson, LLB, Member

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

DATE HEARD: Tuesday, September 29, 2026

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September 29, 2026

Halifax, Nova Scotia

--- Upon commencing September 29, 2026 at 10:00 a.m.

THE CHAIR: Good morning, everyone. Any preliminary issues before we begin this morning?

Okay. Mr. McLaren, I see you online. Can you hear me okay? And we can do a bit of a sound check before we get going.

MR. McLAREN: Yeah, I can hear you just fine.

ANDREW McLAREN, Resumed

HAYITBOY MAHMUDOV, Resumed

(SHORT PAUSE)

THE CHAIR: I think we're good to go now. Mr. MacDougall, whenever you're ready.

MR. MacDOUGALL: Thank you, Mr. Chair.

CROSS-EXAMINATION BY MR. MacDOUGALL

Q. Good morning, gentlemen. I'll just ask the questions, and you guys can decide which one of you is going to respond.

Last week, did you listen into the hearing and hear Nova Scotia Power's testimony?

A. (McLaren) Yes.

Q. Okay. And did you hear when they confirmed that they utilize a system load factor methodology to split generating resource costs between demand and energy?

A. (McLaren) Yes.

Q. Okay. So accordingly, a portion of fixed generation capacity costs are actually recovered through the ELID non-fuel portion of the energy charge rather than the demand charge?

A. (Mahmudov) We understand that energy rates include a portion of fixed charges -- or fixed costs, sorry.

Q. Okay. Thank you.

Is it, in your view, reasonable to develop rates for a distinct customer class by using the billing determinants of an entirely different class?

A. (Mahmudov) No, it is not, I think.

Q. Thank you.

And do you understand that Nova Scotia Power utilizes a winter 3CP method for the allocation of demand costs?

A. (Mahmudov) Yes.

Q. And we have evidence on the record of PHP's recent historical peaks for 2024 and 2025?

A. (Mahmudov) Yes.

Q. And Nova Scotia Power has estimated that the demand response value could be somewhere in the range of $7 to $11 million if fully optimized, but it expects that the amount that can be realized is approximately half that amount, 3.5 to 5.5 million; correct?

A. (Mahmudov) Yes, we saw those numbers.

Q. Okay. So in NSPI's view, the DR value could be as low as $3.5 million.

A. (Mahmudov) Against theoretical customer baseline, yes.

Q. And the potential 7 million to 11 million value is only an estimate based on analysis completed in 2025 utilizing forecast data?

A. (Mahmudov) I don't recall the exact details, but that -- I think that's right.

Q. And at the beginning of 2027, PHP will not know what the ultimate DR value will be; correct?

A. (Mahmudov) That's our understanding. That's my understanding.

Q. And you also propose some aspect of benefit sharing? And I think yesterday you made a comment that you think that should possibly be in the range of 20 to 30 percent. Is that correct?

A. (Mahmudov) That was the number that we can see or revenue amount that we can see being generated at the moment under the ELIADC for fixed cost contribution from PHP so that that makes about 20 to 30

percent, I think, of the DR savings as estimated today by NSP. So yeah, on that basis. Yes.

Q. Okay. And if there was to be some aspects of benefit sharing, this would reduce the benefit of load shifting to PHP that is attributable to the dispatchable rider. PHP would get less of the benefit.

A. (Mahmudov) I would say as proposed under ELID, but not as under the current tariff of ELIADC.

Q. No, but if there was some benefit sharing to be under the ELID, that would reduce the amount of benefit that would be attributable to Port Hawkesbury Paper.

A. (Mahmudov) Versus what's proposed yes, because what's proposed is 100 percent.

Q. Right.

A. (Mahmudov) So yes.

Q. Yeah. So the 3.5 million, that could be even lower from PHP's perspective if there was benefit sharing.

A. (Mahmudov) Yeah. And if those numbers turn out to be the case, then yes.

Q. Correct.

And do you understand that PHP incurs operational and commercial costs with respect to being available as a DR customer?

A. (Mahmudov) I think it was discussed in this testimony, in this hearing as well. That's what we heard.

Q. Yeah. So your understanding is that PHP's evidence is that it incurs operational and commercial costs to be a DR customer.

A. (Mahmudov) Yes. That's what PHP has stated, so based on that -- on those statements, yes.

MR. MacDOUGALL: And if we could -- Mr. Norwood, if we could bring up Exhibit N-1, the NSPI Application.

And if we can go to Attachment 1 in N-1. Attachment 1 is the DR mechanism.

And if we could go just to the top of that, Mr. Norwood.

BY MR. MacDOUGALL:

Q. So from the tariff proposed by NSP, you'll see here that the DR mechanism has been proposed as a rider to the ELID tariff; correct?

A. (Mahmudov) Correct.

Q. Now, if we can go to the IT credit proposed for PHP by NSPI in the same attachment.

MR. MacDOUGALL: It's page 5 of 7 in the interruptible credit rider.

There we go. Thank you, Mr. Norwood.

BY MR. MacDOUGALL:

Q. And for -- for 2027, Nova Scotia Power is proposing an IT credit of $7 -- 7.667 per month per kV, a reduction in the demand charge for billed interruptible demand; correct?

A. (Mahmudov) Yes.

Q. Okay. And do you agree that the

basis for why they're putting that number forward is based on their interpretation of the language in the settlement agreement, that the interruptible demand is to reflect the value of the large industrial interruptible rider interruptible demand?

A. (Mahmudov) I believe, yeah, that is consistent with the settlement agreement language. Yes.

Q. But Nova Scotia Power has also stated in its Application and throughout this proceeding that if the Interruptible credit was developed for PHP using NSPI's established practice for pricing of the IT credit, it would be $13.10; correct?

A. (Mahmudov) Yes. That's what NSPI is saying.

Q. Okay. Gentlemen, I'm going to spend a little time going through some figures and math, and particularly because we're doing this virtually, I'll try to go slow, but if you need me to go backwards or take a moment, please do that.

MR. MacDOUGALL: Mr. Norwood, could we pull up NSPI's Responses to the Interruptible Groups IRs. That's Exhibit N-6.

And if we could go to the question for Interruptible Group IR-7, I believe it's PDF page 220. But it's IR-7 that we're looking for.

No, sorry, that's the numbers I'm going to come to shortly. If we could just go to the question for IR-7. I don't have the specific page reference. It will be much earlier in the document.

UNIDENTIFIED SPEAKER: Sorry to interject. Could I just ask Mr. Norwood to show the PDF page?

MR. MacDOUGALL: Just page 12, Mr. Norwood. Yeah, there we go.

UNIDENTIFIED SPEAKER: Thank you.

BY MR. MacDOUGALL:

Q. So gentlemen, I'm going to go through some of the numbers in the attachments to this IR.

But just to start out so that we can be on the same page, the first attachment that I'm going to look at is the response to IG IR-7(a)(i). And I'm just going to read that out for the record.

That attachment is meant to be:

> Using a PHP firm load of 8 megawatts for 3 CP and 57 megawatts of interruptible load, as proposed by NSPI, priced at the NSPI proposed credit rate ([of] $7.661 per kVA...

You see that?

A. (Mahmudov) Yes.

Q. So I'll be referring to that attachment as using the LIIR credit figure of 7.661.

And then the next attachment I'll be referring to is the response to IG IR-7(a)(ii):

> Using a PHP firm load of 8 megawatts for 3 CP and 57 MW of interruptible load priced at the PHP proposed rate...

Using the $13.107.

Do you see that?

A. (Mahmudov) Yes.

Q. Okay. So the difference between

the two is simply the difference in the interruptible rider credit; correct?

A. (Mahmudov) Yes.

MR. MacDOUGALL: And now, Mr. Norwood, If you could go to PDF page 220.

In fact, Mr. Norwood, what I'd rather do than that is if you could pull up the exhibit that Mr. MacDuff sent to you yesterday, which is -- it starts on the first page, IG IR-7, Attachment 3.

BY MR. MacDOUGALL:

Q. And gentlemen, to try to make this easier, what I've done is just created a package of the pages from the responses to those two questions. This is all in the record, but I thought if we used a single document, it'll make it a lot easier for Mr. Norwood to -- to move through the various pages. So as I do this, I will indicate for the record which -- which page number it is in the responses to the IR-7 PDF.

So the first document we have here is a

revenue to expense comparison. It's Exhibit N-6 PDF page 220, and it says Attachment 3. And Attachment 3 is the response to the first question using the 7667.

You follow me so far?

A. (Mahmudov) Yes.

Q. Okay. And this shows in line eight under column 1 total demand related expenses of $12,009,000; correct?

A. (Mahmudov) Correct.

MR. MacDOUGALL: Okay. And then if we go to the next page, Mr. Norwood.

BY MR. MacDOUGALL:

Q. And this is PDF page 410.

And you'll see here the references to Attachment 5, and Attachment 5 is the response to the second question where NSPI's data was using the 13.107.

And here if we go to the revenue comparison, you'll see for the ELI two-part RTP, the revenue is only $7,785,000.

A. (Mahmudov) Not the revenue allocated cost.

Q. The demand related expenses; correct?

Thank you for the clarification.

So if you could take it subject to check that the 12,009,000 minus the 7,785,000, the difference is $4.2 million?

A. (Mahmudov) Subject to check.

Q. And had --

A. (Mahmudov) Yes.

Q. And had you heard last week that that was the figure, the $4.2 million was referred to in various cross-examination of Nova Scotia Power as being the difference between utilizing the $13 credit versus the 7.67 credit of what the credit would be to Port Hawkesbury Paper.

A. (Mahmudov) Yes.

Q. Now, if we go to the next page.

And this is found at PDF page 168, and it's allocation of operating expenses. And again now we're back to Attachment 3.

So this is just utilizing the 7.667. Every reference to Attachment 3 is the 7.667 and every reference to Attachment 5 is using the 13.107.

So here if we look at line 28, we see that the interruptible rider for the -- and column 1, the value of the interruptible rider for demand adjustment is a negative $11,207,000; correct?

A. (Mahmudov) Yes.

Q. And that's the full value of the of that class's IT credit. That's how much money is to be returned to the large industrial Interruptible rider customers.

A. (Mahmudov) Yeah. I cannot see the heading, but I think, yeah, I agree with you.

Q. Well, it says total company and then it goes down line 28.

MR. MacDOUGALL: If we could go up -- if we could go up a bit. Mr. Norwood so Mr. Mahmudov can see total.

BY MR. MacDOUGALL:

Q. So it's under total company across from line 28, interruptible rider demand adjustment minus $11,207,000.

A. (Mahmudov) Okay. Yes.

Q. Okay. And so that's the -- that's the amount of credit in millions of dollars that the large industrial interruptible class would receive.

A. (Mahmudov) Yeah.

Q. Okay. And this is under -- just under the generation function; correct?

A. (Mahmudov) Yes.

Q. Okay. And then if we go to line -- excuse me. If we go to line 30. And again, we're under Attachment 3 using the LIIR figure for the interruptible credit, you'll see the ELI two-part RTP demand adjustment

is $5,579,000; correct?

A. (Mahmudov) Yes.

Q. And is it your understanding that the reference to the old ELI two-part RTP is actually a reference now to the ELID proposed tariff? That's the say that's PHP.

A. (Mahmudov) Correct, yes.

Q. So using this interruptible credit, the amount of total dollars that would be payable to Port Hawkesbury Paper would be $5,579,000, correct, for interruption alone.

A. (Mahmudov) Correct. Yeah. That's an offset to offset to --

Q. An offset. It's not a payment, but an offset; correct?

And then if we look down a couple of further lines, we see at line 32, $558,000. And that's on account of the 10 percent priority interruptible; correct?

A. (Mahmudov) Correct.

Q. Okay. Now, if we go to the next page, which is, for the record, PDF page 359, now we're again at Attachment 5 using the $13 credit.

MR. MacDOUGALL: So if we go to the same line and column -- maybe we could make this a little bigger, Mr. Norwood. There we go.

BY MR. MacDOUGALL:

Q. And we see for the LIIR, the interruptible credit, the number is the same of 11,000,207 because the only change here was the credit for Port Hawkesbury Paper; correct?

A. (Mahmudov) Correct.

Q. Okay. But now if we look at the ELI two-part RTP, i.e. PHP, the interruptible credit would be $9,537,000; correct?

A. (Mahmudov) Correct.

Q. And if we look down at line 32, it says the priority interruptible would be $954,000; correct?

A. (Mahmudov) Correct. Yes.

Q. Again, roughly 10 percent of the of the interruptible credit.

A. (Mahmudov) Yes.

Q. Now, if I can -- just before I continue through the documents, if I could just stop here for a moment.

So NSPI's response to IG IR-7 showed $954,000, but we heard last week that NSPI's proposal now is that if Port Hawkesbury Paper was given the $13 credit, NSPI's proposal is now not to give a priority interruptible credit of $964,000 despite having shown it in the IR response, but to only give a credit in the range of roughly $500,000 -- or $550,000 being 10 percent of the LIIR.

Did you understand that from the discussion last week?

A. (Mahmudov) Yes.

Q. Okay. Thank you.

MR. MacDOUGALL: So now if we can go to the next couple of pages.

Next page. Sorry.

And here, Mr. Norwood, if we could start by showing -- trying to get everything on the one page showing there.

BY MR. MacDOUGALL:

Q. And here what we've done is just because -- we'll broaden this, but just to start because the -- the amount of information on the pages was small, we put both Attachment 3 and Attachment 5 on the one page. Attachment 3 is PDF page 174, and Attachment 5 is PDF page 364.

Do you see that?

A. (Mahmudov) Yes.

Q. Okay. So again, up at the top we're dealing with the LIIR. And at the bottom, we're dealing with Port Hawkesbury Paper.

A. (Mahmudov) Okay.

Q. The 1307. Okay.

MR. MacDOUGALL: Now, if we could just

make the top part a little bigger, Mr. Norwood.

Maybe a tiny bit bigger than that.

There we go.

And if we see at line 4 -- actually, you have to shrink it up.

Perfect. That's great.

BY MR. MacDOUGALL:

Q. If we see at line 4, the --there's the -- for the use -- for the attachment using the LIIR, we see the interruptible credit amount is just as we discussed previously, $11,207,000; correct?

A. (Mahmudov) Yes.

Q. And you see that that's in relation to a demand in kilowatts of 69,857 kW; correct?

A. (Mahmudov) That I cannot confirm. I see that there's a demand number of 69,857 but, you know, without the model itself I cannot confirm if that's the basis for 11,207 number.

Q. Okay. Well, let's -- I'm going to

go to the next point. Maybe it will it will help sort it out for you.

So this is NSPI's response for the allocation of operating expenses for the year ending December 31, 2027; correct?

A. (Mahmudov) Yes.

Q. And they state the demand in kilowatts as 69,857; correct?

A. (Mahmudov) Yes.

Q. Okay. If we take the -- excuse me. If we take the 11,000,607 and divide it by 69,857, we come up with a figure of $160.40, which is exactly the cost of the peaker that NSPI uses for determining the interruptible credit. Can you take that subject to check?

A. (Mahmudov) Yes.

Q. Okay. And were you aware that the cost of the peaker NSPI was using was $160.40?

A. (Mahmudov) Yes.

Q. Okay. So if -- if the cost of the

peaker is $160.04 (sic), then it would make sense that the kilowatt number would be what is here because if you divide that kilowatt number into 11,207,000, you get exactly the cost of the NSPI peaker subject to check.

A. (Mahmudov) Okay.

MR. MacDOUGALL: Okay. If we can now bring up, Mr. Norwood -- we're going to come back to this page. But if we could look at Exhibit N-6, PDF page 225.

No. I'm sorry, Mr. Norwood. I'd like to go to N-1, page 8. And if we could go at page 8, footnote 5.

BY MR. MacDOUGALL:

Q. Here we see down in the bottom that for the $13.107, NPI says it uses the following formula winter coincident peak of ELID of 59,446 kW. Correct?

A. (Mahmudov) Yes.

Q. Okay.

MR. MacDOUGALL: So if we could go

back, Mr. Norwood, now to where we were.

No. If we could go back to the -- to the attachment we were on previously, the one that had both Attachment 3 and Attachment 5 on the same page just from the -- yeah. That's it.

Now, if we can go to the bottom, the bottom half of that.

If we could actually go over to the -- to the next page first, Mr. Norwood, which is a detailed listing of cost of service input information. And if we could go down to line 73.

And then if we can make that a little bigger.

BY MR. MacDOUGALL:

Q. And here, Mr. Mahmudov, you can see again this is using the LIIR figure for the interruptible coincident demand at the generator. There's the same 69,857 number that we used for the Nova Scotia -- for the calculation we did previously; correct?

A. (Mahmudov) Correct.

Q. Okay. And now you see below that PHP interruptible coincident demand at the generator of 59,456, which is the number that we just showed as the amount of kilowatt demand in the footnote 5 in N-1; correct?

A. (Mahmudov) Correct.

Q. And if we can go to the next page attachment --

THE CHAIR: Just before we do, just the PDF page for this one?

MR. MacDOUGALL: Sorry, Mr. Chair. PDF page 225.

THE CHAIR: Thank you.

MR. MacDOUGALL: And then if we can go to the next page. Now we're on -- if we can go to the top of that, it's PDF page 415.

BY MR. MacDOUGALL:

Q. It's now Attachment 5 again using

the $13. But when we go down to line 73, you can again see it's the exact same numbers that are being used by NSPI for the kilowatt demand for both the Interruptible customer and for Port Hawkesbury Paper; correct?

A. (Mahmudov) Correct.

Q. So all these numbers we've gone through, they're all consistent through all the documents; correct? Through all the documents I brought you to.

A. (Mahmudov) Yeah, correct.

Q. Okay.

MR. MacDOUGALL: So now if we could go back to the PDF page 174, the -- two slides back, Mr. Norwood.

And now if we can go -- we're under Attachment 5. So if we can go down below.

Yeah, we can stop there. So now we're on -- this is Attachment 5.

If you scroll over to the righthand side just to show that, Mr. Norwood. Here we are.

Attachment 5. So then you can go back to where we were.

BY MR. MacDOUGALL:

Q. So again, now we're under the $13 so we're in Attachment 5.

And you can see using the $13 we see at line 11 under base amount the same amount we previously talked about if you use the $13 credit for Port Hawkesbury of $9,537,000; correct?

A. (Mahmudov) Correct.

Q. Okay. And if you take it subject to check that if you multiply the Port Hawkesbury Paper demand of 59,446 kilowatts demand times 164.4 for the peaker cost, you would get exactly $9,537,000.

A. (Mahmudov) Say it again, please.

Q. If you take the amount of kilowatts of demand that NSPI is showing for PHP comparable to the Interruptible class, the number's 59,446. And if you multiply that by NSPI's cost of a peaker of $160.44, you will get $9,537,000.

A. (Mahmudov) Subject to check, yes.

Q. Okay. So using the 13.07 as the credit will ensure that PHP receives the same value per kilowatt for the avoided cost of the peaker as the large industrial interruptible rider; correct?

A. (Mahmudov) I think that is already the case in terms of the base for that calculation of the credit, whether it's for PHP or for a large industrial. So the $160.44 is already there. And I think the difference being -- is being driven here by the ratio of coincident peak to the build demand or non-coincident peak ---

Q. Can we stop there for a second?

The -- the ratio of build, that's for setting the rate. I don't -- we don't have to talk about setting the rate. Port Hawkesbury Paper in this case, the rate -- the rate is going to be the same as the billing demand. Now, that's what's proposed.

We're not talking about the rate here. We're talking about the absolute dollars that the class is

going to collect. So if the class is -- the only way the class is going to collect $9,537,000 is if they get $160.44 for their total kilowatt of demand; correct?

A. (Mahmudov) In terms of dollars, yes.

Q. Yes, in terms of dollars.

So otherwise, they only get the full cost of the peaker if they're given a interruptible credit that allows them to get a credit for $9,537,000.

A. (Mahmudov) Sorry. Can you repeat that, please?

Q. Sure.

The only way that they're going to get the $9,537,000 is if they are actually paid a credit of $160.44 on their billing demand of $59,446.

A. (Mahmudov) Well, yes, that's assuming the -- the cost of a peaker is -- is being applied correctly, basically.

Q. Correct. Assuming the cost of the

peaker is being applied in the same manner as for the large industrial class. The same amount, the same value, $160.44.

A. (Mahmudov) I agree it's the same value, but I don't think it's the same manner.

Q. For the cost of service.

So what -- what did we just go through that -- that wasn't the same between Attachment5 and Attachment 3?

A. (Mahmudov) The difference is that NSPI's calculation for large industrial customers is not using the same method as being -- in my understanding, the same method as being proposed for PHP in that footnote. For large industrial customer, it's taking the coincident peak and dividing it by the build demand non-consistent peak for large industrial large industrial customers to determine the savings in relation to the cost of a peaker.

When it comes to PHP, the method says that we'll assume that the coincident peak and build demand

are the same. So it's not the same method.

So for PHP fixed cost or fixed charge revenue is already predetermined. NSP is saying it will be based on 65,000 kVA, whereas for ---

Q. Yeah, but ---

A. (Mahmudov) -- industrial it's not.

Q. But Mr. Mahmudov, that's the method of calculating for billing purposes. So under the large industrial interruptible rate because their non-coincident peak is larger than their coincident peak, if they got the credit for all of their large coincident -- non-coincident peak, they would over-collect the money. They would collect more than the $11,207,000. It's the amount of dollars they're allowed to collect. So therefore, they have to make an adjustment to do that.

In this case, though, at the end of the day, they will collect $11,207,000, and that is based on a peaker cost applied to their kilowatt demand. T hat's just what we went through.

In order for NSPI to get the full value of a peaker on their kilowatt demand, they have to be entitled to $9,537,000, regardless of how it is then collected from them.

That's what the cost of service is. That comes before setting bills. The rate design and the billing mechanism comes later. You have to look at the cost of service to -- to see this. Otherwise, they're not getting 160.44. They're just getting some lower number for no reason.

Tell me what I went through that that doesn't show the total value of the credit, not how it's collected, but the total value. These attachments show that the total value of the large industrial rate that they're entitled to is $11,200,000 because they're entitled to $160.44 per kW.

So if PHP is entitled to $160.44 per kW, then they're entitled to get $9,537,000. Is there anywhere in these documents that suggest otherwise?

A. (Mahmudov) 160.44 is the cost of a peak grand standard. It's based on the avoided costs on a marginal basis. This is the embedded cost of service and the rate, it just -- you know, if it's $9.5 million, it's being applied as a credit to PHP. Then when you compare it to the allocated costs, I think it will show that it exceeds the allocated costs, you know, generation related fixed costs to PHP for this amount.

Q. Okay. I'll leave it there, Mr. Mahmudov.

But there's -- did you follow the calculations we just went through?

A. (Mahmudov) I saw the calculations. I saw the output, sorry.

Q. Yeah.

A. (Mahmudov) Yes, I was able to follow the outputs, but obviously, I didn't go through the Excel model step by step to be able to confirm.

Q. Okay. We'll just do one -- one

more piece of math here just for the record.

MR. MacDOUGALL: If we go now to the top part of -- of this exhibit, Mr. Norwood, again, it's back to page 174.

And if we could make it a little smaller. And here again, if we go -- you could make it a little bigger just so we can see the shaded figures.

Tiny bit more. That's great.

BY MR. MacDOUGALL:

Q. So here, if we go to line 11, you see the sum of monthly demands in kVAs as you go across here. And you'll see again because we're in Attachment 3, it's using $7.667. And that yields an amount of only 5,579,000, which we showed before; correct?

A. (Mahmudov) Yes.

Q. Okay. So again, if you could take it subject to check that, if you divided 5,578,948 by the cost of a peaker, $160.44, you would only get 34,772 kW.

Could you take that subject to check?

A. (Mahmudov) Yes, subject to check.

Q. So if that was the case, Port Hawkesbury Paper would only be credited for roughly 35,000 kW of avoided capacity even though they are being told that there's 57,000 megawatts of avoided capacity -- or, in fact, with the -- with the load losses or transmission losses, the 59,000 figure.

So if that was the number and they're entitled to the avoided cost of a peaker, they would only be getting the avoided cost of a peaker for roughly half of what they're avoiding.

A. (Mahmudov) I believe that Nova Scotia Power themselves noted that the credit -- in terms of credit, I think they mentioned that it was exceeding or coming very close to -- to offset basically the allocated cost for interruptible customers and I think PHP must --

Q. For large industrial interruptible customers. Not for PHP. That's what this shows. I just did the math again.

A. (Mahmudov) But by the same logic, that means that I guess if the same number is applied to PHP, then that will -- then PHP would also become to the same concern.

Q. No, if PHP is given the appropriate credit for PHP of $13.107, then they will recover 9 million -- the $9 million figure and that would be appropriate. If they're not given that, if they're given half of that, then essentially they're only being credited for 34,772 kW, although they're providing 59,446 kW of capacity avoidance.

A. (Mahmudov) Yes. But that value that we're talking about $13.107 figure per kVA, I think that's the concern of NSP as well that the calculated value of -- of that credit simply being, you know, equal, basically, to the cost allocated to those customers. So if we're using the same $13 and say that it should apply to PHP, I think it will have -- it will raise the same concern.

Q. I didn't hear any concern by Nova Scotia Power with the $13.107. They, in fact, showed on the footnote we just showed what the appropriate cost using their regular practice would be for Port Hawkesbury Paper. They simply said their view is that the settlement agreement number should be used of 7.667. They've never said it's cost based. In fact, they said the cost based figure would be $13.107.

And if you follow through these documents, you can actually see that that is the cost base because it is the only figure that will allow Port Hawkesbury Paper to recover the appropriate amount of interruptible credit when it's applied to the cost of a peaker that has been set for the large industrial rate at $160.44.

I had heard no -- no issue that Nova Scotia Power had with the with the $13 figure.

Did you recall them indicating an issue with it? I thought they indicated that it was the

appropriate rate if applied using the general practice.

A. (Mahmudov) Yes. Maybe if you allow me to call up Nova Scotia Power's rebuttal, it's Exhibit N-38. Maybe I can take you there.

It's PDF page 15 of the NSP's rebuttal evidence. And it's, I think -- yeah, right here basically lines 1 to 11. And in particular where it says in line 8:

> Effectively, demand costs assigned to these groups of customers are now largely being offset by the value of the interruptible credit these customers are receiving. This issue is recognized in the evidence which provides it's clearly unreasonable to determine that the value of an interrupted credit is higher than the full cost based demand cost for the firm service.

Q. No, that's -- that's referring, though, to a totally different point. That's referring to -- to your point where you had said in your evidence that if the -- if the amount of the credit exceeded the demand cost, that would be unreasonable. But as we've already indicated and that you gentlemen agreed to earlier, not all

of the demand cost is in the demand charge. Nova Scotia Power has a very unique cost of service where a substantial portion of demand costs are in the energy bucket. So you can have a demand credit that exceeds the demand cost X, the demand cost that's built into the energy bucket. And that's why it can exceed that.

Not all of the demand cost is in the demand bucket in the Nova Scotia Power cost of service, is it?

You agreed earlier it was not.

A. (Mahmudov) I agreed with that part, but I would also note that demand cost in the cost of service would not be limited to generation only. There is demand cost related to transmission, right. So -- and in the cost of service, I was not able to see a breakdown of how much of the transmission -- transmission fixed costs are being recovered through energy charge versus fixed charge. And I know that the -- as per the explanation that -- that we heard and as you referenced it, yes, you know, a

portion of the demand cost is recovered through energy charge. That's also practice of other utilities. But that rate for the demand charge, the $12 and $14 numbers that we saw, that -- that is supposed to reflect the allocated cost of demand and transmission at minimum.

And here we see a number of $13.107 as a credit just for generation only -- generation -- for the demand related to generation only. And that already exceeds this.

Q. Yes. But then we pay demand costs in the energy rate that then brings that number up so it isn't exceeded.

A. (Mahmudov) Well, yeah.

Q. There's no -- the credit formula --

A. (Mahmudov) If ---

Q. --- is the credit formula.

Again, I'd just take you back to the -- the map we just went through.

MR. ROBERTS: Could the witness be given an opportunity to respond? I think he's been interrupted two or three times now. He's trying to respond.

MR. MacDOUGALL: My apologies, Mr. Chair.

MR. MAHMUDOV: Thank you.

So the energy charge includes portions of fixed costs. Those fixed costs are not generation only. They include transmission and they include any other, you know, just common costs and stuff which are also fixed.

So when you see an energy credit applied, which is supposed to be generation only, and that's already higher than the demand rate which captures, you know, not only generation, but also other functions of NS Power, that already raises a concern because in the cost of service or in the rate design, I do not recall seeing a figure or a table or anything like that which says, you know, this percent of the demand related -- generation

related demand cost is being recovered by energy and this percent of transmission demand related costs are being recovered by energy. That's the first concern.

And second concern is -- in particular with respect to PHP is this offset of its energy by Goose Harbour. So we're really talking about this scenario which -- which is an extreme. But you know, what if the net energy being purchased by PHP is zero?

So under this scenario where the $13.107 per kVA is higher than the demand charge, I think that just brings the situation where PHP does not contribute anything to towards the system costs, but instead gets paid by the -- the utility and, in other words, by other customers to be an ACL customer. So that's just, you know, not really working out in terms of the math here as well.

So we just do not have that number, that -- that proof that, you know, it's this portion of the costs are being recovered by energy, and it's not at the

expense of other customers.

Q. But -- but Mr. Mahmudov, I wasn't talking about the Energy Credit ADC. I was talking about the interruptible demand credit.

A. (Mahmudov) Correct. And that's what I'm talking as well. So interruptible demand credit here as proposed in -- in that footnote, and it was proposed for future GRA, not for this GRA, but as proposed in the footnote, generates a number of $13.107 per kVA for PHP with 10 percent premium on top of it. That's higher than the demand charge for PHP in 2026 and in 2027, which is $12 something and $14 something per kVA.

Q. And that --

A. (Mahmudov) So -- and it's fixed, right. But we will explain that it's -- it's annualized fixed so it will be just a total dollar amount divided by 12.

So it's not even dependent on -- on PHP's actual, you know, CPU and actual NSP, actually non-

constant peak. It's just divided and collected like that.

So if you now apply to this in sort of credit, which is higher than demand charge, obviously then there is a negative amount being received from demand. And then you can, you know, analyze, okay, but we're recovering it through energy. But if your energy is also offset by Goose Harbour, then I don't think PHP will be -- or NSP can be recovering all of its costs -- allocated costs from PHP, which means that there is a risk that other ACL customers will be bearing that cost.

Q. You heard the evidence of Port Hawkesbury Paper that they didn't think there was any situation where there would be no energy, that their evidence is that there's going to be a considerable amount of energy still taken from Nova Scotia Power, regardless of the amount of megawatts that come from Goose Harbour.

A. (Mahmudov) I heard that, yes, but I think I also heard that there is already, you know, the adjustments are being proposed which reduced the net energy

versus what was in the settlement agreement. So any reduction in the net energy, basically, in this analogy means that less of fixed costs will be recovered from PHP because portion of the energy rates include fixed costs.

Q. Yeah. But if they take power from Nova Scotia Power and it's billed at -- the same way as it's costed, they will be getting the correct cost per megawatt hour or kilowatt hour of the energy that they're purchasing; correct?

A. (Mahmudov) If it matches the cost of service assumptions like the ability to forecast. We know that for the fixed portion it will match because they're saying that they assume that whatever is built in into the cost service for demand, the kVAs, is also -- will also be used for billing. So they say, you know, it's fixed. We'll just divide it by, you know, 12 and collect it monthly.

They're not able to do the same for the energy, so if the energy is lower, net energy is lower

than what's built into the cost of service and what's reflected in the rate design of NSP, then NSP cannot recover not only its, you know, admin and other charges so basically any other costs other than fuel costs in sufficient amounts to recover its costs from PHP, including the fixed cost, like demand related costs and whatnot, which were built into the energy rate.

Q. Okay. Mr. Mahmoud, maybe we'll just move on a bit.

Now, do I understand that your position is that for Port Hawkesbury Paper, if it is on the DR, it should get little to no credit for the IR?

I knew that was Mr. Bowman's position before yesterday, but I sensed that -- well, I guess your position was that the settlement agreement should be in place. But I thought you said yesterday that you also thought that if PHP was on the DR, it should get little to no credit for interruptibility.

First off, did you say that?

A. (Mahmudov) Sorry. Yeah, I said that if we did not consider parties to be bound by the settlement agreement parameters then, in the evidence, we did raise significant concerns with the dispatchable rider being too complex and having a risk of duplication with interruptible credits and also the significant changes from the current ELIADC tariff where the demand control at the moment is only 25 percent assigned to savings, right. Only 25 percent assigned to PHP and plus, you know, removal of that variable capital charge.

So we raised those concerns and we said that -- and I said, sorry, that if NSP is not able to demonstrate that, you know, there is no risk of duplication and the other points that we raised in the evidence, then probably, you know, the -- there is -- there's risk of allowing basically it being allocated 100 percent-- sorry. We're talking the interruptible grid.

Then there’s a risk of having interruptible credit being applied in a duplicative way in

addition to DR. So that's our concern.

So if -- so for this proceeding, I think our recommendation is -- has not changed. I don't think we said that it should change. But absent that understanding of the settlement agreement, yes, we did raise concerns with respect to interruptible credits duplication with the dispatchable rider, and that's what I mentioned yesterday.

Q. But what do you mean by duplication with the dispatchable -- the IR and the dispatchable rider? The DR gives an energy credit for a reduction in energy costs for PHP going down. It has nothing to do with demand and the company is able to ride through. The interruptible credit gives a credit for the right of the company to interrupt the customer, therefore, being able to avoid future capacity. The DR doesn't allow the company to avoid future capacity.

So how-- these are two completely separate credits, one of which applies to energy and one of

which applies to demand. And if you don't have an interruptible credit, if you only have the energy credit, then if you don't have an interruptible credit, then you're not interruptible and, therefore, the utility would have to plan for your load. You only -- the utility only gets the benefit if they pay the appropriate credit and have the right to interrupt you. Otherwise, how would NERC accept that, or how would anyone accept that to avoid capacity?

A. (Mahmudov) Yeah. And I think the challenge here is that large industrial customers, I understand that they also have interruptible credit. One thing they do not have is dispatchable rider.

In the case of PHP, both are being proposed. And in theory, you know, it explains that these are two distinct services.

So I think, you know, we can agree with that, that yes, they would be two distinct services, but if parties cannot demonstrate -- if NSP cannot demonstrate that they are distinct in practice, not in theory, but in

practice where they can say, you know, this part of the load is related to despatch rider and this part of the load is related to interruptible rider. And you know, this is why we're paying this amounts to PHP. If you cannot demonstrate in practice, I think it's just the risk is still there that, you know, it's just too -- too vague and too complicated to be able to say that other customers -- other utility customers are not paying the risk of carrying those costs because they're (inaudible); right?

Q. But interruptibility and the right to have the right to interrupt is like an insurance policy. You don't have to interrupt to say that. We've heard the other large industrial customers who are on operating reserve or telemetry and control are rarely, if ever, interrupted.

You pay for interruptibility so that you can avoid the cost of future generation. It's completely distinct product which the customer is providing to the utility than the DR, which is a product that runs

every 8,760 hours of the year and reduces an energy cost. By having the DR only, which is only related to energy, you then would not have the ability to not plan for Port Hawkesbury Paper as a firm customer because they wouldn't be interruptible.

A. (Mahmudov) I think under the current ELIADC, PHP is interruptible, correct? That's my understanding.

Q. Under the current rate.

A. (Mahmudov) Yeah.

Q. Correct.

A. (Mahmudov) And -- but there is no interruptible credit, if I'm not wrong.

Q. That's because in that rate, it's built into the overall value of the rate being a marginal rate and getting a lower contribution to fixed costs. So in exchange for a lower contribution to fixed costs, the company agreed to be interruptible and priority Interruptible. So there is a value exchange. There has to

be some compensation for Interruptibility in order for a customer to be interrupted, or I can't see any circumstance where a customer would just willingly agree to be interruptible.

A. (Mahmudov) Correct, yes. But for large industrial customers, then we see that there is interrupted credit, but then there is no dispatchable rider. So in the case of large industrial customers, there is no concern of the service being duplicated or this payment being duplicated. And our concern in the aspect of PHP's proposal -- or sorry, NSP's proposed PHP tariff is that there's two components which are being proposed. Both are credits to PHP in -- as proposed by significant and the utility was not able, basically, to produce or to explain clearly or to show, you know, how it will -- the mechanics, basically, of separating the two in terms of savings that it's generating and its relation to the payments.

Q. Okay. Mr. Malmudov. Maybe we'll -- we'll move on.

MR. MacDOUGALL: Mr. Norwood, if you could pull up the same document we were referring to earlier and if we could go to the third-last page in that document, the one that we were principally looking at.

Yes. That's it there. .

BY MR. MacDOUGALL:

Q. So if we could look in -- first in line 11. And we went through this, Mr. Mahmudov, earlier, just to just to be clear, if the -- if the IRR rate was used for interruptibility, then the credit to Port Hawkesbury Paper would be somewhere in the range of $5.6 million; correct?

A. (Mahmudov) Yes.

Q. Base amount. Okay.

And then if we can go down below and if we use the $13, you'll see the proposed amount would be $9,537,000; correct?

A. (Mahmudov) Correct.

Q. And both of these numbers are

without the priority interruptible that we talked about before. If there was priority Interruptible, they -- they'd go up by 10 percent or, in NSPI's view, $550,000, correct?

A. (Mahmudov) Correct.

Q. Okay. So you could have 6 million, let's say, and 10 million if you use priority interruptible; correct?

A. (Mahmudov) Yes.

Q. Okay. Now, if Port Hawkesbury Paper was going to go on the DR that is estimated at being between half of seven and 11 million dollars by Nova Scotia Power, that's 3.5 to $5.5 million, and you would take a 20 percent reduction as your proposal, the 3.5 would go down to some lower figure, maybe around 3 million or less and the 5.5 would also go down. So at the lower end you'd be under 3 million and under 5 million; correct?

A. (Mahmudov) Correct.

Q. Okay. Why would PHP ever consider

going on a DR rate that is unknown at the beginning of the year that could yield as little as $3 million in value to forego an interruptible rate that's known at the beginning of the year to create a minimum of $6 million and a maximum of 10 if Port Hawkesbury Paper's points on this are agreed to by the Board, while at the same time having to bear all of the operational and commercial risks that go with the DR?

So if you're going to give no value for the interruptibility, the -- the only economic choice is to forego the DR; correct? Or else you're forgoing the certainty of the interruptible credit value at the beginning of the year for a potential lower value at the end of the year.

A. (Mahmudov) Sorry. Is the question is ---

Q. Why would a customer do that?

A. (Mahmudov) Is the question about the choice between DR and interrupt? Sorry.

Q. Yeah. The question is, if you go on DR and you're on it, and then the argument is that for three hours in the year during the peak, the AR and the DR may be acting at the same time, you get no IR credit, then why would a customer ever do the DR? The data in front of the Board and in the record is that the IR credit, even at the low end, is more valuable than the DR credit even likely at the high end.

Why would any customer ever do that? You would be -- you would take the Interruptible rider and not go on the DR; correct?

A. (Mahmudov) I guess, you know, it would be a decision of PHP in that case. I cannot comment on that aspect. But I just wanted to ---

Q. Sorry.

A. (Mahmudov) Yeah. I just wanted to note that in the exhibit that -- that we just shared about the -- NSP's rebuttal evidence, NSP already expressed concern that that credit -- this credit amount that we're

looking at, the $13.107, is becoming too high. And I think they said that they want to review it.

So it may be that this interruptible credit amount, whatever it is, will also be reduced because at the moment, if you just look at this number here, $9.5 million of a credit to PHP under this scenario will be higher than the revenue collected from fixed charges for PHP. So $12, $14, they will not --

Q. Yeah, I don't think you answered my question. Mr. Mahmudov.

What I'm trying to say is don't even use the 9 million. Use the 6 million that we just talked about at the lower end. Would you ever advise a customer if it was a client of yours to become a DR customer without having any idea at the beginning of the year of the ultimate value of the DR, with an estimate that it could be as low as $3 million and with all its operational and commercial risks when, instead, you could go on an IR that, at a minimum, is going to give you $6 million.

Would you advise someone to say, well, take the IR with no interruptible value?

A. (Mahmudov) If it's only a monetary -- if it's only a monetary factor, like if you're only looking at the dollars, probably, you know, doesn't make sense to go with DR, but I don't know any other considerations that PHP may have.

Q. Well, the other considerations is all of the risks that go with DR that do not go with IR.

A. (Mahmudov) Yeah. So I have no information on those and cannot comment.

Q. Okay. Thank you.

MR. MacDOUGALL: Those are all of my questions, Mr. Chair. Thank you very much, gentlemen, principally Mr. Mamudov. Thank you.

THE CHAIR: Thank you, Mr. MacDougall.

Mr. Mahody, do you have questions?

MR. MAHODY: I do not. Thank you, Mr. Chair.

THE CHAIR: Okay. It's close to our mid-morning break. Mr. Melanson. Do you want to --

MEMBER MELANSON: I have no questions.

THE CHAIR: You have no questions.

I only have two, so why don't we finish and then we'll take our mid-morning break?

Mr. Norwood, if we could pull up Exhibit N-19, please. And I'm looking for page 7 in the PDF, the last paragraph just before the Section 4.2.

QUESTIONS BY THE CHAIR

Q. So there's a statement here that this is the only -- the questions I have relate only to this particular point so I'll read this particular paragraph into the record:

> InterGroup agrees with the concerns raised by NSP that including only the firm 8 MW of load would under-represent the degree to which PHP makes use of and benefits from the transmission system. In InterGroup's experience this is a common problem with "interruptible" loads that reflect a considerable portion of a

> customer's ordinary electricity needs. While there are alternative cost allocation methods that could help address this, in the context of the SA, the load parameters modelled by NSP in the application are reasonable and should be approved.

So I just want to break that down a little bit and ask for some elaboration.

First, in terms of the opinion that's expressed, that eight megawatts would under-represent the degree to which PHP makes use of the benefits from the transmission system, could you elaborate on that for me a little bit in terms of what -- what you see there and the potential extent of the problem from your perspective?

A. (McLaren) Yeah, maybe I will start, Mr. Chair, and Mr. Mahmudov can jump in.

I think our concern we're identifying here is that, at eight megawatts, it's just not -- it's not a practical business operating load. And so including that amount, that sort of what I might call critical power rather than just firm, would under-represent the degree to

which the transmission system needs to be built out to be able to provide PHP with the much higher order of magnitude level of loads higher that are more typical of its operating profile. And I think NSP in response to an IR sort of indicated that, in their view, there are costs associated with having a transmission system that can provide that volume of power to PHP that's -- that's more typical of its operating requirements.

Q. And my understanding, and I'm not sure I understand it correctly, but if I do, is that PHP's position is that those transmission costs as well can be -- can be avoided because of the interruptible nature of the load. You don't agree with that?

A. (McLaren) Well, I understand that that Nova Scotia Power's position first is that that's not entirely true with respect to the transmission system. I think the response to our IR said that the transmission system has to be able to supply those loads so it doesn't fully avoid the cost of having the transmission network

that can supply PHP with those loads. That's my understanding of NSP's response to our information request.

Q. Okay. So in this particular paragraph, you're just -- the opinion that's expressed is that -- just based on the position or the response that Nova Scotia Power gave you in the EIR response?

A. (McLaren) It relies on that to a fair degree. I would also say it relies a bit on my experience of -- with these types of customers, you sometimes have problems clearly identifying what -- what do we mean by firm and what do we mean by interruptible. And there are, you know, examples from other places where there have been concerns about cost shifting as a result of avoiding, you know, a single coincident peak or one coincident peak per month. And so there's a bit of difficulty, in my view, in segregating what is -- what really should be called firm and what should be more correctly called interruptible.

Q. Okay. And that kind of bleeds

into the next piece of elaboration I was going to get from you. It's the next sentence where you refer to this as a common problem where interruptible loads are considerable portion of the ordinary electricity needs.

And you've indicated a moment ago you see this in other jurisdictions and there's an issue with avoiding costs at the critical peak.

In this particular case, Nova Scotia Power uses the 3 CP methodology, so it's not one particular point in time. Does that does that address the issue?

A. (McLaren) I don't think so. I know we included some information from the Alberta process where they use 12 CP and it's still a concern that there's, you know, potential for cost shifting. And my understanding is that's part of the reason that Alberta is going through a big transmission tariff redesign is because of concerns around single points in months.

Q. And you identified in the next sentence that there are alternative cost allocation methods

that could help address this. And I wasn't sure what alternative cost allocation methods you were referring to there.

A. (McLaren) Yeah. I think we got an information request from the Industrial Group on this one, and that was sort of where we settled the information about the Alberta process. And so I don't have a perfect answer for you in terms of what I would -- would recommend going forward. And like I said, I think our evidence is premised on the -- the understanding that we thought the settlement agreement as we understood it was reasonable for the time being. But in the future, there may be a need to explore other methods and some of what we see in other places are expanding the number of coincident peaks beyond three to 12, maybe even more hours than that, just to try and remove the sort of influence of one or two hours in a period.

Q. And in terms of the cost of service methodology that Nova Scotia Power employs in this jurisdiction, I take it whatever those alternative cost

allocation methods are, those -- those aren't currently included in the methodology here in Nova Scotia?

A. (McLaren) Correct.

THE CHAIR: Okay. Those are my questions. Thank you very much.

Just check around the room to see if there's anything arising from those.

MR. MacDOUGALL: I actually do, Mr. Chair.

THE CHAIR: Okay. Anyone else other than Mr. MacDougall?

Okay. Go ahead. Sorry.

MS. POWER: I may have one question, but I'm okay with Mr. MacDougall going first.

THE CHAIR: Probably better if you go first.

MS. POWER: I just needed a minute, Mr. Chair, to sort my question, but I'll give it a try and hopefully it lands.

QUESTIONS ARISING BY MS. POWER

Q. So on interruptibility, if PHP is not being treated as interruptible, it would mean that that portion of their load would be considered firm; yes?

A. (McLaren) Yes.

Q. And in order for Nova Scotia Power to not plan for their load, they would have to be considered interruptible NERC requirements. Is that correct?

A. (McLaren) I'm not familiar enough with the planning criteria in Nova Scotia to comment.

Q. Okay. And would you be familiar with the MPCC directory design and operation of the bulk power system criteria?

A. (McLaren) I haven't looked at that in quite some time.

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

THE CHAIR: Mr. MacDougall?

QUESTIONS ARISING BY MR. MacDOUGALL

Q. Mr. McLaren, you were making a reference there to a demand amount based on a more -- more typical of a Port Hawkesbury Paper's operation. But first off, just going off the Chair's question in that regard, here Winter 3 CP is what's used for the demand allocation; correct?

I believe you agreed with that earlier. Mr. Mahmudov did.

A. (McLaren) Yes.

Q. And there was a recent cost of service process in which that was confirmed?

A. (McLaren) Correct.

Q. And you participated in that process?

A. (McLaren) No, I did not.

Q. Did the CA -- are you aware if the CA participated in that process?

A. (McLaren) I understand the CA was

represented in that process, yes.

Q. Okay. And on the record here, we have that for '24 and '25 there was a historic peaks of potentially 28 megawatts, but then we heard yesterday that there may be a mismatch between what NSPI filed and what PHP has, which may be as low as 11 megawatts versus, I think it was, 99, so that 28 megawatts could come down even further for the historic recent 3 CPS. Did you hear that evidence?

A. (McLaren) I heard the evidence of the mismatch. I didn't follow the rest of it through the logic train you just went through necessarily.

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

Thank you, Mr. McLaren.

THE CHAIR: Thank you, Mr. McLaren, Mr. Mahmudov, I appreciate your participation in this -- in this matter and your assistance to the Board. That concludes your testimony, and you're free to go.

Thank you. So it's 20, 22 minutes after 10:00 by my computer here.

So we'll come back at 20 to 11:00. Thanks.

--- Upon recessing at 10:22 a.m.

--- Upon resuming

THE CHAIR: Okay. I think we're all set. Ms. Rudderham.

MS. RUDDERHAM: Good morning, Mr. Chair. We have Patrick Bowman here. I'm not sure if you wanted to start by affirming him and then getting into the questions.

PATRICK BOWMAN, Affirmed

DIRECT EXAMINATION BY MS. RUDDERHAM

Q. Good morning, Mr. Bowman. Can you start by stating what your occupation is for the record?

A. Yes. I'm the principal consultant of Bowman Economic Consulting.

Q. Okay. And you filed evidence in

this proceeding as Exhibit N-25, which has attached to it your curriculum vitae.

A. Yes.

MS. RUDDERHAM: Mr. Norwood, if you don't mind bringing that up, Exhibit N-25, and starting at PDF page 20, just for ease of reference.

BY MS. RUDDERHAM:

Q. And Mr. Bowman, the CV is in front of you right now. Can you confirm that this accurately sets out your education, your experience in utility regulation and your professional qualifications?

A. Yes.

Q. Could you briefly describe your educational background for the Board?

A. Yes. I have a Master's degree in Natural Resources Management from the University of Manitoba, where I focused on areas of resource economics.

I've been working in the field of utility regulation since approximately 1998, and most of

that time I was a principal at InterGroup Consultants. And since 2000, I left InterGroup as a principal and I've been working on my own.

Q. Could you briefly also describe your professional experience as it relates to utility regulation, cost of service and setting utility rates?

A. Yes. I have been involved primarily since 1998 in utility regulation. I have worked in most jurisdictions in Canada other than Quebec, and appeared before every regulator as an expert that does that sort of thing throughout the country. And that has been -- covered primarily electricity utilities, but also occasionally natural gas and water.

And in my practice, I have worked with small consumer groups, industrial groups, with utilities and with regulators.

Q. And just to follow up on -- on something you said, can you just confirm for the record which provinces you've worked in?

A. Yeah, I have -- I've been involved in utility regulation in every jurisdiction except Quebec.

Q. Okay. And appended to your CV at PDF, page 25.

MS. RUDDERHAM: Mr. Norwood, if you don't mind pulling that up.

BY MS. RUDDERHAM:

Q. This is a table that summarizes all the proceedings that you've been involved in; correct?

A. Yes.

Q. Okay. And you've previously appeared before the Nova Scotia Energy Board.

A. Yes. One time.

Q. Okay. And you were qualified as an expert at that time?

A. Yes.

Q. Okay.

MS. RUDDERHAM: Mr. Chair, the witness's qualifications are set out in in the filed CV.

And the witness has extensive experience and has previously been qualified as an expert in this jurisdiction and has provided evidence on behalf of a variety of different participants in utility proceedings.

The Industrial Group would tender Mr. Bowman as an expert in the fields of utility regulation, cost of service, cost allocation and utility rate design.

THE CHAIR: Any questions on qualifications or objections?

He's so qualified.

BY MS. RUDDERHAM:

Q. And Mr. Bowman, as we've indicated, you filed written evidence in this proceeding as Exhibit N-25?

A. Yes.

Q. And you've also filed responses to information requests from PHP at Exhibit N-28?

A. Yes. PHP was the only party to ask me written questions.

Q. And were those documents prepared by you or under your direction and supervision?

A. Yes.

Q. And have you reviewed those documents in preparation for today's hearing?

A. Yes.

Q. And in your opening statement, which you'll read into the record shortly, you've -- you've noted that there was one error in your response to PHP IR-1 in which you used the phrase DR, but you meant to say IR. Is that correct?

A. Correct.

Q. Were there any other corrections, revisions or updates to your evidence that you wish to make either for your report or for your responses to information requests?

A. No.

Q. And are the facts, assumptions, analysis and opinions contained in your evidence true and

correct to the best of your knowledge and belief?

A. Yes.

Q. And do you adopt your evidence at N-25 and N-28 as your evidence in this proceeding?

A. Yes.

MS. RUDDERHAM: and as noted, we -- there is an opening statement for Mr. Bowman and I -- we would ask that he be given the opportunity to read it into the record now.

THE CHAIR: Go ahead, Mr. Bowman.

OPENING STATEMENT BY MR. BOWMAN

MR. BOWMAN: Thank you.

Nova Scotia Power proposes a new tariff applicable to PHP, effective January 1st, 2027. The proposed ELID is an "above-the-line" tariff with riders reflecting PHP's unique load flexibility. Unlike the existing below-the-line ELIADC tariff, an above-the-line tariff allocates asset based system costs to PHP, not just the variable or marginal costs.

It is common and appropriate regulatory practice for a tariff to credit a customer for the value created by adapting its load. However, the specific form of the ELID is, to my knowledge, unique in Canadian regulatory experience in the wide array of credits and benefits offered to PHP.

I conclude that NSP's proposal does not reflect proper regulatory considerations for an above-the-line tariff. With the changes I recommend, I conclude that the ELID should be approved.

My recommendations are intended to align the ELID with a principled step-by-step design of an above-the-line tariff: establish a typical industrial load profile before application of the riders called the customer baseline; then apply the dispatchable rider or DR to credit PHP for shaping its load in response to marginal system conditions; and finally, apply the interruptible rider to credit any remaining capacity expected to be interruptible.

In regard to the customer baseline CBL as an above-the line-customer, the cost-of-service calculation should include all energy forecast to be sold to PHP from the integrated NSP system, net of Goose Harbour Lake wind, which is largely a pass-through and all PHP capacity requirements determined before application of the DR and IR.

NSP's cost-of-service study does not reflect a proper CBL for PHP peak demand. Instead, it relies on PHP's average historical experience under the ELIADC, where PHP was dispatched down during peak hours. Those historical peaks are not representative of PHP's underlying load and using those hours as the basis for future peak demand estimates effectively credits PHP a second time for past load shaping, for which it has already received credits through the ELIADC.

Based on publicly available information, my assessment is that PHP's CBL peak demand for cost of service purposes should be closer to 120 MW

instead of the 65 proposed in the application.

If NSP has more detailed and reliable peak demand data supporting a more accurate CBL, I agree it should be used. Based on the evidence currently on the record, however, including PHP's rebuttal that notes that absent a DR, PHP would operate at a high load factor throughout the year, 120 megawatts is a reasonable representation of PHP's typical CBL as a high load factor customer before the DR or IR are applied.

So my first recommendation is to set the CBL at 120 megawatts absent an updated value for NSP, and that's for cost of service purposes.

The dispatchable Rider. The DR credits PHP for shifting its load in response to marginal system costs. This is a substantial and unique benefit, particularly because it applies to approximately 800 gigawatt hours of PHP consumption, even though almost 75 percent of that energy is forecast to come from PHP's own wind generation and is not purchased from NSP supplies.

I do not object to PHP receiving credit for its *bona fide* effects on the system relative to its CBL. However, NSP has not required sufficient practical controls over PHP's dispatch in exchange for this unique benefit.

My recommendation 2 is to increase the system operator's control of PHP's dispatch at peak times. And recommendation number 6 is to require the operating procedures associated with this to be approved by the Board.

I expect it will be difficult to properly establish the granular CBL with precision, and this is with respect to the DR. This is -- this is needed to calculate the DR under NSPI's proposal, which Bates White also noted. To avoid the over-crediting PHP, some of the benefit-sharing aspects of the ELIADC mechanism should be retained to protect remaining customers.

The DR applies not only to the approximately 300 gigawatt hours PHP is forecast to

purchase from NSP supplies, but also to approximately 500 gigawatt hours of its own wind generation. This added potential credit of the DR to PHP, unrelated to NSP supplies, further supports the principle of benefit sharing with other ratepayers.

So my recommendation 3 is to retain some aspects of benefit sharing.

Number 3, the Interruptible Rider. The IR credits PHP for load expected to be interruptible at peak times under system operator control, which brings generation planning benefits. At this stage, PHP's load should reflect the CBL as modified by the DR load shaping.

As with the large industrial, LIIR, customers, NSP should credit PHP only for load that is likely to be on the system at peak times. If a customer is expected to shape it slowed down at peak times such that its load is already off the system, NSP need not compensate the customer for that reduction through the IR. The IR should only apply to additional interruptions the utility

seeks to claim beyond customer load shaping. Similarly, if PHP is expected to shape its load away from peak times for DR or any other reason, there should be no IR credit.

LIIR credits are adjusted to reflect this likelihood consideration, and PHP should be treated no different.

According to the historical ELIADC data, PHP was dispatched down whenever an interruption occurred under the IR peak times. If this is also expected to be the case in future, there would be little to no IR credit available to PHP.

Recommendation number 4 is to conclude that there is little to no credit due under the IR.

I take note of NSP's reply evidence which indicates that PHP's load at 3 CP times will not necessarily be always dispatched down, and NSP would therefore need to include some PHP load in generation system planning absent the IR. If a proper CBL for PHP indicates expected material load (above 8 megawatts) at 3

CP, after application of the DR, then the PHP -- then PHP should receive IR credit for that capacity. I had already acknowledged this in my response to PHP IR number 1. For example, this would apply if the past average 3 CP load of 57 MW after responding to the ADC remains representative of future peak load expectations under the DR. In this case, PHP would not receive IR credit for all 120 MW, which NSP appears to suggest, but only for the portion expected to be online (for example, 57 MW).

In regards to the priority IR, NSP also proposes a further 10 percent IR credit for "priority" interruptibility, meaning PHP would be interrupted before other customers.

I do not find this appropriate for three reasons.

First, PHP is rarely interruptible in practice under the IR because it would already have been dispatched down under the DR.

Second, PHP is not priority

interruptible compared to some IR customers who do not participate in the telemetry and control option. Note this is contrary to Brubaker's rebuttal evidence claiming that PHP is the first customer to be interrupted on the system.

And third, labelling PHP as priority interruptible does not create any new interruptible load or value to the system.

So recommendation number 5 is to eliminate the priority Interruptible credit.

PHP has rejected the NSP version of the ELID, and instead proposes an eight megawatt peak load of 100 percent revenue-to-cost ratio and added ancillary services related credit. These proposals are not appropriate and should be rejected.

My recommendation number 7 is to reject the PHP proposals.

I would also note issues raised by Synapse suggesting that some of the above ratemaking principles should be abandoned simply to arrive at a rate

PHP will accept. That would be inconsistent with good ratemaking practice and would provide a concession unavailable to other regulated customers.

As I set out in information request responses, if the full suite of measures above were adopted to the fullest extent (for example, PHP received no IR at all, but captured the full estimated benefit of their DR), the total cost would be on the order of 48.5 million for 2027. It could be less, for example, if NSB calculates a CBL for PHP that has a viable IR load, such as the 57 MW, then the annual bill would be reduced by nearly $6 million. As a course measure of reasonableness, the entire LI class has costs of about 72.9 million, even though PHP's peak load is larger by roughly 50 percent than the LI class, and PHP's energy usage is lower by roughly 50 percent. For reference, before IR, the cost of demand is about 30 percent of the cost basis for LI and energy cost is about 70.

In their rebuttal evidence, NSP appears

to dismiss my concerns over complexity of the DR in practice, and the creation of a CBL for year-end allocation purposes, which NSP indicates is not significantly more complicated than under the ELIADC. I believe NSP misstates aspects of my concern, which do not only relate to future practice under the ELID versus past practice under the ELIADC, but to future practice where only 300 gigawatt hours are purchased under the ELID but 800 gigawatt hours are theoretically compensable under the DR, a complexity driven by the new wind.

Brubaker's rebuttal (page 4) indicates I have proposed discriminatory ratemaking by suggesting PHP's peak load for cost-of-service purposes use average demand while other classes use anticipated 3 CP demand. This is not correct. I propose that PHP used the expected 3 CP peak demand based on a high load factor prior to DR, which PHP's own witnesses confirm should be assumed if there were no DR. My concern is that NSPI's proposal is discriminatory towards PHP by double crediting

dispatchability. The 65 megawatt peak is discriminatory, as it reflects a lower load than PHP would operate absent DR. No other customer class gets credited to reduce their load at system peaks (through ADC), and then additionally claims a cost of service credit because their peak was lower.

Finally, Brubaker routinely appears to suggest that the DR (formerly the ADC) is about energy, not capacity, and that it is optional for PHP to respond. Yet the effect of Brubaker's eight megawatt 3 CP proposal is to credit PHP for firm capacity effects of the DR/ADC, as if PHP can be expected to be relied upon in future as a capacity resource (for both generation and transmission purposes). If the DR/ADC is only energy and not required participation, then there should be no capacity benefit applied, hence the 120 megawatt flat load assumption I have proposed.

MS. RUDDERHAM: Mr. Bowman is available for cross examination. Mr. Chair.

THE CHAIR: Thank you.

Consumer Advocate.

Sorry. I skipped Nova Scotia Power.

MS. POWER: If we can go last, Mr. McGrath. Thank you.

THE CHAIR: All right.

I didn't skip Nova Scotia Power.

Consumer Advocate.

CROSS-EXAMINATION BY MR. MURPHY

Q. Good morning, Mr. Bowman. I only have a few questions for you.

MR. MURPHY: Mr. Norwood, if you could pull up Exhibit N-25, and it's page 6 of the printed copy.

That's the right one. Yeah.

BY MR. MURPHY:

Q. At about line 15, you indicate:

> This order of operations for pricing the PHP supply is important for logical consistency under the NSP proposal.

And then you set out the order of operations that that you're proposing.

And I'm just wondering if you can elaborate on why you say that's the appropriate order of operations in terms of deciding what the different variables or parameters of the ELID rate should be.

Q. Yes. Perhaps I'll start with the comment that I had made that this rate is unique and complicated and there's not a lot of regulatory precedent to rely on in figuring out how to come up with the pricing principles.

So I considered that the appropriate approach would be to go back to the first principles of what one is trying to achieve and to work forward, if you like. So the first underlying principle that was, as I understand it, directed by this Board and that the parties were seeking to apply is that PHP becomes an above the line customer in the Cost-of-Service Study and that they would be consuming power based on the idea of a of a flat load.

And I use the term CBL for that. CBL seems to get used for a lot of different things, but generally I think it's shorthand for a high load factor, flat load.

So first, one would -- would move them to an above the line customer and then seek to apply the different riders and the like that are available.

I submitted that the second consideration that would apply would be the DR and I submit that that would apply second because it applies to every hour of their operation. It's integral to the way that their -- that their load works. And so that you would then give them the opportunity to shape their load. And a reminder, it's not just the load in the cost of service. It's all 800 or so gigawatt hours that they consume. So it's also giving them the opportunity to see savings from shaping their own wind. And so you apply that to -- the to the shape of their load second, and for which they will receive a credit.

The third piece, which is -- has some

experience and practice in this jurisdiction for costing is the interruptibility. And with respect to interruptibility, we have some established principles that say one would look to the likelihood of interruptible load being available in coming up with the pricing for that and by likelihood it's a 3 CP or it's load available at peak times.

This morning Mr. MacDougall walked through with Mr. Makhmudov the fact that for the LIIR customers, the value of credit they get is based on their load at 3 CP, approximately 70 megawatts or so. And even though that credit is paid out over something like 100 megawatts per month or 100, 110 or something per month of demand billing determinants, their credit is only for the load they expect to have on the system at those peak times.

And then finally to determine if there should be a priority interruptibility.

And I think the critical element there is between steps two and three. It's having applied the

dispatchability rider, the question is what is left for interruptibility. And I think that's where probably the largest divergence applies within this proceeding.

Q. Perhaps we can turn to Exhibit N-28. These are the IRs that were asked of you from Port Hawkesbury Paper. And it is IR-3(d).

We can look at the question first.

And so in (c) you were asked:

> Please explain whether the proposal suggests that the capacity value reference would be used in place of the 3 CP demand allocator currently in use in the cost of service.

And then (d):

> If the answer to subpart (c) is in the affirmative, would Mr. Bowman suggest that other customer classes use the average demand value in place of the 3 CP demand allocator for cost allocation? Please explain.

And then we can flip to the answers.

And then you provide your answers there. So your answer to (c) was "Yes".

And then in (d) you indicated that,

"No, the same process would not be applicable to other customer classes".

And then you -- first you note:

> The 3 CPP demand is the standard approach for establishing above-the-line rates when the company can measure and report passed above-the-line loads.

And I would just ask you if you can first describe what the purpose of the 3 CP methodology is.

A. Yes. The 3 CP methodology is one of the steps used in the Cost-of-Service Study. The methods in the Cost-of-Service Study are established to track cost causation and the principle underlying the 3 CP is that customers who cause loads to be on the system at the highest times of the year cause investment in assets in general.

It's a shorthand way for saying which customers cause us to have to build assets related to being able to supply the load at the peak times.

Q. So it's a -- it's a cost causation

tool, I guess.

A. Yeah. Everything in cost of service is cost causation.

Q. And I've sort of thinking -- you tell me if I'm getting it wrong, but I think of it as sort of a snapshot of demand power use by a utility's different customers intended to sort of capture their -- their general usage of the system.

Is that the right way to think about it?

A. Yeah. There's -- I have -- I have learned in my career that "use" can mean different things for different people so I'm always cautious about using the word "use". It's a lot easier to go to "cause", but -- because there's less -- less debate around that term, although there's still a lot.

So the idea is what -- what type of what -- which customers cause investment in the assets and the -- the type of assets we're talking about are caused by

consumption at peak times.

Q. And you go on in your answer there to indicate:

> It's not possible for PHP as the past loads occurred under an ELIADC regime, which undermines the use of this data for pre-DR load projections a the ATL scenario in the cost is to be run. For this reason, a different solution is required for PHP.

Can you just elaborate on that? Why is it not possible to use this -- the normal 3 CP method for PHP?

A. Well, in each instance what you're trying to do is look at the anticipated customer class load at the peak time for the test year that you're running the cost of service. For most customer classes, the best starting point for what they will use in the future -- for their loads in the future is what they used in the past.

That isn't always the case. It works well for -- for businesses, for example, for small

businesses or for residences. It doesn't necessarily work well for large industries.

So when you come to the large industrial customers, they use a mix of sort of past experience, but also customer surveys and plans and adjustments. For example, if a customer was interrupted at a peak time, you don't -- you're already going to credit them for the -- that IR, the interruption in the Cost-of-Service Study in a later step so you don't -- you don't sort of re assume that interruption into their base. You credit that through a different mechanism.

So you don't just look at what they ran in the past year. And I'm saying the same is true for PHP. You -- you wouldn't just look at the past as the predictor of the future because the past is already -- is already coloured by subsequent riders and steps that come after you run the cost of service -- the main cost of service analysis.

Q. Okay. And just the way that you

presented that answer, are you saying that there's a standard practice or approach that Boards should or do use when, you know, applying a 3 CP method to larger customers who may have Interruptible loads?

A. Yeah. And it is applied here, yeah.

The -- that you -- you rely on the load forecasting prepared by the utility. The load forecasting is a separate process outside of the Cost-of-Service Study, but it would be heavily reliant on historical data. But it's not the only thing that it looks at.

And with respect to something like industrial customers who are interruptible, you may have to adjust back in the interruptible load so that you pick up what you expect their load to be.

MEMBER MELANSON: Could I step in just on the issue of the historical data and the impact that the ELIADC had on the historical data?

Since the proposed ELID proposes a

dispatchable situation similar to what -- at least in practice, to what -- what the ELIADC has, why can't you just keep using the same historical data over time? Because it's going to be impacted every year for the foreseeable future if you're going to do the ELID as it is now.

MR. BOWMAN: Well, I would suggest there's probably two reasons for that.

One is because of the instability and the numbers that come -- arise from that, so there's a practical consideration. For example, Nova Scotia Power effectively used that in part to come up with the 65 based on the 2022 and 2023 peaks under -- 3 CP peaks under ELID. We saw that data.

But if you then look to 2024 and 2025, we originally came up with a number like 28 megawatts, but now we know the 28 probably includes a misreference in it and it's probably something more like 13 megawatts. And then we heard that that includes the load of the biomass so

the -- the peak's actually more like nine if you look at PHP's own load in '24-25, so I don't think that that leads you to an approach that -- that one could apply year after year and come up with a rate that has any sort of stability or the other -- the types of criteria that we like to say is part of a good rate.

And the second reason is that that same peak is then applied also for transmission. And I don't -- I haven't heard a lot of contrary evidence to the idea that NSP does have to plan transmission and cost transmission not on the basis of interruptibility, that it does plan its transmission and doesn't offer a credit for that. And I know that if you look at the large industrial customers, they don't get a credit related to the transmission costs. They only get the -- the generation cost. So I think that's the -- that's the second reason.

But moreover, I think it is appropriate to start with the idea of what the load would be absent the riders and then apply the rider credits intentionally.

If you do it the way you're talking about, the rider credits sort of come in through the back door, if you like, into the costing. And I think it's a -- it's a lot less transparent and it risks causing this type of instability.

MEMBER MELANSON: For a dispatchable customer -- client, for some a dispatch rider is suggesting that you should never use the historical data as a basis, your starting basis. Is that your view?

MR. BOWMAN: Right. Dispatchable customers are not the norm so it's hard to say what the ground rule is. But ---

MEMBER MELANSON: I'm not asking what the norm is.

MR. BOWMAN: Yeah.

MEMBER MELANSON: From your perspective, do you ever use the historical data to establish the baseline?

MR. BOWMAN: You would -- you would use

aspects of the historical data, but I just don't think you would slavishly report it. I think you would try to take the historical data to give you information about how the customer operates and then apply it to a forecast about how they would operate absent the riders and then apply the riders.

BY MR. MURPHY:

Q. And just to pick up on that point, as I understand your evidence, it's the problem with using there -- only the historical data is that that already takes into account interruptibility and the dispatchable nature of the ELIADC and so you're crediting them on the front end and then also applying that same credit on the back end.

Is that -- is that what you're sort of suggesting?

A. Yes. And further, in the NSP proposal, you're kind of splitting the baby. You're kind of -- you know, we know that their baseline load, their

flat load, would be up around operating mode 5 or 6 or the like, which gets you to around 100 to 120 megawatts. And we know that their interrupted load will be down at eight. And it's be -- kind of go somewhere in between and find some years that conveniently support 65, but I'm not sure what their -- what their approach will be in future years.

So I think they've -- and I don't think their, their case is much different than this. They found a solution for the time being and then say there's a bunch of more work to be done in the future. And all I'm suggesting is that from -- starting from a first principles approach, there's probably more coherence to both the Brubaker proposal and my proposal than to NSP's that is sort of a convenient solution out of a negotiated settlement and a year that happens to average to the right number.

The issue I run into is the -- to me, the starting with a CBL in the -- in the cost of service makes the most sense. And then the question is, what are

the riders worth and the DR rider.

I don't take a lot of issue with the way that one applies a DR rider and comes up with a credit to PHP. In my submission, if an industrial customer can create value by shaping its load, they should get the credit for that. So I don't have any problem with that DR -- that aspect. And I don't have any problem with them being paid for interruptibility. It's just a question of how much interruptibility are we really getting from that customer?

And you know, I can see rationales that come to any number from zero to 100, 112, I guess if you start with -- with 120 and take out eight. But I think that's where sort of NSP has a -- has a role to come in and be quite specific about what they consider that DR to be in the Cost-of-Service Study -- or what the CBL is, sorry, in the Cost-of-Service Study, what the DR would do to that, and then how much interoperability really is left in practical terms.

Q. And you heard PHP's questioning of Mr. Mahmudov earlier today, and Mr. Mahmudov indicated that -- he acknowledged the difference between dispatchable and interruptible on a theoretical basis, but in practice suggested there was some difficulties with applying both of these credits. That doesn't seem to be necessarily your view from the evidence.

I think what you suggest is that there should be an interoperable credit. It's more about the value. Is that -- do I have that right?

A. Yes, absolutely. That is correct. There should -- there should be an interruptible credit for any load that is expected to be on the system after application of the DR and for which NSP can, in practice, call.

Now, that's -- just to, again, go back to what Mr. Mahmudov was going through, if you're a large industrial customer, you're -- or a group of them in this case, their loads might be 100, their loads might be, you

know, 105 at times, their loads might be 80. Like their billing determinants lead to 115 or something on average. They're only credited for 60 or 70 -- or approximately 70 because that's all that's expected to be on the system at peak times is the 70. But all of their load other than what they protect is interruptible. There are times when you -- when NSP might be able to call for more than 70 megawatts and get that interruption, if it happened to be in an hour where the customers are running higher than anticipated, and then anticipating the Cost-of-Service Study for the purposes of 3 CP.

So it's not a matter of how much megawatts you might get. It's a matter of how much megawatts you build into your system planning, and then you credit back for being -- for being interruptible.

Q. The large industrial interruptible rate, there's been some comment about whether that may be a suitable alternative for PHP if they ultimately choose not to take service under a rate -- under an ELID rate that

gets approved by the Board.

Have you given that any thought?

A. I've only given it a small amount of thought, but my main concern with that is not their eligibility for the rate, it's the costing and the costing in a Cost-of-Service Study. We create classes because you have a group of customers who are similarly situated and use power in similar ways, right. So we can put residential customers together because we generally assume they're pretty similar, but we don't put residential customers with restaurants, even though they might use approximately similar amounts of power because they use it at different times and in different ways. So we look to whether these customers can viably be considered a class.

And I take no issue with the idea that PHP would be an industrial customer. I'm not sure, once you have Goose Harbour like wind on whether they look like other industrial customers, so they may still end up as their own class costed according to the same LIIR

principles, but not mixed in with the other large industrial customers who don't have that type of, you know, own non-firm generation behind the meter, for example.

Q. From that, I take it that the -- it's not that the principles that govern the LIRR (sic) tariff are not applicable to PHP. It's more about whether they should be in that same group with that other group of customers or whether it should be more of a LIIR2 sort of approach.

A. Exactly. Correct. Just like some -- some jurisdictions determine that rural residential looks different enough than urban residential they'll create two classes because their impacts on the system are different. So it would be the same kind of thing, does PHP look enough like the rest of the LIIR customers that you'd mix in a class or do you create a PHP class.

And it may be that class applies to more than PHP. It may be that it applies to other customers who -- who might come on the system who have

behind the meter, you know, non-firm generation themselves.

Q. Okay. Thank you, Mr. Bowman. Those are all my questions.

Thank you.

THE CHAIR: Thank you.

Small Business Advocate.

MS. MacADAM: Thank you, Mr. Chair.

CROSS-EXAMINATION BY MS. MacADAM

Q. Good morning, Mr. Bowman. I just have a few questions to help clarify my understanding of your evidence.

If we could just to help bring up Exhibit N-44. That's the opening statement that you just shared with us, Mr. Bowman.

And this is probably the easiest way to refer to your recommendations.

If we look at your recommendations, so if we look at page 2, your recommendation number 2, I Just wanted to ask you a couple of clarifying questions.

Your recommendation here says if we read:

> Recommendation #2 is to increase the system operator's control of PHP's dispatch at peak times.

So could you just explain what you mean by increasing control there?

A. Yes. But I will say that I put it in as a concept rather than a particular prescriptive approach.

But in general, my understanding of the of the approach under the ELID -- or sorry, the ELIADC under the current method is that there is somewhat different financial consequences to PPH for Cause Code 5 events, which are the election by PHP to ignore a dispatch from NSP and that from what I read of the evidence, that type of unique characteristics for Cause Code 5 events versus other will effectively be gone in the future.

And so I wasn't sure -- I'm not an ELIADC expert. I was never involved in the design of that

rate or implementing it. But -- but my sense was that if you're going to have a customer that is being offered this significant opportunity to be dispatchable that it probably needs to be more than a -- you know, a suggestion from NSP's operators.

Now, that may not be necessary if the conclusion is they work well together and PHP, you know, in most cases, follows the dispatch in any event. But my concern is that it be more than a -- than sort of an equal opportunity to just ignore the dispatch.

Beyond that, I don't have any specific recommendations about how to do that.

Q. That helps.

So in -- from what you've just shared, you said under the ELIADC there were some cost under Cause Code 5. I believe you said that there were some cost outcomes or cost consequences for not following it.

And so without this increasing the control, are you suggesting that PHP wouldn't, I guess,

under -- if you increase control, they wouldn't have the ability to reject or refuse? Is that what you're suggesting with the increasing control?

A. Or it may just be that the cost consequences are somewhat increased compared to just at any other hour. I think a way to communicate that that these are -- you know, sometimes -- sometimes NSP may may just be issuing a an operating mode to balance a week, but other times it may be issuing a one that says, you know, this one -- this one really matters.

It may be by being able to relay that these are higher cost hours and letting PHP know that, at the end of the year, the cost consequences will be -- will be higher for this hour or it may be something that gives a greater degree of practical control, but I think you will have heard the evidence about the complexities that go on between the two -- the two parties. And so I think at the time -- I hadn't heard that evidence at the time, but the understanding I had from the technical workshop was that

the pricing for the DR is designed around the idea it's just a suggestion or it's just a hint about how they should behave. And that seemed inconsistent with the idea that under ELIADC, Cause Code 5s had some -- some amped-up consequences. And I was just curious about how to -- how to keep some degree of communication of urgency on the -- certain hours where -- where PHP -- or NSP might want to communicate that this one really matters.

Q. And so that may have answered what I was going to ask you next.

So maybe I'll just rephrase it to see if what I'm understanding is correct because I think you said you hadn't thought through in great detail in terms of what that control would look like, but you gave the example of these cost consequences that we have in the ELIADC. So I'm assuming, then, that if it's cost consequences and the ability for NSP to say this one really matters and, if not, there will be cost consequences, would that then resolve if there are safety or security issues raised around NSP

having complete control over PHP and PHP not being allowed to refuse the request?

A. Oh, I wasn't talking about anything like -- like telemetry and control or being able to sort of to enforce those moments. That's -- that's the interruptible rider factor and it already has the rules for if -- if one -- if NSP really wants to make sure something happens, they have they have that control under the telemetry system.

This is just a -- my way of suggesting a certain pushback to information that was shared at the technical workshop that kind of said, these are just suggestions, if you like, to PHP about how to operate.

Q. Thank you. That's helpful.

So I wanted to ask you now, moving on to recommendation 3 -- it's probably still -- if we scroll down, you can see it on that same page in the opening statement just to -- rather than taking you to the evidence.

And your recommendation there is to retain some aspects of benefit sharing.

I just wanted to confirm, is your main reason for recommending in your evidence -- and we see it here in the opening -- that the benefit sharing aspect of the ELIADC, as I understand it, be retained due to NSP's inability to precisely predict the CBL, the customer baseline?

A. Yes. And I think Bates White covered this in more detail than me that the DR mechanics at the end of the year are going to involve some discretion on NSP's part. It's going to involve some hypothesis about what the alternative universe look like. And in coming up with that, Bates White, who, to my knowledge, is rather intimately familiar with -- with the calculations under the ELIADC and how that flows through the different mechanisms, suggested that there's concern that calculating that DR benefit to the -- to the penny will be difficult and it's possible that the results will be skewed in the direction

of overestimating the benefit rather than -- rather than underestimating.

So from that perspective, I think I was noting a similar type of concern that one doesn't want to credit through the DR -- an overestimate of the benefit that's brought, and so I think keeping some degree of benefit sharing -- I'm not saying that this necessarily is a significant sharing. I still think that PHP should be offered the opportunity to receive the cost benefits of its dispatch through the DR. It's just how to how to address the kind of things that Bates White's raised about the risk of overestimation.

Q. Thank you.

MS. MacADAM: Mr. Norwood, I will need to go to Mr. Bowman's evidence to evidence N-25, Exhibit N-25 for the next question.

And I'm looking for PDF page 12, if I may, which is -- I think it's the same document number, page 12, looking at line -- starting around line 11, where

it says, "For this reason".

BY MS. MacADAM:

Q. So just taking you to -- at this point. Mr. Bowman, in your evidence, you say at line 11 to 13:

> For this reason, crediting PHP with the full incremental savings as compared to the theoretical baseline of a CBL load risks excessively crediting PHP and harming other ATL customers.

And then you go on to discuss the past current issues with the calculation of CBL.

Can you elaborate on what would be the risk to ratepayers if NSPI did not accurately establish PHP's CBL and precision within the context of what you're saying there?

A. Yes. Mathematically, my understanding is that means the DR would lead to a credit to PHP that exceeds the benefit they brought to the system And my understanding of that credit is that it will be

added to the FAM and paid by the other customers. So if that credit is too large, the other customers will pay through the FAM rider.

Q. I'm just going to find my reference. One moment, please.

MS. MacADAM: Actually, the easiest way, Mr. Norwood, maybe to go back to the opening statement, if I may, because I have the reference for that. Exhibit N-44, and we're looking back at page 2.

And if we can pull it up just for above -- yeah. If we -- I'm just looking for above the number 3, the sentence just above it so folks -- and I can read it out.

BY MS. MacADAM:

Q. So in this, this is the last sentence before your recommendation number 3, which is shown on the screen, where it says:

> This added potential credit of the DR to PHP, unrelated to NSP supplies, further supports the

principle of benefit sharing with other ratepayers.

So I'm just back to the benefit sharing part here, but it's referenced to the wind and what the DR applies to.

Can you -- when we look at this and you refer to the despatch rider applying to both NSPI supplied resources as well as the wind. And this -- this language around this added potential credit, please, can you explain what you're referring to in terms of that added potential credit and give us an example?

A. Yes. In the overall costing framework for PHP, one starts with the idea that they establish their entitlement to the power to serve their plant through a mixture of Goose Harbour wind at around 500 gigawatt hours, but no firm capacity, and purchases from NSP's system at approximately 300 gigawatt hours and capacity up to 120 megawatts, in my submission. Having established that -- that entitlement to this base of power,

they then can be credited to the DR through shaping that power, and they can be credited to the DR for shaping all of that power, not just the 300 that they bought from NSP.

I'll say that's a bit unusual. Usually when people are talking about developing wind, there's a cost applied to it for shaping and firming in this place. In this case, they -- PHP can actually get a credit for effectively shaping and firming or shaping to match the system.

And that idea that not only is the Goose Harbour wind being shipped to PHP without line losses and the other things that people have talked about, but that PHP can shape that 500 gigawatt hours of its load and be -- receive a credit from other customers where that 500 gigawatt hours would never -- never even part of the regulated system, was never bought from NSP in the first place.

That -- that piece, I think, looks a little bit different than the other portion in the DR.

I'm not sure what to do with it. It's not something I've run into before. I still submit that the DR should be available to PHP on all 800 if they can create value. They should be able to get the DR for that. But I would just be extra cautious about overestimates where PHP is being credited more than the value they create when we're talking about power they didn't even share with other customers in the first place in the -- in purchasing from NSPI's assets.

Q. Those are all my questions. Thank you, Mr. Bowman.

MS. MacADAM: Thank you, Mr. Chair.

THE CHAIR: Thank you.

Port Hawkesbury Paper.

MR. MacDOUGALL: Good morning, Mr. Bowman.

Mr. Norwood, if you could pull up in 46, this was an extract that counsel for the Industrial Group had marked as an exhibit. Thank you.

If you could just go to the question and make it a little bolder here.

CROSS-EXAMINATION BY MR. MacDOUGALL

Q. So Mr. Bowman, are you familiar with the -- with this document that your counsel was looking at over the past couple of days?

A. Yes, I'm generally familiar with it. Yes.

Q. Okay. And it was stated that Port Hawkesbury Paper provided a request in the lead-up to the settlement discussions -- what was called the -- or the lead-up to the GRA, what was called a DR phase, that NSPI carry out certain modelling that PHP's firm load be bundled at eight megawatts at the 3 CP, the interruptible load will be modelled at actual PHP metered load at the time of NS Power's 3 CP, which was 65 megawtts for modelling purposes for this model, energy at 810 GWh and proposed billing determinants for the COSS should also be used for the BCF model as well; correct?

A. Yes.

Q. And are you familiar with the models that were filed in response to this?

A. Generally. Again, there were -- there was a lot of material that changed hands in that period, I'm sure you will remember, but I'm generally aware of the Cost-of-Service Study and the way that NSP was producing them for all the different scenarios that were thrown at them.

Q. Okay. So at this time, when NSPI asked for that -- when Nova Scotia Power asked for that to be done with respect to the -- sorry, when PHP asked for that to be done with respect to the interruptible load, it didn't indicate what credit to be applied for the interruptible load.

A. That's correct.

Q. Okay. And can you confirm that that model, when it was run by Nova Scotia Power, in fact used the interruptible credit that would apply to Port

Hawkesbury Paper, the $13.107 if they used their standard practice?

A. I can't confirm that, but I could find it quickly if we had the version of the model.

Q. Okay. That -- we have the version of the model.

A. Yeah.

The value of the interruptible credit in the model is reported at the bottom of table -- or Schedule 6, I believe it's called, and it links to an input that is done in input Tab 2, which I think is probably the last page in the entire Excel file.

Q.

A. And there's a cell there that they input that value in, but we could quickly confirm if it was $7 or 13.

Q. Yeah.

MR. MacDOUGALL: Mr. MacDuff is just going to send that to Mr. Norwood, Mr. Chair.

MR. BOWMAN: Or alternatively, you could look at the dollar value -- the total dollar value credited.

BY MR. MacDOUGALL:

Q. That's what I'm intending to do.

A. Yeah, at -- where it gives the row for the credit. So that's fine, too. Either of those will give us the answer.

MR. MacDOUGALL: So if we could go to Exhibit 6, Mr. Norwood.

Column C, line 354.

Mr. MacDuff just sent to you.

MR. MacDUFF: Yeah, it's an Excel spreadsheet.

BY MR. MacDOUGALL:

Q. Mr. Bowman, you appear to have that there. So while we're waiting for it to come up ---

A. I don't have that model. I have a different version of the model and they all use the same

template so I was just trying to ---

Q. No, thank you very much.

We'll wait to pull this up.

A. There were a lot of versions.

(SHORT PAUSE)

THE CHAIR: Not sure what's going on there, Mr. MacDougall. Maybe try sending it again, perhaps. I'm not sure if that'll help, but.

MR. MacDOUGALL: And maybe while we're doing that, I can ask some questions subject to check, and then we could check it later, once it's here.

THE CHAIR: Mr. Bowman. Is that acceptable?

MR. BOWMAN: Absolutely. Yeah.

BY MR. MacDOUGALL:

Q. Okay. So Mr. Boman, with reference to you saying the total -- total dollar value, can you take subject to check that the total dollar value in that model was actually the $9,539,000 that we were

talking about earlier that reflects a credit of 13.107, not a credit of 7.667.

MS. RUDDERHAM: Before he answers, I think I -- we would prefer if Mr. Bowman has the opportunity to actually look at the document. I don't know if you're able to extract that one schedule.

I mean, I was able to pull it up on my computer here.

UNIDENTIFIED SPEAKER: I have it here. I just forwarded it to. Mr. Bowman.

MS. RUDDERHAM: Okay.

MR. MacDOUGALL: If you have it there, you could show it to Mr. Bowman if we want to do it that way. But we can wait for the official record to use the right document.

MS. RUDDERHAM: You're okay if I just pass to show it to him?

MR. MacDOUGALL: Sure. Make sure it's the same document. James can confirm. Just show it to

James.

MR. MacDOUGALL: So we'll do this, Mr. Chair, but then we'll get the document brought up for purposes of the transcript and otherwise.

THE CHAIR: We may have to wait for Canada Post to deliver at this point in time.

BY MR. MacDOUGALL:

Q. So Mr. Bowman, if you look at Exhibit 6, column C, line 354, do you see a number there of $9,539,000?

A. Yes. And just for the purpose of the transcript, I would note it's in a file called "Settlement DR PHP4-01, Attachment 001.xls, and it is in Exhibit six, cell C354, and the value is 9539.

Q. Okay. So when Port Hawkesbury Paper asked NSP to respond to that model, in doing their response, they developed the credit the way they would do using their standard practice; correct?

Q. Yes.

Q. Okay. Are you aware that any models -- any of the models that were shared with you before the settlement agreement used anything other than the 9,,539,000?

A. I'm not aware that any did, but it's probably not something I looked at in in a lot of detail. But I would -- you know, I would think based on the structure and the model and the way the inputs work that the norm would be that they would be run with the $13 or $160 credit, and that would lead to nine, five.

Q. Great. Thank you very much.

A. I'm sorry. By that $9.5-ish million.

Q. Thank you.

THE CHAIR: Mr. MacDougall. I'm not sure if that's come through yet. Had you intended to mark that as an exhibit in this proceeding?

MR. MacDOUGALL: I guess we should mark the model as well, Mr. Chair. So it's the model that was

filed in response to the questions -- the question posed in Exhibit N-46.

THE CHAIR: That's Exhibit N-50.

EXHIBIT NO. N-50: Copy of Settlement DR PHP 4-01 Att 01

MR. MacDOUGALL: Thank you very much.

So just for the record, Mr. Chair, Mr. Norwood has received the same document from Mr. MacDuff.

BY MR. MacDOUGALL:

Q. And that's the reference that we were just looking at, right, Mr. Bowman?

A. I see it on the screen now. Yes.

Q. Okay. Thank you very much.

A. And for reference, you will see at the top that it refers to the input data tab. And if you were to go to those cells, one of those cells would be, I believe, $160, which is the $13 times 12.

Q. Correct. And that would -- from our discussion earlier today with the Consumer Advocate's witnesses, that's what would give you the 9539.

A. Correct.

Q. Correct. Thank you.

MR. MacDOUGALL: And Mr. Norwood, we had sent you an excerpt from Nova Scotia Power's 2026-2027 GRA Cost-of-Service Study document. Can we pull that document up?

Mr. Chair, the document is 29 pages. We're only going to actually refer to two pages of the document.

Yeah. That's it.

And if you could go to page 23.

I think you only have the two pages there, 23 and 24.

MS. RUDDERHAM: Sorry. Can we just clarify the matter number or the exhibit number.

MR. MacDOUGALL: Yeah, we're going to do all that.

So this document here is from matter M12451. It's Exhibit 9, which is Nova Scotia Power's Cost-

of-Service Study process document, Appendix 12A.

BY MR. MacDOUGALL:

Q. And at page 23, if we could go to page 23, under the heading "Proposed Maintenance of Status Quo" NSPI stated:

> Through the detailed stakeholder sessions, NS Power and stakeholders comprehensively reviewed each component of the current Cost-of-Service Study. Through this review, NS Power identified areas of interest to stakeholders and where stakeholders may have alternative proposed approaches to the treatment within COSS. NS Power has outlined these areas in the below sections and provided support for the Company's position that the maintenance of status quo is appropriate.

And you -- did you participate in any of those stakeholder sessions?

A. Mr. MacDougall, I'm not sure if this document is referring to the GRA settlement stakeholder sessions or the cost of service review stakeholder sessions, but in either case, I did

participate, yes.

Q. You did. It was the cost of service.

A. Yes.

Q. And if we could turn to page 24 under the heading of "Allocation of Demand Costs".

And just -- we're going to just read the first two paragraphs:

> Allocators are used to determine cost responsibility. As noted above, costs classified to demand are associated with the cost of providing required capacity to serve customers. For this reason, looking at the drivers of system peaks is the primary factor to consider when determining cost causation, which is one of the considerations that goes into the approach to allocating demand costs in a manner that reflects cost responsibility.
>
> The second factor that is looked at when determining the allocation of demand costs is volatility, which is generally controlled by looking at a number of system peaks rather than a single peak event. NS power currently utilizes a fixed 3 CP

> approach. NS Power as a winter peaking utility so it looks to the top system peak in each of the months of December, January and February, which are generally the coldest months in the province, determine its allocation of demand costs. NS Power investigated, several other potential approaches to this, but determined that the current approach continues to reflect cost causation while also balancing volatility and allocation of costs year over year by assessing cost causation across the three coldest months. This analysis conducted by NS Power is demonstrated by the data included in its response to DR-88.

Do you generally agree with those comments?

A. I agree with the first paragraph that set out that the principle is to attempt to reflect cost causation. I agree that they use a fixed 3 CP approach and that December, January, February are the coldest months of the year.

It goes on to say they investigated several other potential approaches and that NSP made a

determination that this is the best. It's not -- I'm not sure I can fully support that the 3 CP is the best, but it is the current method and it's been approved for use in this jurisdiction.

So I accept all of that.

Q. Yeah.

A. If you want me to go on a rant on 3 CP, I'm happy to do it, but that's a whole separate matter.

Q. No, just --

A. Yeah.

Q. -- just accepting this piece and it's in the cost of service and has been approved for this jurisdiction. That's fine.

MR. MacDOUGALL: If we could go to Exhibit N-28, page 11, which is the IG's response to PHP IRs.

And if we can go to 5(g). And if I can first read the question.

And go down to (g), Mr. Norwood, please.

BY MR. MacDOUGALL:

Q. And here it says:

> If PHP load is reliably dispatched down ahead of or during system peaks to preserve grid integrity, please explain why that operational response does not constitute a tangible capacity resource that avoids the need for incremental peaking capacity investments.

And if we could continue to page 13. And this is the second paragraph of your response to (g).

Right there. So your response here, you provided an example:

> Consider an LIIR customer or class who may have a process that operates poorly or uses relatively little power at very cold temperatures. This load may peak at 50 MW, but at the time of coincidence system peaks only operate at 30. The utility would plan its system for this customer to have a 30 MW load, but for this load to drop to zero (i.e. the Interruptible program) would contribute 30 MW to coincident peaks

because that is all that the customer can contribute based on their operating forecasts. The reason that the customer typically operates only 30 MW during system peaks, and not 50 MW at system peak times, is irrelevant. It may be a physical limitation or engineering or economic. The customer or class would have their own reasons that are not relevant to the system planners. Most important, it would not be appropriate to give this customer or class credit for 50 MW of interruptibility at the full value of avoided capacity as they did not avoid that capacity, they only avoided 30 MW. This is what is done for the LIIR in the Cost-of-Service Study.

So do you agree with -- do you continue to agree with that example? That -- that was an example you provided?

Q. Yes.

Q. Okay.

A. But I will say I'm not sure I fully answered the question, if that's where you're ---

Q. No, no. We're just going to stick

with the example.

A. That's fine. Yeah.

Q. I think the answer was sufficient.

So if we just stop there for a moment. Now, under Nova Scotia Power's Cost-of-Service Study that we just reviewed, demand costs would be allocated to this customer or class based on 30 megawatts; correct?

A. Correct.

Q. Not the 50.

And that's because 30MW is the amount of load forecast to be on the system at times of system peak.

A. Yes. The customer -- there's load diversity in the in the overall load and this customer only anticipates to have 30 megawatts on the system. They weren't paid for that. They weren't credited for that. They just operate at 30 at times of system peak, so that's all the costs that would be allocated to them.

Q. Perfect. And the so the

concomitant pieces, the customer would not be allocated demand costs based on the 50 megawatts.

A. Right.

Q. Correct? Okay.

And NS Power would plan its system assuming 30 megawatts of interruptible load ---

A. Exactly.

Q. --- not 50; correct?

A. Exactly. It starts with 30 in the planning. That's what I realized I didn't quite answer the question. In this case, it starts with 30 in the planning, and then it credits that 30 via an interruptible load adjustment to the planning number.

Q. Okay. And if the 30 megawatts used to allocate costs was interruptible but the customer's given an interruptible credit for a value lower than 30 megawatts, then the customer would not be getting the full value of the capacity they avoided; correct?

A. Correct.

Q. Okay. And the intention is to match the credit against the applicable allocated costs; correct?

A. Correct.

Q. Thank you.

Now, earlier today, you were having a discussion with one of my friends, and you said that there should be some IT credit. But what I understood from your specific evidence was that you stated that PHP should obtain little or no interruptible credit if it is on the DR rider. Is that correct?

Q. Yeah. I -- when preparing my evidence, I did not have data that would tell me what the anticipated load of PHP would be. We had lots of historical data, but we didn't have this idea of a detailed customer baseline. And so I was suggesting that NSP should be expected to create that and it would need to create that to run a proper Cost-of-Service Study, which it didn't do for the GRA. And that once it -- it did that, it would

apply the expected DR operation to that to come up with the peak.

If that peak left some interruptible load on the system, then -- then there would be a credit for that. But my -- and when I prepared my evidence, I had assumed that there would not be. If there were, it would receive a credit.

Q. Okay. Now, if we could go to Exhibit N-28, Industrial Group response to PH IR-1(a).

And if we go to page 4, the response.

And if we look at lines 11 and 12 here, it says, "At the above revised proposal on demand" -- this is your proposal, Mr. Bowman -- "120 MW, the same calculations lead to the credit being $907,000 per month."

Is that correct?

A. Yes.

Q. Okay. If we can go to page 5, lines 3-4.

And here you say, "Adjust DR" because

you're -- this was a question where you were asked to quantify to your best ability what all the changes that you proposed would yield. And here you say:

> Adjust DR reduced credits of up to 907,000 per month or up to 10.9 million in the extreme.

And the 10.9 million, my understanding is, you know, a credit for 120 megawatts at the 7.6 figure.

A. Yeah, 108 because -- or 112, sorry, because it ---

Q. I'm sorry, 112. Yes.

A. Something like that.

Q. Yes.

A. But these were -- like I couldn't -- as I noted the outset of this question, I can't rerun the Cost-of-Service Study that they -- that NSP has. But this was an attempt to ballpark it. And as we've gone through, the 57 megawatt interruptible credit gives approximately four something million, five -- four something million in -- or five something million, sorry,

in interruptible credit to PHP. We saw the five million-ish number.

Q. Yeah.

A. So when I was saying, well, what happens if you go to 120, I sort of doubled the demand.

Q. Right.

A. But in the process, I also doubled the IR credit. So now the difference between zero and 108 is that $10 million. And I think that's where the -- where the sort of ---

Q. Yeah.

A. --- the range of possible values in this proceeding vary.

Q. Zero -- between zero and 112; correct?

A. Yeah. Zero and 112. I'm sorry. Yes.

Q. No problem.

A. I'll keep making the same -- yeah.

Q. No, no, that's no problem at all.

But again, if we did that, if we went to the 112, your proposal, and we used the 7.6 figure, the credit that would be applicable would be $10.9 million; correct?

A. Yes.

Q. Okay.

A. If it was determined that -- that you go through the same steps I had set out, but you said there -- 120 megawatt load, there's a DR against that, but I still want to give an IR on everything. If you said the DR doesn't give me capacity, so I want to give an IR on everything, you would come out to this $11 million credit, correct.

Q. And doing the same thing that you said you did,, if you applied the 13.07 instead of the 7.638, could you take subject to check that the credit would be approximately $18.7 million?

A. I have it in front of me. Yes.

Q. There you go. Perfect.

A. I wrote it down as 19, but you're -- we're on the same page.

Q. That's right. That's perfect.

So if PHP -- if PHP was on the DR, we talked earlier with Mr. Mahmudov that it would be maybe roughly half of 7 to 11 million dollars in value that would accrue under the DR; correct?

A. Yeah. I think that number needs to be characterized. But yes, that -- that number has been quoted in the evidence. There's an IR, though, that supports it that has a lot more detail than that.

Q. Correct.

A. Yeah.

Q. And then we came to a generalization if you had the priority interruptible, it may be $6 million or maybe even as high as $10 million at the very highest point; correct?

Q. Yes.

Q. Okay. But if Port Hawkesbury Paper has the ability to get $18.7 million of credit against your proposed 112 -- or $10.9 million of credit, even at the lower 7.76 value, why would they stay on the DR where there's only a potential value of somewhere between 6 and 10 million dollars that wouldn't be known at the end of the year after having gone through all of the operational and commercial risks of the DR?

Why -- why would they do that if you were going to use your 112 and the credit applicable to that, why would they not just say, well, we'll just be an interruptible customer because the value proposition is greater?

A. Well, I couldn't speculate, Mr. MacDougall, but I'd note you said 6 to 10. The IR that supports the potential range of the DR actually establishes values as high as 17 and -- subject to their own performance. And of course, it gives them the opportunity to gain value from shaping their own wind that they

wouldn't have if they were just an IR customer.

So -- but I think any customer would have to consider those aspects and make a decision.

Q. Okay. But NSPI's evidence is that their estimated amount for 2027 was 7 to 11 million dollars and they assumed that the customer may only be able to achieve 50 percent of that.

A. Right. But if you go to Exhibit N-20, which was IR-16 from Synapse, the 7 to 11 is a 2027 number. The 2026 number was 8 to 13. I'm not sure why that is. And those are -- why it's larger. But those were P10 to P90 values. The actual upside that could be available when you go to the highest scenarios run were 12.5 million in 2027, up to 17 million in 2026.

Now, when questions were asked about those values, we were told all the data was lost in the cyber incident, so I'm not sure how to -- how to disentangle those.

Q. Yes.

A. But that's why I've always put a bit of an asterisk beside the 7 to 11 number.

Q. Okay. That's fine.

A. And that was Attachment 1, which is -- to IR-16 from Synapse.

Q. Thank you.

If we could turn to Exhibit N-28, your response to PHP IR-1(b). I think we may be in that.

And if we go -- could we go to the question first?

And here the question was:

> Provide the revised ELIAD tariff charges and credits if the Board were to adopt all seven of Mr. Bowman's recommendations.
> Correct?

Q. Yes.

Q. Okay. And if we go to page 5.

And starting at line 7, you noted:

> Because a number of the above estimates can only establish a range, it is not possible to set a

precise impact, but using the most extreme values in each case leads to a total cost allocation to PHP, net of DR, of $48.5 million.

And then if we can continue down:

Note that the allocation to the LIIR class is $79.2 million. Given PHP is slightly over 50% larger in capacity than the LI class (120 MW versus 77 MW) and slightly over 50% smaller in energy (305 gigawatt hours versus 695 gigawatt hours) but is intended to be given benefits for their load shaping, the outcome is generally consistent with the intent that PHP can capture savings from its load shaping activities and yet is still intended to have a reasonable ATL rate.

Correct?

A. Yes.

Q. So here you show a cost allocation to PHP of $48.5 million on a load of 305 GWh; correct?

A. On a on a very low load factor load of 305, yeah.

Q. Three hundred and five (305). Correct.

And I understand that this is using what you refer to as the most extreme values, but this is an estimate you prepared assuming your recommendations were all accepted; correct?

A. Yes. Yeah. That was -- like it's obviously difficult because you have to make assumptions, but these -- this was an estimate I prepared, yes.

Q. Yeah. And if all of your recommendations were accepted, it would lead to PHP being responsible for $48.5 million as against NSPI's application of approximately $38.1 million. Is that correct?

A. I think we're talking different numbers because there's -- the DR is involved in these.

Q. Okay. Can we go to page 4, line 29.

A. Are we ---

Q. And it says, "per NSP application 38.1 million".

So you start it with NSPI's application

and then you made your adjustment.

A. Correct, but-- yeah. This is where we get into the confusion, Mr. MacDougall, that NSPI's application, that's the cost of service allocation.

Q. Correct.

A. It doesn't have the DR credit in it, but it also doesn't have the adjustment for the amounts that will be collected from the FAM for changing the cost of service back to a CBL level.

So I use that as the input. I'm just cautious as to whether that is the final ---

Q. Okay.

A. --- final word on it.

Q. But if there were -- if there were DR credits, that would lower that ---

A. That's right.

Q. --- correct?

Okay. That's fine.

So the difference would be something

around 38.1 million, possibly lower, but against your ultimate number of 48.5 million.

A. Yes.

Q. Okay. And now if we simply divide the cost by the load, the 38.5 million divided by the 305 GWH, would you accept subject to check that that results in a dollar per megawatt rate of approximately $159 per megawatt hour?

A. Yes, because you're dividing by an energy rate on a low load factor customer. Yes.

Q. Correct.

A. It leads to a high average energy rate. That's what happens with low load factors.

Q. And if I do the same math for the large industrial class and divide the allocation of 72.9 million by their load of 69 695 GWH, this results in a dollar per megawatt rate of approximately $104.90 per megawatt hour. Do you agree with that subject to check?

A. Yes. That's a high load factor

customer. Yes. or group of customers.

Q. Okay. Now, that assumes when you set extreme values that PHP actually received $11 million in demand credit.

A. Yes. And it assumes that they get no IR, even though there could be up to 11 million, depending on how this Board decided;.

Q. Correct.

But if -- for example, let's say that PHP received the 5.5 million, 50 percent of $11 million, which is what NSP said they were expected to do, then the 48.5 million goes actually to 54 million; correct?

The other 5.5 would be added on as a cost.

A. Yes.

Q. And if we divide that 54 million by 305 GOH, can you take subject to check that we'd be paying as much as $177 per megawatt hour?

A. Yes.

Q. Okay. And of course, if you use the lower band of $3.5 million, that would go up even higher; correct?

A. Yeah. Again, the point is there were extreme assumptions in both directions so if you mitigated one of those and not the others, the value would go up.

Q. Okay. But on your extreme value example of what the impacts could be, those are the dollar figures that would fall out of that on a megawatt hour basis.

A. Those are the dollar values that would fall out if the DR was lower and if NSP's assessment of a CBL did not lead to a conclusion there should be an IRR after application of the dispatchable rider load benefit.

Q. Correct. Okay. That's perfect.

MR. MacDOUGALL: Now, Mr. Norwood, if we could go to Exhibit N-25, which is Mr. Bowman's

evidence. And if we could go to page 4.

Yeah. And right there is fine.

BY MR.MacDOUGALL:

Q. Now, you covered some of this with my friend earlier. I want to still go through it and ask a couple of different questions than she did.

So recommendation 2 is:

> The rights provided NSP in the ELID Dispatchable Rider should include practical control of dispatch at times when the system has small reserve margins or supply constraints. As proposed, the purported control only arises from general economic price signals.

Correct?

A. Yes.

Q. Can you indicate -- I think you did this morning, but just to be sure -- what you mean by "practical control of dispatch"?

A. Yes. I found it difficult to put the appropriate words around this to get across the concept

and so I appreciate the opportunity to clarify.

But in general, there is a set of descriptions of the DR that is used that at times says PHP can do whatever it wants and at other times says, oh, no, this is dispatchable like a generator and NSP has control and, of course, PHP will generally follow and listen.

And I found that to be relatively inconsistent evidence and I thought that it's important to find a way that it is communicated, whether that's through concepts and words or potentially through some dollar values, if it -- if it came to that when the DR really matters, which hours. You know, in March, it's probably not that big a deal, but there are hours where it matters much more. And I wanted to make sure that we didn't lose the idea that there's an opportunity for NSP and PHP to communicate which hours make a big difference and which are lesser priority.

I'll say based on the evidence I heard of PHP earlier or yesterday, I do think they -- it's clear

they take the dispatch information from NSP quite seriously and so it may even be that that this is unnecessary, but I was worried about the, rather, I'll say almost -- almost flippant language about, well, they don't have to listen. So I was trying to find a way to communicate that it should be a way of ensuring that they understand when things -- when price differences really matter.

Q. Okay. But that -- you wouldn't be suggesting that they have the right to mandate the customer to drop its load.

A. No, that's -- that's part of the interruptibility provision, not the DR, correct.

Q. Okay. So -- but -- and you said earlier that the interruptible provision could have little or no value depending on what was -- what was on at the time; correct?

Q. Yeah. Yes.

Q. But in these time periods, what would be on at the time if -- and if PHP was being

incentive to go down further would likely be a drop to a low level; correct?

A. Yeah. That's what the evidence seems to show. Yes.

Q. And then that would impact the interruptible credit that could be applied to Port Hawkesbury Paper in your proposal.

A. Right. Just like that example we gave of the 50 megawatt customer who's actually 30 megawatt at peak. They went from 50 to 30 for their own reasons without being paid for it. They still have 30 on the system that's interruptible.

In PHP's case, there we call them 120 but, really, remember they could be up at 160, but they're -- they're at a load where they're already incented to go to a lower level. Not for their own reasons happen to be operating at 30, they're incented to go down to that level and then you would look at that to determine the interruptibility, in my submission.

Q. Yeah. So essentially, if there was a right to try to have more practical control of dispatch by telling a customer, you know, we're having problems on the system, we'd really like you to go down, at the same time that would be telling the customer, we want you to go down to a level that you're now likely to get no interruptible credit for.

A. Well, I was thinking more like we're -- we're having to dispatch our highest cost units or import power at very high costs right now so if you're going to respond to a DR at some point or blow off a suggestion about an operating mode, this might not be the best time to do it because it's -- the cost implications are higher right now.

Q. Okay. So you didn't -- you didn't -- aren’t proposing practical control of dispatch in relation to reliability concerns on the system.

Q. No, I'm at the sort of, you know, as we've gone over, economic concerns and higher prices

tend to coincide with higher loads and less -- less reserves on the system. But the idea is to communicate which of those -- which of those hours and which of those operating modes are being communicated out of relatively lower value and which are of more significant value.

Q. And this practical control of dispatch or information sharing, whatever you may call it, would happen in all 8,760 hours of the year, not just the times of reliability issues.

A. Yeah, I think -- I don't think it would happen all 8,760. The whole point is to say that of the 8,760, probably 8,000 of them don't make that much of a difference. Probably most of the value arises in a much smaller subset. And having a way that that operating procedures conveys which of those really do make more of a difference to the value that could be attributed to the DR or the units that be kept offline, finding a way to emphasise that -- that priority or higher value in the communication.

Q. And yesterday, I think when Mr. Locke said that he wasn't getting price signals, he was -- he knew some of the generation, what generation was potentially on the system, but not a specific price signal, your suggestion is that the utility should probably give better price signals at the time?

A. Give better information, yeah. This is an hour that really matters. That's exactly the point. Yeah.

Q. Including -- including pricing.

A. Yeah. No, I think. Mr. -- it might have been Mr. Willett or whatever who testified that sometimes pricing is hard because it depends on, you know, factors like hedging and other things.

But yeah, indications of which -- they know which hours are -- matter and the pricing is generally higher. And so yes, I think it would be that -- that type of information. Yes.

Q. Okay. Thank you.

A. Not committed prices, though. That's my ---

MR. MacDOUGALL: Could we pull up Exhibit N-9? . This is Nova Scotia Power's responses to SBA IR-4(f).

And if we could go to the top of page 15.

BY MR. MacDOUGALL:

Q. And this IR asked NS Power to confirm if the DR credit is purely an energy-based valuation and does not include reliability or capacity cost avoidance already captured in the interruption and priority credits. "If not, what avoided costs are included beyond energy".

And then if we go to page 16 in response to that, at (f) it says, "Confirmed" and also refers to Synapse IR-14; correct?

A. Yes, I see that.

Q. Okay.

MR. MacDOUGALL: So Mr. Norwood, if we could pull up Exhibit N-10, which is NSPI's response to Synapse IR-14.

And if we could go to IR-14, I think it's at the bottom of page 38. And here we see at (c) and (d) at the bottom.

And then I'm going to want to scroll over to the next page when we get to it. Mr. Norwood.

BY MR. MacDOUGALL:

Q.

As provided in Parts (a) and (b), while there's likely to be a high level of coincidence during periods of tight system conditions, the PHP load will be dispatched down or interrupted or held as operating reserve. The two services are distinct, and PHP is being compensated for two separate value streams, IR for planning relief (i.e. the avoided cost of building new generation) and DR for operational cost relief (i.e. the avoidance of high real time marginal costs). The DR is calculated based on PHP's actual load compared to a base load shape on an hourly basis.

The IR is a credit planning mechanism and not paid for on an hourly basis.

So there's no capacity or demand costs that PHP will be credited for as part of the dispatchability rider; correct?

A. I see that text. I think NSP is incorrect in their statement here because of the issue I addressed earlier where they sort of split the -- split the difference, split the baby in half. The -- if NSP wants to say that PHP's load is 65, it is giving a credit for DR through the Cost-of-Service Study and not having PHP pay for the full peak it would have applied before the DR. So it -- NSP seems to be giving half credit through the cost of service where you go from the expected load down to 65, and then the remainder through the IR, where you then go from 65 down to eight. And so I think -- I read these responses, but they don't they don't accord with me with what I see in the numbers.

Q. Okay. But they're two different

services, though. The value proposition of the DR is to reduce energy costs and get a credit for that, but you don't have any demand credit provided under the DR; correct?

A. That is correct. There is no mathematical demand credit provided under the IR, but NSP does, in effect, give partial credit by adjusting the load down in the cost of service.

If the intent was to say, I want to start with the CBL and then hand over two sets of payments to PHP or two sets of credits, one that's DR for all of the load adjustment, and one that's IR for all of the interruptible load, then you would start with a number like I started with, 120, give a full DR credit and give 112 megawatts of IR credit.

Instead, NSP sort of goes halfway and -- in doing what they do.

Q. But the 120 -- what you've done with the 120 is say, because they're supposed to be a CBL

for the DR and it was said to be at a high load figure, you use the 120 figure; correct?

As if that 120 is the three winter coincident peak figure.

A. But that's what a high load factor customer would tend to operate at. We know they can be up to 160, but a high load factor customer consuming 800 gigawatt hours would have to operate close to 100 megawatts just to get 800 gigawatt hours delivered over 8,760 hours. There would be some variability. They're not 100 percent load factor. And so that the typical operating mode would be in that range of 100 to 120. That's what I used.

Q. Okay. We're going to get to the numbers.

A. Okay.

Q. So your view is the typical operating load would be 120.

A. The typical operating load would be in that OM 5 to 6 but for the DR. And that would be in

that range of 100 to 120.

Q. Okay. We'll go through those numbers in a little bit.

A. Yeah. But if you were to do that and if you were to say, I do intend to give a credit for it, I'm not considering the DR to be just a load diversity benefit, the DR is only an energy benefit and there's no capacity in it at all. So I do want to give them a capacity benefit. Then you would have an IR on the -- on the full amount up to 112.

Q. And there's no capacity credit in NSPI's proposal except with respect to the interruptible rider; correct?

A. No, that's not correct. That's -- that's my point.

NSP is doing a mish mash of credits by adjusting the load down to 65 in the first instance. PHP would not be expected to operate at 65 but for the DR. So they're getting to 65 by applying the DR, which is a

capacity related credit.

Because of the DR, they're letting them have a historical load or whatever other rationale leads to 65 as the cost of service value for PHP. It wouldn't be 65 but for DR. That's what we've heard.

Q. What wouldn't be 65? Their load at 3 CP?

A. Correct.

Q. But their load at 3 CP wouldn't be 120. We haven't heard any evidence that their load at 3 CP would be 120.

A. I think my understanding is that's exactly what the evidence says.

Q. Where does the evidence say that?

A. Because PHP is an operating industrial customer who would operate at a high load factor, consuming 800-ish gigawatt hours. To consume 800 gigawatt hours as a high load factor industrial customer, you would tend to operate -- you would have an average load

of around --

Q. Correct.

A. -- 100 megawatt -- around 95 megawatts ---

Q. An average load.

A. And that average load, because you're a high load factor customer, would have periods where you're down and periods where you're operating somewhat higher than that. The priority OM modes, we heard, were OM 5 and 6, and those lead to loads in that range, 100 to 120. Most days they would be operating that way ---

Q. But ---

A. --- in order to get 800 gigawatt hours consumed. That's the only way you can get 800 gigawatt hours consumed.

Q. Except you don't -- they don't have to run at 120. They could run at 160, they could run at a lower number. The 120 is the average load for the

year; correct?

Q. The 120 is -- no. The 120 is higher than average load for the year because there are periods where it's lower than that. And this is addressed in one of the IRS. I'm happy to go---

Q. Yeah, where there's cut-outs.

A. But the -- but the 160 -- it could be as high as 160, but I don't know why one would assume that they're at a downtime during a 3 CP. A high load factor customer is -- an industrial customer tends to operate throughout most hours of the year.

Q. **E**ven if those were anticipated to be high 3 CP hours.

A. Most industrial customers are operating throughout the year. That's what we keep hearing. They're a high load factor customer. That keeps being repeated.

Q. No, I don't know that we keep hearing that. What we hear is that to do the CBL, NSPI has

assumed that Port Hawkesbury Paper would be a high load factor customer for the purposes of the CBL.

A. Port Hawkesbury Paper said the same thing. They said, absent the DR, they would run at a high load factor and keep their machines ---

Q. Correct.

A. --- operating as many hours of the year as they can because turning them on and off causes thermal stresses and mechanical issues and a bunch of other things, which is exactly ---

Q. Right.

A. --- my experience with industrial customers.

Q. They would run flat, but not necessarily ---

A. Right flat. Yeah, same thing. That's what high load factor means.

Q. Yeah, but they would try to -- they would try to to not meet the winter 3 CPs running at

that level.

A. Well, you're saying that any industrial customer would try to project the day that's going to be the coldest day and try to cut their load on that day to ---

Q. When they have ---

A. --- retain the CPs?

Q. When they -- not to gain them. When they have -- when they have price signals, they would try to do that, sure. Why would you -- why would you not?

A. But we're saying absent the DR, they wouldn't have price signals. They would -- they would have a regular high load factor, flat load like any other industrial customer.

Q. I know, but -- but you're not proposing that they be absent the DR. You're proposing that there be a DR.

That's what I'm saying. You propose -- you propose a DR, and then you propose that the credit be

120, not the number that they'll actually be at on the -- on the 3 CPs.

If they're on a DR, their 3 CP will not be 120. You start with the CBL instead of starting with developing a tariff that they might be on. So once you have the DR, then you know they're going to be down in those time periods so you can't take their average load when they're on a DR rate and apply it and say their average load, if they run flat, is 120 megawatts, but they're not running flat because they have a DR, but I'm still going to have the 3 CP at 120.

That's what you're proposing. That's your ---

MS. RUDDERHAM: Mr. Chair, I just want to flag that there's a lot of evidence coming from counsel, and it's not abundantly clear where the questions are, where they end, so I would ask that he rephrase and -- and asked a question to the witness.

MR. MacDOUGALL: I don't think I'm

providing evidence, Mr. Chair. I'm just providing the facts that you need to do to actually answer the question.

I'm in your hands if there's an issue.

THE CHAIR: Yeah. I mean, there was -- there was a -- it seemed to be more of a debate back and forth. But if so, if you could focus more on questions, that would be helpful.

MR. MacDOUGALL: Okay.

BY MR. MacDOUGALL:

Q. So Mr. Bowman, your proposal -- you said in your proposal that Port Hawkesbury Paper should be on the DR. You think it's useful if they're on the DR, and they should be given the opportunity to be on the DR; correct?

A. Yes.

Q. Okay. So if they're on the DR, isn't the evidence clear that it's likely they will be down at a lower load during the winter 3 CP?

A. Yes, we are -- what that lower

load is, though, is highly uncertain. But yes, it is likely they'll be at a lower load at 3 CP.

Q. Well, we have we have historic data of what that lower load might be. I think even this morning you said it could be as low as nine megawatts based on the recent information.

A. That ---

Q. We do have that historic.

A. That's what I mean about uncertainty. We have a number of 65 from two -- two years' average. We have a number of 28, although I think that includes a data error. We have a number that's closer to 11 if you correct that data error. So it's very unstable.

They would be at a lower load. What lower load is uncertain, I think is what I said.

Q. No, but the methodology isn't.

We went through -- did you listen when we went through with Nova Scotia Power the methodology that they used to create the 2022 and 2023 numbers?

A. I'm not sure I --to create the 65?

Q. Correct.

A. I understood that the 65 comes from a historical study that PHP has said is not relevant any more and otherwise comes from a two-year average of 3 CPs from 2022 and 2023.

Q. Yeah. So it comes from a two-year average of 2024 and 2025 -- 2022 and 2023.

A. Right. But if you look at that average, it's actually highly unstable. And 2024 and 2025 lead to very different values.

So that's my point. is they will be lower, but we are -- we are quite uncertain as to what lower level they will be at.

Q. But the methodology that was done for the 2024-2025 was the same methodology that NSPI took to develop the 65 megawatts.

A. Yes, it took the 3 CP hours and took the numbers, and that's the number that reported 28

but we think is probably lower.

Q. Okay. So if we're on the DR, we'll be down at one of those numbers or a number like that, yet your view is, while being on the DR and being down in the 3 CPs, that you should apply 120 megawatts as if we were 120 megawatts on the winter 3 CP but we won't be 120 megawatts on the winter 3 CP if we're brought down by the utility, will we?

A. Right. But I think we're talking two different things.

The question you took me to on the page is, does the DR give capacity credit? Does it give capacity benefits?

And my answer was under NSP's approach, it does give capacity benefits because it does not charge PHP in future for capacity it avoided in the past due to the DR. It would have been higher, but because of the DR it was lower. Therefore, there's a DR reduction in the past which gets carried forward so there's a capacity

credit associated with the DR under NSP's approach, whether you end up at 65 or eight or whatever.

That's why I was saying I disagreed with the text on the page.

Q. No, but I'm talking about your approach, Mr. Bowman.

A. Yeah.

Q. Your approach is that that Port Hawkesbury Paper should get a DR and should be credited for that DR; correct?

A. Correct.

Q. Okay. And that DR would operate in the winter 3 CP months to likely bring Port Hawkesbury's load down.

A. Right. It would bring low diversity to the system.

Q. And likely bring its load down during the winter 3 CPs.

A. Correct. That's what the low

diversity does.

Q. But your proposal for what the winter 3 CP should be is 120 megawatts because that's the average load. But we don't -- we wouldn't -- why would -- how can you possibly have an average load that apply also as the winter 3 CP when your proposal indicates that during the winter 3 CP Port Hawkesbury Paper is likely to be much lower than 120 megawatts?

A. Because it's not because it's the average. It's because that's the expected load but for a DR.

Q. The expected load based on the average load over the year.

A. No, the average load over the year would be 800 gigawatt hours over 8,760 hours, which would be somewhere around 90-ish, 95-ish megawatts. I'm doing that math in my head, but 800 over 8,760.

The actual operation of a high load factor customer who's consuming 800 gigawatt hours would

likely be made up of some downtime load and some operating load, and that operating load would be as flat as possible. That was PHP's evidence and that's what's shown in the operating modes where they have a preference for those middle ranges.

That's what a high load factor customer would tend to operate like. They'd have some hours where they're down for maintenance and other things, and otherwise they would tend to flatten their load as much as possible. And that would lead to a peak somewhere or a load, a peak, somewhere in the range of 100 to 120 megawatts when they're up and running.

So the only question left is, would those 3 CP hours be hours where they're up and running, or would they be periods where they're down for taking maintenance? And given that the vast majority of the hours of the year would be up and running hours, I would take the assumption that they're up and running at those times. And that's why there would be a 3 CP.

Q. Even if they're on the DR.

A. Absent the DR. We're talking about -- we're talking in circles. We're talking absent the DR, they would be around 100 to 120M megawatts is what I'm asserting. And I think the evidence supports that.

Then you apply the DR and they get the -- and NSP pays them for the credit of shifting their load around and buys that load diversity. The only question that's left is should they be paid for the capacity that comes with that load diversity benefit or not.

And I was saying that based on the fact that they're paid to bring that load diversity, unlike the customer who was 50 and tended to be at 30, these guys, they don't -- that customer isn't -- isn't paid for that. That customer doesn't have a program for that. PHP has a program where other customers pay them to go from that expected 100 to 120 level down to something lower. And as a result of that, the only question left is, has that in effect yielded the load diversity, or do you still need to

have an IR that pays them for that capacity that we no longer think will be there because they have a DR.

Q. Okay. Thank you for that, Mr. Bowman.

I'm going to just try in very short form one more time.

Your proposal includes a DR.

A. Correct.

Q. Okay. And it includes that -- it includes the DR and it would assume that in periods of tight capacity supply or any supply, as noted in the record, they usually are brought down or they're requested to be brought down.

A. Correct.

Q. Correct.

So in those 3 CP hours, they would likely be at a low level.

A. Correct.

Q. Correct.

So because of that, you can't then, at the same time, say they'll be at 120 megawatts in that same hour; correct?

A. They -- they won't be at 120 after application of the DR.

Q. They won't --0

A. The CBL will still be 100 to 120 type of range.

Q. Okay. The CBL will be that, but that -- then you're -- are you agreeing that the CBL will be that, but they won't be at that level during the 3 CPs?

A. Correct.

Q. Okay. Thank you.

A. Yeah. No, I think that -- I didn't think that was in dispute.

Q. Thank you.

THE CHAIR: Mr. MacDougall. Just in terms of timing ---

MR. MacDOUGALL: Now would be good.

THE CHAIR: Good time for our lunch break?

MR. MacDOUGALL: Yeah.

THE CHAIR: Okay. Well, thank you for that.

So it's 20 to 1:00. We'll come back at 20 to 2:00.

--- Upon recessing at 12:40 p.m.

--- Upon resuming

THE CHAIR: Okay. Welcome back, everyone.

Mr. MacDougall, whenever you're ready.

PATRICK BOWMAN, Resumed

MR. MacDOUGALL: Thank you, Mr. Chair.

CROSS-EXAMINATION BY MR. MacDOUGALL (cont'd)

Q. Mr. Bowman, you made reference earlier to saying that PHP at a flat load would need to run at 120 megawatts. I think you then made reference later on to 99, but just to go through a few of the numbers, could

you, subject to check, take that 120 megawatts at 8,760 hours would generate 1,051,000 megawatt hours?

A. Yes.

Q. Okay. And to actually get the 810,000 megawatt hours, if you divide that by 8,760, that's approximately 92 megawatts.

A. Yes.

Q. And was that the number -- I think you said 99. You were doing rough math or whatever. Is that what you were referring to?

A. Yeah, I was in the 90s, trying, in my head, to do 800 gigawatt hours over 8,760 hours.

Q. Sure.

A. But in my evidence, I did note that 120 megawatts for 800 gigawatt hours is approximately a 76 percent load factor, which would be considered a high load factor.

Q. Yeah. But they don't need 100 -- PHP doesn't need 120 megawatts if they were going to

generate 810,000 megawatt hours; correct?

A. Not if they could run absolutely flat. Correct.

Q. Correct. Okay.

And PHP's evidence is that their forecast should be adjusted, and they've proposed a forecast of 774,000 megawatt hours; correct?

A. I can't recall if that's exactly the number, but they do suggest it should be adjusted, correct.

Q. Subject to check.

A. Yeah.

Q. Okay.

MR. MacDOUGALL: Now, Mr. Norwood, if we could pull up Exhibit N-25, that's Mr. Bowman's direct evidence. And if we could go to page 14.

And I'm going to look at line 16.

BY MR. MacDOUGALL:

Q. So here, Mr. Bowman, you say at

the end of line 16:

> Since PHP's expected usage after the DR is applied would yield very little load that would likely be available to NSPI to interrupt.
>
> Correct?

A. Yes.

Q. Okay. Now, if PHP were to forego the DR aspect of the ELID, not adopt the DR rider, then PHP's load would not necessarily yield very little load that would likely be available to NSP to interrupt; correct?

A. Correct.

Q. Okay. And if there was no DR, there would be no mechanism for NSP to call on PHP to reduce its load in high cost periods unless it led to a capacity constraint that allowed them to call on PHP under the interruptible rider after being held as operating reserve.

A. Correct?

Q. Okay. So PHP would generally operate like other interruptible customers throughout the year, and any increased fuel costs, such as the cost of CTs, required to run the whole system load, including PHP, would be shared by all customers; correct?

A. Well, the way I understand the cost of service is intended to run, that fuel cost is currently and is going to be paid by other customers. If there's a benefit from PHP shifting its load, it will be allocated 100 percent to PHP, which I've said I take no issue with. So I don't think that added fuel cost is a downside to other customers the way the rate has been structured.

Q. Well, no, but if we weren't on the rate -- if we weren't on the DR, PHP would pay average fuel costs of the system, correct?

A. Correct.

Q. Okay. And those average fuel costs could be higher for the system as a whole than if PHP

reduced its load to lower the average fuel cost.

A. Well, it's -- when you use the word higher, the question is, is sort of that higher than what? That higher number that you're talking about is exactly what NSP proposes other customers pay is the higher number.

Q. Okay.

A. To the extent PHP can reduce the load, it gets the credit. And as I said, I don't take any issue with that.

Q. Okay. Thank you.

Now, your recommendation number 5, maybe we can go to that.

MR. MacDOUGALL: It's page 4, Mr. Norwood.

BY MR. MacDOUGALL:

Q. And essentially, your recommendation is to provide no priority interruptibility credit, correct?

A. Correct.

Q. So in that case, PHB would not be priority Interruptible.

A. Correct.

Q. Okay. And we heard Mr. Stanford say last week that absent there being priority interruptibility for PHP, all operating reserve customers, including PHP, would go into an interruption rotation after the LIIR customers without telemetry and control?

A. Correct.

Q. Okay. So if the operating reserve customers with telemetry and control were required to be called upon, PHP would be called upon in a rotating manner with those customers.

A. That's my understanding, correct?

Q. Okay.

BY MR. MacDOUGALL: And if we could now pull up Exhibit N-1, Mr. Norwood. And that's the -- NSPI's evidence.

And I'd like to go to Attachment 1, which is the ELID proposed tariff.

It's page 5 I'd like to go to.

BY MR. MacDOUGALL:

Q. So there you see that's the tariff -- the proposed extra large industrial dispatchable tariff, Mr. Bowman.

A. Yes.

Q. And if we can go to page 5 of -- okay. We're already there.

Did you review this rider?

A. I believe I reviewed it when the application was first filed. I haven't gone back to look at it recently.

Q. Okay. And now if we can go to page 6. And if we can scroll down to item 6.

And here item 6 says that interruption is limited to 16 hours per day and five days per week to a maximum o30 percent of the hours per month and 15 percent

of the hours in the year. Do you see that?

A. Yes.

Q. And in particular, it says to a maximum of 30 percent of the hours per month.

A. It does say that. Yes.

Q. And are you aware of how many hours per month PHP has been brought down by NSP -- its load level has been brought down in recent winter months under the ADC?

A. No, only from the -- I'm only aware from the data that was provided of the hourly loads, but I didn't go through and analyze how much they've been brought down.

Q. Okay. And I'm probably going to come back to that --

A. That's fine.

Q. -- when we go through another information response.

MR. MacDOUGALL: And now if we could go

back to Mr. Bowman's evidence, Exhibit N-25. And if we could go to page 9,and just starting at line 10.

BY MR. MacDOUGALL:

Q. Now, this says:

> NSP has not provided a specific CBL demand load but has provided the PHP average operating load in response to information requests noting PHP's average load is a confidential value, but is approximately 15 times the 8MW figure, which would yield 120 MW. The standard running load values for 2023, 2024 and 2025 are provided in confidential filings and do not contest this range.

So that's a part of your evidence, right, Mr. Bowman?

A. Correct.

Q. Okay. Now, with respect to the 120 megawatt figure. If we can look at footnote 14, just scroll down the page. You see that's the footnote number next to 15 times eight.

A. Yes.

Q. If we could go to the footnote and

you refer in footnote 15 to Exhibit N-5, PDF page 204, correct?

A. Yes.

Q. Okay. And N-5 is NSPI's response to CA information requests.

MR. MacDOUGALL: So, Mr. Norwood, if we could bring up Exhibit N-5e.

And your reference was to page 204.

If we can go -- in N-5, f we can go to PDF page 201. We see that this is CA IR-9.

BY MR. MacDOUGALL:

Q. That's where the questions start.

A. I'm with you.

Q. Okay.

MR. MacDOUGALL: And if we go to page 204 of the PDF, Mr. Norwood.

BY MR. MacDOUGALL:

Q. The second bullet, it refers to PHP's average load being approximately, and that's blanked

out. But following the blanking out, it actually said 15 times the eight megawatt figure.

So that's where that's where you got your number from.

A. That was the only non-confidential source I could find to come up with a number.

Q. Okay. And this was NSPI's data. This is NSPI's position in response to the CA IRs.

A. It is NSPI's response. I don't know whose data it is.

Q. Okay. If we could -- okay.

But it's NSPI's response.

A. Yes.

Q. Okay. Now, if we can go back to your evidence, page N-25. And if we could go to page 9 and if we can look at line 12.

And then you say:

> The standard CBL running load values for '23, '24 and '25 are also provided in confidential filings and

do not contest this range.

Do you see that?

A. Yes.

Q. Okay. And the footnote there is footnote 15. And if we could go to footnote 15.

And here it says the reference for that statement was Exhibit N-10, which is NSPI responses to Synapse IRs.

A. Yes.

Q. Correct? Okay.

MR. MacDOUGALL: So Mr. Norwood, if we could go now to Exhibit N-10. And if we can go to IR-24, which is PDF page 66.

BY MR. MacDOUGALL:

Q. And if we go down to (e), you'll see here it says:

> Please provide in an Excel workbook the calculation of pH high load factor customer profile for '23, '24 and '25.

And then if we go to page 68, we'll see the response there. "Please refer to confidential Attachment 1."

A. Correct.

Q. And that that's what you referred to when you looked through confidential Attachment 1 to make the statement that you did; correct?

A. Yes. That, and the operating modes as I mentioned earlier, but primarily it was this source.

Q. Okay.

MR. MacDOUGALL: That confidential attachment, Mr. Chair, was solely PHP data. And again, for the purposes of trying to stay out of confidential session, PHP has waived the confidentiality and we have sent the -- a document with some revisions placed into it that we're going to go through to Mr. Norwood.

THE CHAIR: Thank you.

MR. MacDOUGALL: And if you could bring

up that document, Mr. Norwood, it's three pages referring to ELID tariff Synapse IR-24.

MS. RUDDERHAM: Apologies, Mr. Chair. Could we get a copy of the new exhibit and perhaps provide one to --

MR. MacDOUGALL: It's up on the screen. We're putting up what was non-confidential and the yellow material is material that we've added that we're going to run through with Mr. Norton -- with Mr. Bowman.

MS. RUDDERHAM: Could we keep a copy of this so we can follow along?

MR. MacDOUGALL: Absolutely. I'm just saying it's on the screen.

MS. RUDDERHAM: Thank you.

MR. MacDOUGALL: I'll follow along on the screen.

BY MR. MacDOUGALL:

Q. So Mr. Norwood, if you look at --

sorry. I'm going now to you, Mr. Bowman. Maybe Mr. Norwood would have been able to give a good answer. I'm not sure.

If we look at this, and if you could make it a little bit bigger.

And here there's a number that says average running load 130 megawatts for 2023.

MR. MacDOUGALL: Then if we can go to the next page, Mr. Norwood.

125 for 2024.

And if we can go to the next page, 128 for 2025.

BY MR. MacDOUGALL:

Q. And my understanding is that it's those numbers you relied on to say that the CBL running loads do not contest the range of the 15 times eight or the 120.

A. Correct?

Q. Okay. And what did you mean do

not contest the range? Because I thought the reference was just to 15 times eight, whatever that number was, 120.

A. Well, I just wanted to -- all I meant is that they're in the same order of magnitude.

Q. Okay.

A. That's all.

Q. Same order of magnitude.

A. Yeah.

Q. And what do you what did you mean by do not contest?

A. They didn't -- they were not different than I was.

Q. Okay. And ---

A. They're actually higher, but that's not the...

Q. Yeah, they're slightly higher.

A. Yeah.

Q. Yeah. And you're aware that this response is totally based on PHP forecast numbers. These

are not historic actual figures.

A. I don't recall if I was aware of that, but if you want to -- but if that's what you -- PHP's evidence is, I don't have any issue with that.

Q. Okay. Let's go to Exhibit N-4, NSPI's response to Bates White IR-6.

MR. MacDOUGALL: The confidential version, Mr. Norwood.

With respect to this as well, Mr. Chair, this is PHP's information and they're waiving the confidence.

And if we could go to the response to IR-6(a) and (b).

And if you could pull up that chart.

BY MR. MacDOUGALL:

Q. So for '23 to 2025, we see PHP load forecast. And then we say -- see actual PHP load; correct?

A. Yes.

Q. Okay. So if we can just try to remember those numbers or write them down, the forecast was essentially 985, 813 and 810.

A. Yes.

Q. Okay. And now if we can go back to the Synapse response, IR- 24.

And if we look there, we'll see there's the 810 for 2023. We go to the next page. Or the last page, I'm sorry, for 2025.

MR. MacDOUGALL: Go up to 2023 first, Mr. Norwood. Just go up to the first page.

BY MR. MacDOUGALL:

Q. So we see the 965 that we just referenced as forecast.

Go to the next page. 813. And the next page. And 810.

A. Okay.

Q. And those were the numbers that we saw under the forecast figures.

A. Correct.

Q. Correct. So this was developed on forecast data.

A. I accept that.

Q. Okay. Now, the numbers that you have, the one -- can we start at 2023 again, Mr. Norwood?

So the 130 then to the next page, the average running load the 130.

Go to the next page, please. The 125. And then the next page for 2025, the 128.

Now, those numbers are identified as average running load based on the PHP forecast figures, correct?

A. Yes.

Q. Okay. And do you know how they derive average running load, what NSPI meant by average running load?

A. I don't exactly, but I believe the rest of the table is giving an indication of how that

works.

Q. Yeah. What they do, subject to check, is they actually subtract PHP's forecast down days before they do the math.

A. Yeah.

Q. So the 130 is not based on the full year's 8,760 hours, but rather, it's based on 7,464 hours subject to check. That's 54 days or 1,296 hours less.

A. I think the one we have on the screen is -- you're referencing 2023, and the one we have on the screen is 2025.

Q. Sorry.

A. But if we --

Q. If we could go back to 2020.

A. Yeah.

Q. Yeah.

A. But yes, that is exactly what I understand happened, is that someone looked at this and

said, as a high load factor customer, PHP will tend to operate in OM 5 and 6. Those are preferred models when it's under a CBL.

But as the witnesses for PHP said, they wouldn't run that all the time because (a) they need to do maintenance and (b) it would produce too much product. So they would actually take some periods operating like that and some periods down. And this appears to suggest that the down periods would be approximately 54 days.

Q. Correct.

A. And so those 54 days would yield 16,000 megawatt hours, I believe that is. And the running days would -- would yield nine 969. So it's -- if you look over to the right, it's more like there are down days where they tend to run at 12 megawatts and they're running days where they tend to run at 130.

Q. Correct.

A. don't know how exactly one comes up with the 16,202 or the other like those. I don't know

which comes first because I believe it was hard entered numbers, but it's -- it fits with my understanding of how industrial customer loads tend to look.

Q. Correct.

A. Yeah.

Q. Okay. But that average running load removes the down days, the hours, and then just averages the hours that PHP was actually running. Not the days it was down.

A. The days it was anticipated to run as a forecast.

Q. Forecast.

A. But yeah, exactly.

Q. Correct.

A. That it reprofiles them on this CBL concept to be a flat load.

Q. In the days that they're running.

A. Right, 311 days of flat load and 54 of downtime.

Q. Correct.

A. Yeah.

Q. And so, Mr. Bowman, we've just added a column here that has average all days that would show what the average load over the full year would be if you included all 8,760 hours. And that's how we came up with the numbers in the yellow column called Average All Days.

A. I see that. The numbers are a smidge higher than I would expect, but I'll accept your numbers for the purposes of this.

Q. And then what we have done is for the three years 2023, '24 and '25, we've taken the actual load that PHP ran at that we showed in the prior IR of 669, if we could go down to the next number, 765, and to the next one, and 690.

We could go back to the other IRR if you wanted to, to check those, or you can take them subject to check that that's what was shown as the actual PHP load

in those three years.

A. I take them subject to check. That's fine.

Q. Okay. That's great.

And then if we could go up to 2023. You'll see for all days in the year using the actual load from those years, you get a value of 7,647 and 2,023. If we go to the next page, 8,739. And if we go to the next page, 7,885.

A. Correct. I see those numbers and those look like they make sense to me mathematically.

Q. Okay.

MR. MacDOUGALL: Now, can we go to Exhibit N-1?

THE CHAIR: Just before we do, Mr. MacDougall, that should probably be marked as an exhibit.

MR. MacDOUGALL: Yes. I'm sorry, Mr. Chair. Yes.

THE CHAIR: So that would be N-51.

EXHIBIT NO. N-51: PHP Aide to Cross - Synapse IR-24 Attachment 1

MR. MacDOUGALL: Thank you.

If we could go, Mr. Norwood, to N-1.

And we want to go to Attachment 1, page 8 of 8. And if we can look at the third -- the third paragraph.

BY MR. NORWOOD:

Q. And here it says:

> The savings created by NS Power dispatch of the customer load DR credit will be calculated at year end by comparing the actual system costs with the customer's actual dispatched load to a scenario where the actual customer load is replaced by the high load factor customer profile (i.e. the customer baseline CBL) which incorporates actual customer load, the dates and durations of the customer's major scheduled maintenance periods and other factors as may be appropriate to calculate the representative CBL.

And that's the language that's proposed by NSPI in the DR.

A. Yes.

Q. And NSPI has not formally requested approval of a numeric CBL in this process, have they?

A. No. And even this, I think, understates the process they need to do to generate the CBL. We heard about randomly assigning down periods and that sort of thing.

Q. Correct. So no representative CBL has been put forward for 2027 or for any other year.

A. No.

Q. No. Okay.

A. That -- actually, in fact, that was one of my criticisms in the evidence. I said if they had done that, we would have different numbers to work with. 120 was my best estimate to put down a number that I suggest they should -- should redo based on a CBL that they put their considered minds to.

Q. Understood. And the process here

actually indicates that what you do is you have the customer go throughout the year, and then, depending on that amount of load, you actually go back and create a CBL using those hours and generating a flat CBL with necessary cut-outs to match what happened during the year.

Is that your understanding?

A. Yeah, and I think with a bit more considered view of the operating modes. Like for example, your number that you put to me generated, I think, 74 megawatts ---

Q. Correct.

A. --- throughout the year.

We know from the OMs, if I have the schedule correct, at 74 megawtts PHP can't operate a TMP machine at all. So we know that because it has those discrete mechanical steps that it's actually going to be a mix of different operating levels.

Q. Correct. Great. Thank you.

MR. MacDOUGALL: If we could go back to

that attachment Mr. Norwood, I think it was N-57.

BY MR. NORWOOD:

Q. And I just want to go back earlier when I asked you about whether you knew anything about the -- how many down days there were for PHP. So this forecast showed for January and February and December 15 down days, 14 and 14; correct?

A. For 2025. Yes.

Q. Yeah. And then if we can go up by one year up to the next one, we see 15, 14 and 10.

A. Right. Again, based on PHP's forecast ---

Q. Forecast.

A. --- not based on the CBL. But yes.

Q. No, based on PHP's forecast.

And if you can go up one more, we see 10, seven and six.

A. Yes.

Q. And those months are the winter months and they're down more often than in the other months, which would be anticipated; correct?

A. For PHP's forecast. The CBL profiles it so it's not necessarily down quite as much in the winter. But I think more importantly, we have to recognize these are simplifications. It's not always a day that one goes down. They're not ---

Q. Correct.

A. They're not changing at midnight. They're changing all the time.

Q. Yeah. But they have the equivalent ---

A. Yeah.

Q. Let's just pick 2025.

If we could go to, Mr. Norwood, of essentially being offline for half of the -- half of the month.

A. Right, or under a CBL being

offline for a third of the month. The nine, nine and nine.

Q. Yeah, but earlier when we talked about the Interruptibility, the interruptibility only allows a customer to be taken off down to 30 percent of the month; correct?

That's -- that's what we went through a few moments ago.

A. Oh, I see what you're saying. Yes, but Interruptibility wouldn't allow this either because the system has to have the conditions that justify the interruptibility. The system doesn't always have that, so even under an IR, you couldn't drive this load.

Q. Well, no. No, that's it. But I'm not -- I'm not going to that point. I'm just making the point that if a customer wasn't under the DR and they were solely under the IR, they're only allowed to be interrupted 30 percent of the hours in the month.

A. Correct.

Q. And over the past three years or

so, PHP has forecasted under the DR that they could be down as much as 50 percent of the month.

A. Yes.

Q. Okay.

MR. MacDOUGALL: Okay. Mr. Norwood, if we could go to Exhibit N-25. I think that's Mr. Bowman's testimony again.

And if we could go to page 7, lines 3-7.

BY MR. MacDOUGALL:

Q. And here you say, Mr. Bowman:

> Many of the specific parameters for the tariff in 2026 and 2027 (such as the peak loads and energy amounts) were presented as part of the recent NSP General Rate Application (GRA) negotiated settlement. However, the settlement provided that in relation to the current application, it remains open for all parties to take any position they so choose, including whether each of the PHP, ADC and tariff filings is inconsistent with the load characteristics and basic structure as set out above.

Correct?

A. Yes.

Q. Okay. And then if we can go to page 8, lines 10 to 12.

And here you say:

> The ELID as proposed by NSP contains a number of assumptions and calculation approaches that do not appear to properly reflect the cost or value of the service provided, nor fair and consistent treatment between PHP and other customers served above the line.

Correct?

A. Yes.

Q. Okay. And the assumptions and calculations you refer to here are those that were included in the settlement agreement?

A. No.

Q. Okay. Can you can you let us know what the assumptions and calculations, approaches that do not appear to properly reflect cost or value of service

provided, nor fair and consistent treatment between PHP and other customers served ATL are?

A. Yes. The -- as I said, the focus that I took was to look from first principles at the Cost-of-Service Study and how the loads were being estimated in each case starting before application of relevant riders. And I did not find that PHP's load was forecasting the Cost-of-Service Study before application of the riders. It was forecast effectively after application of the DR.

I think that's the consistency point that I had -- that I was intending to raise there primarily. There are some other small ones, but primarily it's that.

Q. Thank you, Mr. Bowman. Those are all my questions.

THE CHAIR: Nova Scotia Power?

MS. POWER: My questions were well canvassed by my friend. Thank you.

THE CHAIR: Mr. Mahody?

MR. MAHODY: I have no questions, Mr. Bowman. Thank you.

THE CHAIR: Mr. Melanson.

QUESTIONS BY MEMBER MELANSON

Q. Mr. Bowman, just following back up on the issue of the impact of the dispatchability of the load under the ELIADC and actually continuing forward under the ELID and the impact that has on the numbers, the eight -- well, I guess 65 megawatts and the 120 -- well, 65 megawatts that were used by Nova Scotia Power.

So your -- your methodology does not have that same impact from Nova Scotia Power's being able to dispatch the power; right? Yours does not have that same issue.

A. I will try to answer the question, but if I missed it, please let me know.

Q. I'll just rephrase it.

A. Okay.

Q. I'll just rephrase it.

The 65 megawatts that's been used by Nova Scotia Power, as I understand your evidence and by others that have made the same point, but the point being that that number was influenced by the fact that the historical average had a dispatchable rider that brought it down during the 3 CP period. And so that created a -- from your perspective, a flaw in the -- in the analysis of what the peak number should be -- the 3 CP number should be. Am I right about that?

A. Yes. And it also creates a challenge for anticipating how this will work the next time.

Q. Sure. Because the same problem will keep repeating if we use the same methodology.

But what I'm asking is, your methodology does not have the same issue because you don't use the historical average in the same way you use the actual average, but adjust it for certain factors. Am I right about that?

A. I suggest that you use the expected high load factor profile of the customer for the test year == not necessarily backward looking, but for the test year in a manner that's sort of consistent with the operating modes that are needed for them to produce paper to come up with the peak in the cost of service. So it's not burdened by that what happened. It -- and it doesn't have that uncertainty for next time as to whether you're going to end up with 65, going to -- going to 100 or going to 10.

Q. Okay. But similarly, the proposal from PHP would not be burdened by that same issue with respect to the -- using the historical averages going forward because there's essentially an eight megawatt peak.

A. Yes. And I think I addressed that earlier when I said I don't come to the same conclusion as Brubaker, but I understand where they're coming from. They've at least got what I would say is a principled approach to looking at the thing and I think the issue we -

- we both run into is, what is this DR thing and how does one deal with it.

Q. Sure.

A. It's the -- the practical effect is on the -- is primarily on the IR, but it depends on how one thinks about the DR. And I think that's where we have differences. But I understand where they're coming from in a principled sense.

Q. Sure. But the resulting numbers, when you look at the two proposals, are starkly different.

A. Right.

Q. So if we accept one, it's going to make a huge difference in whether or not -- the considerations that PHP may have for the tariff. Would you agree with that?

A. I definitely agree with that, although -- yeah, there is a -- there is a wide range of possible outcomes and it's like ---

Q. Well, when you say it's a wide

range, wouldn't you agree that right now, if we don't accept Nova Scotia Power's numbers that came from the settlement agreement, that we have two options that have been presented to us in the evidence with respect to this this -- this CBL issue?

A. Well, I think, with respect, there's probably more variables available than that because I think you've heard different arguments, for example, about transmission versus generation. You might conclude, well, transmission has no savings. so that we'll talk 100 or 120 or whatever. They'll put that one over -- like you know. But then with generation, we'll think about it differently.

And maybe with generation, you could say, well, I love Mr. Bowman's 120. I understand the rationale, but I don't buy the idea that the DR pays for interruptibility. I still want to give a credit for interruptibility, so I'll set the DR value at 112 megawatts to go with the 120.

And so I think there are sort of a degree of middle -- middle ground if you like. There's also that issue of is an interruption worth $7 and -- 7.887 or is it worth or is it worth 13.10, which has some other practical impacts. But I don't think it's quite as much of a jump ball, one extreme or the other.

Q. No. I was considering not so much that -- I know there's a number of different issues that are being raised.

A. Yeah.

Q. I was considering more on the issue of whether we use the 120 or the eight for the -- for the CBL.

A. Yeah, I have pretty significant concerns about using the eight because I think it's entirely inconsistent with the idea that this Board set out that PHP should be an above the line customer that pays for bricks and mortar and is in the pool, if you like. Eight is pretty much taking one's self back -- right back out of

the pool.

And that eight barely pays for the variable costs through the BCF, the base cost of fuel adjustment that comes back through the -- through the rates.

Q. And with respect to sharing the benefit with respect to the DR, have you -- do you have an opinion on that?

A. Yeah. My opinion is that if PHP can bring benefits that are demonstrable through the DR, they should get the benefit of that. Yeah.

To the extent they're sharing, I think it's more about protecting from the risk of an overestimate being used. And I -- I'm sorry that I can't give you a percentage like Mr. Mahmudov of 20 percent or something, but I think I'm probably not best situated to do that. But I think Bates White's evidence does address pretty well what one might think about as the degree of potential overestimation.

THE CHAIR: Mr. Norwood, if we could pull up Exhibit N-25 and to go -- actually, it's up there, I think. Now go to page 10, please. And the paragraph that begins at line 4.

QUESTIONS BY THE CHAIR

Q. Mr. Bowman, in this particular paragraph, you're making some comments that I understand relate to the interaction between the DR and wind generated from Goose Harbour? That's ---

A. Yes.

Q. Yeah. And I may not -- I'm not sure I understand your point or I may not understand the evidence clear, but if -- Nova Scotia Power is calculating the CBL after the fact so it's a retrospective analysis based on what -- the actual load in the year and its actual scenario versus its counterfactual flat or optimised CBL load. Both include actual cost impacts from all wind resources, including the PHP wind farm as they occurred.

Does that kind of neutralize or negate

the issue of the PHP wind farm from the DR credit issue if it's accounted for the same way in both the actual and the counterfactual scenarios?

A. It -- I'm not sure how one would do that, but it's not my understanding of what actually happens. And so it's possible -- I do go on to say this is somewhat complicated. So I think it's -- it helps to walk through what I understand is happening and we can -- maybe you'll see where I'm coming from.

My understanding is that the Cost-of-Service Study is being run to price approximately 300 gigawatt hours of supply and that will generate an energy rate. And that rate will then be applied by -- paid by PHP for all the energy they consume from NSP. It won't be applied on the 500, but it'll be applied on the 300-ish. And if the 300 into 200, it would be applied on 200.

But when you actually get to the DR calculation in the -- in the FAM, the hypothetical load reprofiled from the actual load, those two loads being

compared, are -- both use 800 gigawatt hours of PHP's use regardless of whether those -- those gigawatt hours came from PHP's wind in the first instance or came from NSP supplies in the first instance.

So PHP has a very large opportunity within those 800 gigawatt hours to cause, if you like, fuel savings compared to average to benefit from fuel savings compared to average dispatch for -- on NSP's system. And I think that -- because it's based on the incremental, my understanding is it won't be based on Goose Harbour's costs or output. It'll be based on whatever the fuel production units on time -- online at the time are for each hour in those reprofiled hours.

Q. So I'm not sure I followed that, but my understanding is Nova Scotia Power -- well, the actual cost during the course of the year is one scenario, and we know that. And -- but maybe what I heard you say, is they're going to be rerunning that as well in some way? Is that your understanding?

A. That is my understanding, that in the -- NSP will produce effectively, call it, two FAM reports. One is what did we actually spend and one is what would we have spent if PHP moved its 800 in a flat load rather than in a profiled load. And the comparison between those two will yield a number which is then plugged in as a FAM cost to be recovered from all FAM customers.

Q. Right. In the actual scenario, though, they're not -- it's not your understanding they're using the costs that were actually incurred by the system in the year, they're running it through the model instead?

A. Well, the costs incurred as compared to the hypothetical costs that would have been incurred if PHP's 800 gigawatt hours look different.

Q. Right.

A. Yeah.

Q. And if the wind resources are fixed in both those models, does that negate the issue that you're raising here?

A. No, because if the wind resources are fixed, they're not the incremental supply that's being reprofiled. They're somewhere lower in the stacking order, if you like. The incremental supply that's being reprofiled is the different sources of imports and thermals and other things that are actually managed from Nova Scotia Power.

Q. Okay. And it's not your understanding that they're -- the incremental costs is based on the other resources moving around wind and other renewable resources.

A. My understanding would be that -- and I could be wrong, but my understanding would be it's the -- the incremental cost would be the resources that are actually considered to be marginal at any given time and that they can manage, not the ones they can't dispatch.

Q. Okay. Thank you.

THE CHAIR: Any questions arising from board questions?

Okay. I'm not seeing any. Any redirect, Ms. Rubin?

MS. RUDDERHAM: No. Mr. Chair.

THE CHAIR: Oh, sorry, Ms. Rudderham.

MS. RUDDERHAM: No worries.

THE CHAIR: Mr. Bowman, thanks as well for your participation in this proceeding and your evidence. You're good to go now.

Synapse or Bates White next?

MR. MAHODY: Synapse, I believe, Mr. Chair.

Melissa Whited from Synapse will be up next.

MS. WHITED: Good afternoon.

MR. MAHODY: Good afternoon, Ms. Whited.

MELISSA WHITED, Affirmed

THE CHAIR: Mr. Mahody.

MR. MAHODY: Thank you.

DIRECT EXAMINATION BY MR. MAHODY

Q. Ms. Whited, can you confirm that you've prepared evidence in this matter and it's been marked as Exhibit N-21 and that you ---

A. Yes.

Q. Sorry. And that you filed IR responses to the Industrial Group, NSP and PHP and those have been marked as exhibits as well?

A. Yes.

Q. And your Appendix A to your report, Exhibit N-21, contains a copy of your CV.

A. Yes.

MR. MAHODY: Ms. Whited is known to the Board, Mr. Chair, and to the parties, and her resume has been attached to her evidence since it was filed. I would ask that she be qualified as an expert in utility regulation, cost allocation and rate design, and permitted to provide opinion evidence in those areas.

THE CHAIR: Any questions on

qualifications or objections?

She's so qualified, Mr. Mahody.

MR. MAHODY: Thank you,

BY MR. MAHODY:

Q. Ms. Whited, are there any corrections you wish to make to any of your pre-filed evidence or IR responses?

A. No.

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

A. Yes.

Q. And do you adopt your pre-filed testimony and IR responses as your evidence in this matter?

A. Yes.

Q. Now, Ms. Whited, after your report was filed, Exhibit N-21, additional evidence has been placed on the record, both in writing and orally at the hearing.

Has any of that evidence caused you to modify or alter the opinions or recommendations expressed in your pre-hearing testimony?

A. The only thing that has caused me to do is to -- is NS Power's reply evidence pointed out that the interruptible credit payments from customers would be offset by the credits received and so that concern that I raised may not be an issue.

I have not verified that, but I want to acknowledge that I have seen that evidence submitted. And if that is true, then it allays one of my concerns.

Q. Thank you, Ms. Whited.

MR. MAHODY: Mr. Chair, the witness is available for questions.

THE CHAIR: Ms. Power, should I come back to you?

MS. POWER: No questions, Mr. Chair.

THE CHAIR: No questions?

Mr. Roberts.

MR. ROBERTS: No questions. Thank you.

THE HAIR: Ms. Powell.

MS. MacADAM: Thank you, Mr. Chair.

CROSS-EXAMINATION BY MS. MacADAM

Q. Good afternoon. I actually just have one question for you at the moment.

MS. MacADAM: So if we could go, Mr. Norwood, to your evidence on Exhibit N-21, please.

I'm looking at page -- PDF page 6 of 16, and at lines -- beginning at the top of the page so that lines 1 to 4.

BY MS. MacADAM:

Q. So in your evidence, you state here at lines -- halfway through line 1:

> Instead, I recommend that the Board direct PHP and Nova Scotia Power to negotiate an alternative credit value that would induce PHP's participation while ensuring that a portion of benefits is retained for other customers.

Have you done any work on determining

what that alternative credit value could or should be?

A. I have determined some of the bounds. So theoretically, from an economics perspective, you could pay up to the avoided cost of new generation as -- you know, as a credit to PHP for reducing its load during peak hours and therefore avoiding having to construct new generation on the system.

However, PHP is also an embedded cost customer who benefits from the system and particularly the transmission system so I believe that PHP should also be contributing something to those costs. Therefore, you know, I think it would be reasonable that the credits perhaps be larger than the $8 that was proposed but less than the full demand charge.

And I don't have the portion of the demand charge that is related to transmission so I can't say exactly where that should fall.

Q. Okay. But somewhere more than eight and less than the demand charge. Is that what you're

saying?

A. Yes.

Q. Okay. Thank you.

Thank you. Those are my questions.

THE CHAIR: Industrial Group?

MS. RUDDERHAM: No questions.

THE CHAIR: Port Hawkesbury Paper.

MR. MacDUFF: No questions.

THE CHAIR: Mr. Mahody, you don't.

Mr. Melanson.

MEMBER MELANSON: No. No questions.

THE CHAIR: And I don't have any either, Ms. Whited. Thank you.

So far, at least, you have the record for quickest witness here in this proceeding. But notwithstanding that, your participation and your written evidence and being here today is very much appreciated.

And I think with that, you're good to go. So thank you very much.

MS. WHITED: Thank you.

THE CHAIR: Mr. Mahody.

MR. MAHODY: Even my most optimistic predictions of time have been exceeded with that one.

But next up would be Bates White. I'm unclear about whether or not Mr. Musco or Mr. Cain are available to come on the screen now, but if they are, I'd invite them to do so.

(SHORT PAUSE)

MR. MAHODY: Mr. Chair, just perhaps while we wait for Mr. Cain to get reconnected, I had circulated to the parties and to the clerk CVs for Mr. Musco and Mr. Cain over the lunch hour today. I would ask that those be marked as an exhibit to the hearing.

THE CHAIR: Okay. We'll Mark Mr. Musco's CV as N-52 and Mr. Cain's is N-53.

EXHIBIT NO. N-52: Vincent Musco's CV

EXHIBIT NO. N-53: Collin Cain's CV

MR. MAHODY: Thank you, Mr. Chair.

We can see you now, Mr. Cain.

MR. MAHODY: Could I ask that the witnesses please be affirmed, Mr. Chair?

VINCENT MUSCO, Affirmed

COLLIN CAIN, Affirmed

THE CHAIR: Thank you.

Mr. Mahody.

MR. MAHODY: Thank you.

DIRECT EXAMINATION BY MR. MAHODY

Q. Gentlemen, could you confirm that you've filed evidence in this matter that's been marked as Exhibit N-20 and that you've responded to IRs from PHP, the Small Business Advocate, the Industrial Group and NSPI?

A. (Musco) Yes.

A. (Cain) Yes.

MR. MAHODY: And both Mr. Musco and Mr. Cain, Mr. Chair, have appeared before the Board on occasions and are well known to the parties. Their CVs have been circulated.

I'm going to ask that they be qualified as experts in utility regulation and rates and permitted to provide opinion evidence in each of those areas.

THE CHAIR: Any questions on qualifications or objections?

They're so qualified, Mr. Mahody.

MR. MAHODY: Thank you.

BY MR. MAHODY:

Q. Gentlemen, are there any corrections required to your pre-filed testimony?

A. (Musco) No.

A. (Cain) No.

Q. And are the facts on which your opinion are based true and accurate to the best of your information and belief?

A. (Musco) They are.

Q. And do you adopt your pre-filed evidence as your testimony in this matter?

A. (Musco) Yes.

Q. Okay. And after filing your report in this matter, additional evidence has been placed on the record. Has any of that evidence caused you to modify or alter the opinions expressed in your report?

A. (Musco) Nothing has changed our opinions. I think in multiple cases we identified areas for additional information which could have helped the record and which may have been filed to date, but none of our opinions have changed.

Q. Thank you, Mr. Musco.

MR. MAHODY: Mr. Musco and Mr. Cain are available for cross-examination, Mr. Chair.

THE CHAIR: Ms. Power?

MS. POWER: Nothing from us, Mr. Chair. Thank you.

THE CHAIR: Mr. Roberts?

CROSS-EXAMINATION BY MR. ROBERTS

Q. Good afternoon. I just have one area I wanted to explore with you and that's in -- I'm

looking again at Exhibit N-20, the last segment, "Treatment of Goose Harbour Output".

And in particular, I'm looking -- this is paper page 29. Thank you.

And I'm looking in particular at line 20:

> Our conclusion is that the PSA treatment of Goose Harbour output has significant potential to undermine the proposed treatment of PHP as an above-the line-customer under the ELID.

What features of the PSA will undermine the proposed treatment of PHP as an above the line customer?

A. (Cain) The complications that the treatment create in the accounting for actual cost to serve is a primary concern. There was some conversation yesterday about the intent for the PSA to -- and the PPA for a behind the meter generation structure. And to the extent that the that treatment is -- doesn't reflect what

is actually going to happen, it injects significant complications into how cost to serve PHP is actually determined and how costs are recovered under the energy chart and the other rates.

I would say -- you know, for example there's no consideration of transmission limits to the PHP facility. There's no consideration of losses associated with moving energy from the Goose Harbour facility to serve PHP load and the ability to move generation from the wind farm to any later period. The fact that there's no correspondence between the period in which generation occurs and the period in which load occurs creates an additional complication.

It creates a situation that is like having the energy stored, but it's not actually stored. So there are a number of complications in which the treatment under the PSA provides some significant benefits to PHP and they are not fully reflected in the cost to service under the GRA or the determination of rates.

Q. The latter problem you identified is that the banking the way you -- what you characterize as allowing them to bank excess Goose Harbour output?

A. (Cain) Yes.

Q. Okay. And if it's -- if this results in PHP not paying an appropriate share of the costs, where will those costs be borne?

A. (Cain) I think what we've heard confirmed in NSP's reply evidence and as well as evidence at hearing is that there's an expectation that -- that all deviations will be addressed in a -- in the deferral mechanism. I suppose in some sense that provides a limited amount of comfort, but in the absence of an accurate determination of an allocation after the fact, those costs would be borne by other FAM customers.

Q. One of the scenarios which you explore which I think you admit would be an extreme one, though, is that PHP net load could be as much as zero. How would that happen?

A. (Cain) As explained in our evidence you know, it's an illustration and it is potentially an extreme scenario. Goose Harbour generation, actual generation could be considerably higher than the P90 value that is assumed. The amount of energy that was assumed in the GRA reflected a plant size of 130.5 megawatts and the anticipated size, as we've heard here in the hearing over the last few days, is 168 megawatts.

So there are a couple common -- combined possibilities that the plant side is -- plant size is going to be larger. The expectation is that that interconnection is going to be achieved at that higher rate that the output will be higher than the P90. That's, you know, by definition, with a 90 percent certainty year to year. And it's also possible, of course, that PHP actual load, gross load is lower.

You can create a scenario as I did that shows that you could get to a net zero consumption. I understand PHP thinks that that is unlikely, and I think

NSP would also say that that's unlikely, but it is clearly feasible.

Q. So what you've -- you've got a recommendation here that the NSPI evaluate cost recovery under the ELID tariff at the conclusion of each annual period.

Do you have any other recommendations to make regarding the risks that you've identified in this portion of your report?

A. (Cain) I do think that calculating rates that reflect the latest available information, particularly when their material is important. So PHP has advanced that their load should be represented at 774 gigawatt hours rather than the 810 gigawatt hours assumed in the GRA. I think that that's appropriate.

I think it is also appropriate to reflect expected output of the Goose Harbour facility at the full 168 megawatt capacity and at a P50 value that creates some symmetry.

The potential that generation from the Goose Harbour facility is higher or lower is relevant to the risks that are borne for recovery of fixed costs under the charges to PHP. So if there's a risk that is being balanced between cost recovery from PHP and cost recovery from FAM customers, I think it's appropriate to create a symmetrical, you know, expected value rather than an extreme value, an extreme low value of expected output from the Goose Harbour facility.

So I think a -- reflecting both of those in the determination of the energy charge would be appropriate.

Q. Thank you very much.

THE CHAIR: Small Business Advocate?

MS. MacADAM: No questions. Thank you.

THE CHAIR: Industrial Group?

MS. RUDDERHAM: We do have questions. Can we ask questions?

THE CHAIR:

CROSS-EXAMINATION BY MS. RUDDERHAM

Q. Good afternoon, Mr. Musco and Mr. Cain. My name is Brianne Rudderham, and I'm going to be asking questions on behalf of the Industrial Group.

I'll ask the questions out to the panel and I'll allow it -- allow you two to decide amongst yourselves who's best to answer each category of questions.

First I want to ask some questions about the concerns that have been raised by Bates White in relation to load forecasting for 2027 and the impact on energy charge for PHP. Who should I address these questions to?

A. (Musco) I believe those would be for Mr. Cain.

Q. Mr. Cain. Okay.

So in Bates White's evidence there's some concerns raised that using the forecasted net PHP load that is too high for the purposes of calculating the energy charge may result in an energy charge that is too low.

Is that correct?

A. (Cain) That's correct.

MS. RUDDERHAM: And Mr. Norwood, if you don't mind bringing up Exhibit N-20, and I'm looking specifically at page 15, lines 20 to 21.

Sorry. It starts at -- yeah, 20.

BY MS. RUDDERHAM:

Q. So I'll just read this into the record. It says:

> By applying a net load for PHP that is too high, the resulting energy charge rates proposed by NSPI's Application are too low, increasing the likelihood that PHP does not contribute appropriately to system costs.

So I want to ask you about this next sentence.

> In the absence of any mechanism to correct for such a shortfall in cost contribution, other FAM customers would be exposed to making up the difference.

So am I correct here your concern is

that if the energy charge does not reflect the accurate load and there's no separate mechanism to address shortfalls for fixed costs, those costs would fall on FAM customers?

A. (Cain) That's correct.

Q. Okay. So this same thread of concern is reflected a couple other times in the evidence. I don't think we need to bring it in, but it's on page 16 as well and on page 17.

So what I don't understand, and I'm hoping you can clarify for me, is why does Bates White believe that a load forecasting error and reduction in contribution to system costs would be recovered from other FAM customers?

A. (Cain) Well, there's a total pool of costs that have to be recovered, the fixed costs and the variable costs of operating the system. Those costs have to be recovered unless they're going to be relieved by the province, I suppose. You know, there's no other mechanism

for drawing revenue. There are no shareholders in this case for to assume costs.

And I would say that, you know, the corrective mechanism that we're imagining, whether it's the deferral account or some other mechanism, would be to ensure that there wasn't an unreasonable deviation from the expectations under which rates were set and the costs that were ultimately recovered. I think that it's -- you know, it's amounts that are going to have to be recovered through rates, whether in the current year or in subsequent years through a deferral mechanism that would be at issue.

Q. Okay. And Mr. Cain, you'd agree that in Bates White's evidence, you've confirmed that in Bates White's view, the deferral account -- the PHP deferral account as set up in the GRA would not cover for distortions arising from PHP net loads. That would be substantially lower; correct?

A. (Cain) I think what we have seen subsequently from NSP's reply evidence, you know, I believe

that there is a categorization of all the elements that would be addressed in the deferral mechanism.

I think NSP lists actual PHP load, the actual output of Goose Harbour as elements that would be subject to that overall deferral mechanism review.

So you know, without specifying the details of how that mechanism would be applied, at least conceptually, NSP has advanced that those would be encompassed in that deferral mechanism.

Q. And I -- I didn't mean to cut you off there.

A. (Cain) I was just going to say that, you know, to the extent that that provides some comfort that there's a way to correct substantial deviations, it is subject to the details of how that would work.

Q. Okay.

MS. RUDDERHAM: And perhaps, Mr. Norwood, if you don't mind pulling up page 17 of N-20,

Bates White's evidence here.

BY MS. RUDDERHAM:

Q. So starting at line 5, the question is:

> Would the PHP deferral account correct for the potential cost recovery distortions under the proposed energy charge?

Then on line 7 answer, No". And then it goes on. And it quotes from the deferral account.

If you don't mind scrolling down a little bit further, Mr. Norwood. There.

So then at 13, it says:

> This wording suggests that no deferral would apply to correct for the distortions arising from PHP net load being substantially lower than what NSP modelled in determining the ELID energy charge rates.

So I just want to confirm, in Bates White's opinion, based on the deferral account as set up, Bates White's opinion is that any load variances would not be recovered or costs would not be recovered as part of

that deferral account.

A. (Cain) So, you know, we're not advancing ourselves as attorneys and we also recognize the, you know, sort of packaged element of the settlement agreement.

My lay reading of this language made me concerned that the deferral account would only address the ELID as established in the GRA not being in place as of January 1st, 2026. So my concern was that that provision for the deferral account only seemed to be -- at a bald reading of the language, to my eye, again, a non-lawyer and non-participant in that settlement agreement, made me think that the deferral mechanism was intended only to capture, you know, not getting the ELID into place as opposed to addressing deviations from the rate setting relative to what actually occurs.

So my -- sorry. My original response here is that, you know, I would see this a little differently if we accept what NSP has put into its reply

evidence, which seems to be a more encompassing definition of what the deferral account would address.

Q. Yeah. And I'm not asking for what NSP's interpretation is of this.

When I read this evidence, it suggested to me that Bates White was saying it did not view these load variance impacts as being covered under the deferral account. Am I misinterpreting what is here from ---

A. (Cain) That is what is stated here and that was based on our reading of the simple language of the settlement agreement.

Q. Okay. So in your evidence elsewhere where you're saying if the energy charge is too low, those costs could fall on other FAM customers, so I just want to clarify how those costs would fall on other FAM customers. How would that be recovered from other FAM customers?

A. (Cain) If there are amounts that are, you know, essentially unrecovered for the system that

that are then determined to be the obligations of the system as a whole as opposed to PHP -- you know, in other words, if you're going to -- if you're going to determine that there's, you know, unrecovered costs for a given year, then we assume that the utility has the opportunity to recover those costs. So if they are not defined in such a way as to -- you know, as to define responsibility because the rate was set wrong in the GRA, then there's a potential for those costs to be recovered for load across all load. And that would be all FAM customers.

Q. I think in your answer previously was in order for those to be recovered at a later time, there'd need to be a deferral mechanism established, correct?

A. (Cain) Yes.

Q. Okay. And currently, NSPI can't recover after the fact of variance in, let's say, OM&G costs except for storm; correct?

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

Q. Okay. And in the FAM AABA process, that's for variances in fuel costs; correct?

A. (Cain) Yes.

Q. And that's tracked intraclass; correct?

A. (Cain) Yes.

Q. And the FAM doesn't track or recover for load variances for other classes; correct?

A. (Cain) Subject to check. I don't disagree with that.

Q. Okay. So when you're saying that if the energy charge is too low, why or how would that be borne as a risk to FAM customers and not as a risk to NSPI?

A. (Cain) It could be -- it could be a risk in either case. I guess what I would say is that in the absence of, you know, absolute clarity of what's going to be dumped into a deferral mechanism, that the recovery of fixed costs is going to be an open question. I -- you know, it's not clear to me that there's any absolute

protection that fixed costs would be eaten by NSPI and not other FAM customers if fixed costs are not recovered from the general rate setting process. It was not my understanding that there is a general protection against recovering costs appropriately if the GRA did not produce perfect rates.

Q. Okay. And it would be up to the Board to interpret what that deferral account would cover; correct?

A. (Cain) That's correct.

Q. And in Bates White's evidence, there's also raised an issue for variability and unpredictability of load forecasting as a concern in relation to calculating the DR credit; correct?

A. (Musco) That's right.

Q. Okay. Is this directed to Mr. Musco?

A. (Musco) To the extent you're going to discuss the DR credit, then yes.

Q. Yes. And I'm I'm -- wanted to ask questions about the load forecasting and those errors there.

MS. RUDDERHAM: So just to be clear, Mr. Norwood, if you don't mind bringing up pages -- page 21 of Bates White's evidence and 20 just to orient ourselves.

BY MS. RUDDERHAM:

Q. So this is the section of the evidence I was talking about, 21 and page 22.

I assume that means you drafted this section, Mr. Musco?

A. (Musco) Yes.

Q. And actually, I think in your evidence the actual load has been redacted. And at least for 2023, 2024, 2025, they've now been put on the public record; correct?

A. (Musco) You're asking me for confirmation of that?

Q. Well, were you listening to the

last session?

A. (Musco) I was, and that is my understanding. But it's very much subject to check. And given that it's a matter of confidentiality, I would -- I would be extra careful to make sure that's the case.

Q. And maybe I can just ask you some questions more generally.

So on your -- on pages 21 and 22, you've analyzed both the forecasted costs on the -- on the next page there, Mr. Norwood on page 22 -- the forecasted actual load with the actual load and then raised what the forecasting error in gigawatt hours and also in percentage; correct?

A. (Musco) Correct.

Q. And I know that some of these actuals are not confidential any more, but generally speaking, in each one of these years, you'd agree that PHP's forecasted load has exceeded the actual load; correct?

A. (Muscat) Ms. Rudderham, respectfully, I'm just a little concerned about confidential confidentiality. To answer that question, I would have to -- I, in my view, would at least be at the edge of identifying something that's otherwise confidential.

Q. Fair.

MS. RUDDERHAM: And this is part of the reason, Mr. Chair, as to -- you know, confidentiality has kind of been all over the place in this proceeding. So we're just going to confirm.

(SHORT PAUSE)

BY MS. RUDDERHAM:

Q. Apologies, Mr. Musco. We were just speaking with counsel for PHP and they said if you are aware of the numbers and you could affirmatively agree that in each of those years the forecast load has exceeded actuals, you can, in fact, confirm that on the record.

A. (Musco) Thank you. I'm just

pulling up the numbers myself to confirm.

Yes. That's confirmed.

Q. Okay. Now, when Bates White did this analysis of the forecasting being consistently lower than actuals -- and maybe you can elaborate for me, why would that impact the DR credit if the calculation of the DR credit is done based on actuals at the year end and then the actuals on a levelized high load factor -- or sorry, high load CBL?

A. (Musco) I think I think what we're getting at here was more about the premise of the optimality of levelized load and the realisticness (sic) of levelized load for PHP. And what we were attempting to demonstrate using the data was to show that PHP's own forecasts of its load exhibited forecast error, which I can't get into the specifics here. But in there, there are realities that PHP faces that makes the realisticness(sic) of that levelized load assumption, as we say, more of a shaky premise.

Q. So is it less about the forecasting of the overall load and more about the load profile?

I guess I'm just not 100 percent clear on why this would impact the credit and I'm genuinely just trying to understand why the unpredictability of PHP's load would impact that.

A. (Musco) Again, we -- PHP has identified in this proceeding and we identify in our evidence factors that make it difficult to know what PHP's load will be and make it -- and challenge PHP to maintain a levelized load in actual operation. And so when -- when the premise of the DR credit is that PHP would -- you know, if it was -- if it was indifferent to price signals to system conditions, would operate in a levelized manner in this highly predictable manner.

This was evidence we were putting forth, among others, that -- other pieces of evidence saying that that is not -- that's not obvious to us based

on the data and based on the evidence filed in the proceedings.

Q. Okay. So I guess the issue isn't necessarily with the pattern of over-forecasting annual load and then under-consuming in relation to how you would calculate the DR credit. It's more about the unpredictability of where PHP's load would be at any given time. You can't just assume that it's level.

Is that what I'm understanding about the impact for the load?

A. (Musco) Yeah, that's generally right. It's not about -- I mean, we, we provided the detailed data and, you know, for -- to be thorough and transparent, but no, it's not about the skew one way or the other when it comes to this issue of the DR credit.

Q. And you'd agree that for an above the line customer generally the costs are embedded and they're based on what the forecast of the costs would be.

Is that correct?

A. (Musco) That's -- that's my general understanding. Yes.

Q. Okay. Now, in relation to the DR credit, Bates White has identified several concerns with the credit, I think it's numbered one 1 to 6. And the one I wanted to, to kind of dive into right now is Bates White has some concern about the level of discretion that would fall on NSP in calculating the credit. Fair characterization of one of your criticisms?

A. (Musco) Yes.

Q. Okay. Now, I assume you were listening to the evidence last week and this week when NSPI had indicated that there would be little, if any, discretion in calculating the DR credit.

Had you heard that?

A. (Musco) I did hear the NSPI panel discussion of this topic. Yes.

Q. Okay. And I believe -- is your understanding that the -- NSPI's evidence was that the

calculation is rather formulaic?

A. (Musco) I'll do my best to give you my sense of what was said but, of course, all this is subject to check in the transcript.

But my understanding is initially, yes, that was discussed as a, you know, sort of repeatable, formulaic exercise without much discretion, if any. I think upon further questioning from Board counsel, there was -- there was acknowledgement of some discretion, particularly around the term "other factors" which is -- which was included in the ELID tariff language and in the operating protocols, the draft form of the operating protocols.

Q. Okay. And after hearing and NSPI's evidence last week, does that change or alleviate any of the concerns that Bates White has raised in relation to the level of discretion or verifiability of the DR credit?

A. (Musco) Unfortunately, on the --

on the discretion, no. Term "other factors" remains quite broad and, you know, unclear and, again, introducing some -- some subjectivity to the process and considerable latitude for Nova Scotia Power to conduct that calculation, albeit potentially subject to regulatory review.

As for -- Ms. Rudderham, what was the term you used, the second part of your question?

Q. Verifiability, like being able to verify. I think that's one of the concerns that were raised in your evidence.

A. (Musco) Yeah. Thank you.

On that, I think we're in a better place. What I heard from Nova Scotia Power was they were -- you know, in their minds, they are thinking this is going to be a highly verifiable exercise, something that can be looked at *post facto* to review what exactly was done, if there were any discretionary adjustments where those were and how they impact the calculation. So I think that was fairly positive to hear because it allows for the potential

of a more realistic and credible after the fact review.

You know, there's still that question of, you know, what exactly will be done and, you know, there's still some uncertainty there. But I think generally, on the whole, it -- the hearing did a good job of bringing out some more of that detail in Nova Scotia Power's plan on executing that end of year -- end of tariff year calculation and DR credit determination.

Q. And Mr. Musco, you've been involved in the FAM Audit for many years; correct?

A. (Musco) Correct.

Q. Now, as an auditor, what information or what documentation, I guess, would you expect to see in order to complete that verifiability or credibility of the -- of those numbers that review?

A. (Musco) So we would -- we would expect to see the -- this would be -- the actual calculation would be done, as I understand it, as a production cost simulation run for the year. We would need

to see, you know, the inputs and outputs of that calculation. We would have to understand the model that was used. If it's an off-the-shelf commercially available model, that makes it much easier. If it's some sort of bespoke proprietary model, then we'd have to dig into that model as well.

We would have to -- and then the -- you know, the challenge of the verification process is really a function of how much was adjusted. If -- and so we -- you know, we would expect NSPI to provide and be able to explain everything they did from randomizing outages to any other adjustments that they made to the -- in the production cost simulation model run.

Where it could get difficult is if the -- if any of the data that was relied upon and used in the model to adjust the model was -- it was a product of Port Hawkesbury Paper, then that's something we would have to be able to understand and dig into.

But again, if the intent of the tariff

is to allow for transparency and a review of the results and of the quantitative efforts to come up with the DR credit, I think there's reason for optimism that that would be able to be done.

Q. Thank you for clarifying that.

And what is your understanding for how or when the FAM customers would ultimately pay for the DR credit?

A. (Musco) That's not -- from the evidence in the record and from listening to the hearing these past several days, I don't know that I could tell you with certainty exactly how that would work. My understanding is that, generally, the concept is that that -- that the -- whatever the DR credit is calculated on -- as would be a credit to Port Hawkesbury Paper and would be charged to other customers that conceptually benefit from the -- from the dispatchability of, you know, the intent of the DR credit and what -- the service that PHP is providing.

But in terms of, you know, is that a -- is that spread out over the year on a single monthly bill, weekly, I don't know that that has been made clear in the record. I may have missed it, but I don't have a sense of it.

Q. No. And I also am not 100 percent clear, but I assume what you're saying when you say paid for by FAM customers, you're referring to it through the FAM ABA process or some separate FAM rider process?

A. (Musco) Yeah. I don't even know that I'd go that far. I would expect it to be FAM related cost recovery mechanism. And, you know, it could make sense for it to be in the annual reconciliations that you mentioned, Ms. Rudderham, but I'm not sure.

Q. And I assume you're familiar with the FAM POA.

A. (Musco) Yes.

Q. Could this additional charge be included or would there need to be revisions to the FAM

POA?

A. (Musco) I'm not sure only because, I mean, I -- as much as I've read the POA a number of times, I don't -- I don't have a encyclopaedic memory of it.

You know, I would think that to the extent that the POA needs to specifically call out this capitalized term from -- from a Board approved agreement, I would think you'd need -- you need a revision. If there's some more general language in the POA that allows for, you know, some lowercase reconciliation of PHP's costs, that's -- it perhaps could be used. But again, now we're getting into the world of, you know, legal interpretation, which is not my world.

Q. No. And I -- and I'm not trying to get you to go there, nor am I expecting you to have a photographic memory about that. I just genuinely was not sure and was looking for your understanding of how this was going to be recovered and if it could be recovered under

the current mechanism.

But I take your answer to be could be, could not be. You're not 100 percent sure.

A. (Musco) Correct.

Q. Okay. Now NSPI's reply evidence has stated that they developed a new methodology to quantify the value of the ADC by isolating load shifting value from changing prices; correct?

A. (Musco) Can you take me to where they say that, if you don't mind?

Q. Yes. Let me just pull up the reference here.

It's NSPI's reply evidence and that's at N-38. And the page is PDF page 23, and I'm looking at lines 15 to 19. Right there.

A. (Musco) Yes, I'd agree.

Q. Okay. And It notes that this new methodology was presented to the FAM Small Working Group and would be subject to review by that group and future FAM

Audits. That's what that says there, just summarizing that.

A. (Musco) Yes.

Q. Okay. And you're involved in the FAM Small Working Groups?

A. (Musco) I do attend the FAM Small Working Groups.

Q. Okay. And for this methodology was -- was Bates White involved with the development of this new methodology before it was introduced to the FAM Small Working Group?

A. (Musco) We did not develop this methodology. I think that the methodology which was developed by Nova Scotia Power was attempting to incorporate prior feedback from Bates White, I think would be fair to say, but we didn't develop it ourselves.

Q. And when you say the feedback, I assume what you're referring to is the recommendation 15-3 from the 2022-2023 FAM Audit; correct?

A. (Musco) Subject to check on the exact number. Yes, that's correct.

Q. It's just on the screen right there.

A. (Musco) Thank you.

Q. Okay. So was -- the new methodology that was presented at the FAM Small Working Group in Q2, was that the first time you had learned of it?

A. (Musco) It's possible that Nova Scotia Power had reached out to us in advance of the SWG meeting in Q2. In fact, I would -- I would expect that to be the case.

I would have to -- I'd have to go back and look. There have been multiple instances through -- through our tenure when, you know, Nova Scotia Power is developing something in response to a Bates White recommendation, an audit recommendation and they reasonably will -- will provide us a sort of -- access to what they're working on. And then -- and can sometimes follow up

through the SWG process.

I suspect that's the case here, but I just don't have the details committed to memory on that one.

Q. Fair. And so whether it was some time before if it was at this -- at the meeting, has Bates White, I guess, vetted it or would approve and agree with the approach that's been proposed as the new methodology?

A. (Musco) So what I would say is, you know, what they lay out here -- what Nova Scotia Power lays out here that it will remain subject to SWG review, subject to Board approval through the ELID tariff application and subject to future audits is, you know, a seemingly reasonable plan.

We have not -- we've not provided any formal opinion on it and particularly as it relates to the tariff. And so I just don't think we're -- we've gone there yet in terms of providing something that's written and assesses what they've put together.

Q. Okay. And when you said subject to Board approval in the ELID tariff, the way that I've read this sentence -- I assume what you're reading is lines 18 to 19 on the reply.

I read this to be not that it's Board approval in this process, it's for future FAM Audit review.

Do you understand that to be something different?

A. (Musco) My -- Ms. Rudderham, I was I was just attempting, perhaps not well, to read what was on screen as opposed to characterize it. But no, my understanding is -- understanding is that the methodology itself is not up for Board approval in this proceeding, that the tariff is, but that the specificity of what's in the operating agreement or the operating protocols is not.

Q. Okay. That was my understanding as well, but I just wanted to clarify that.

Based on your understanding of this new methodology for calculating the DR credit, does that new

methodology address any of the concerns that have been raised in Bates White's evidence?

A. (Musco) One area I would like to -- where there's been some additional information provided that I think is -- allays some concern was regarding forward -- use of forward replacement pricing.

In the discussion with the Nova Scotia panel, there was -- there was -- that question, I believe was put directly to them. Why use forward replacement pricing when Nova Scotia Power had been critical of its use in the past in -- during periods of high fuel price volatility, particularly in 2022?

And the response was quite helpful.

The idea is to hold constant the same prices that were used to dispatch the system and will also be used in the after the fact calculation of the DR credit. That has made some -- not some analytical sense. That makes analytical sense.

I think the one concern that remains is

I'm -- we're not convinced that that fully insulates the methodology from the potential for, you know, distorting impacts of volatile fuel prices in certain instances if there are marginal prices. If the fuel that is on the margin has a very high fuel price, that could still lead to some of those same distortions that Nova Scotia Power was worried about in '20 when they -- when they altered their methodology for the EDLIADC tariff back in -- I'm forgetting the year, but it was in response to the volatility observed in 2022. So that's a -- that's a big positive, what I heard, and helps explain why they're using forward replacement costs.

I would just say that it doesn't fully resolve the issue for us just because that -- in our view, that risk is still there for -- in some limited circumstances.

Q. And the new methodology doesn't, I assume, address the concerns that we previously were talking about in terms of the discretion to be applied to

the calculation.

A. (Musco) No, I think those are separate points. And as I understand from what I've heard from Nova Scotia Power's panel, that that discretion is very much still part of the overall process.

Q. Now, I know we talked about that new methodology is not part of the proceeding here.

In Bates White opinion, should that new methodology that's being used to calculate the credit be subject to Board approval?

A. (Musco) It's not been our evidence and it does get to -- potentially gets to a legal question.

I think, though -- I think what's important for us is to make sure that the results of the tariff are reasonable. And if that can be done through -- through an after the fact review where the parties implicated provide access to data and models and results that allow for a thorough examination of the results that can then be presented to the Board, presented to

stakeholders, interested stakeholders to ensure that the results reflect the goal of the tariff itself and fairness, then I think that that's one way to go.

Of course, you could put -- I don't see any reason you couldn't file -- have the protocols be part of the review or at least aspects of the protocols, but we haven't given evidence on that. And I -- and I don't think -- I think it does get to a legal question about what is -- what is appropriate for Board review and approval and what is more of an operating protocol that maybe doesn't need to be reviewed and approved.

Q. And sorry, when you're saying the protocols, I assume what you're referring to is the operating procedures that were provided in response to one of IG IRs by NSPI and it's in draft form currently. Is that what you're referring to?

A. (Musco) That's right. That's right. Sorry for speaking over you.

Yeah. That's right. And I've been

using protocols and operating procedures interchangeably.

MS. RUDDERHAM: Okay. Mr. Chair, I'm cognizant that it's 3:30. I'm not sure if you wanted to do an afternoon break or if we should just truck right through. I was just about to change subjects.

THE CHAIR: So you're going to be a little bit still?

MS. RUDDERHAM: Not too, too much longer now.

THE CHAIR: Okay. We'll take our break, then.

MS. RUDDERHAM: Okay. Thanks.

THE CHAIR: We'll come back at quarter to 4:00.

--- Upon recessing at 3:30 p.m.

--- Upon resuming

VINCENT MUSCO, Resumed

COLLIN CAIN, Resumed

THE CHAIR: Okay. I think everyone's back, so whenever you're ready to go.

MS. RUDDERHAM: Thank you, Mr. Chair.

CROSS-EXAMINAION BY MS. RUDDERHAM (cont'd)

Q. So my next line of questioning is doing a comparison or trying to understand more the estimated costs -- or, sorry, the estimated benefit of load shifting. I assume this is directed to Mr. Musco.

A. (Musco) Yes.

Q. Okay. So just to confirm, NSPI's evidence in this proceeding suggests that a fully optimized estimate of benefits for PHP show -- lift load shifting is between 7 million and 11 million for 2027; correct?

A. (Musco) I believe you've got that right. It was an estimate Nova Scotia Power prepared and, unfortunately, no longer has access to via the cyber incident. But it -- that -- my understanding is that was premised on fully optimized or fully levelized load for that year.

Q. And I assume, Mr. Musco, you've reviewed the response to Synapse IR-16, which is -- it's a confidential attachment that outlines various scenarios that is the premise of that 7 to 11 million.

Have you reviewed that?

A. (Musco) Yes.

Q. Okay. And I know it's confidential and we're not going to bring it up, but just -- just a broad understanding of what that is.

What that document shows for 2027 is about -- it's 24 scenarios of what that benefit could be; correct?

A. (Musco) I believe that's correct. Yes.

Q. And then what that 7 to 11 million is, is the P10 or P90 of that -- of those values; correct?

A. (Musco) That's my understanding, yes.

Q. Okay. And now I know that the

evidence suggests that -- or NSPI's evidence suggests that the actual benefit will be about half of that, so between three and a half to 5.5 million. That's your understanding as well, correct?

A. (Musco) Yes, I believe that's their evidence.

Q. Now, in looking at that spreadsheet and those values that have been provided from the various scenarios, can you explain why it would be half of those values?

A. (Musco) No, I cannot. But -- no, I cannot.

Q. Why not?

A. (Musco) Well, again, I don't know that they, Nova Scotia Power, provided the entirety of that analysis due to the cyber event. I don't think that was provided in the referenced IR.

Q. No. And so the evidence that's on the record, does it look, in your opinion, more likely that

the benefit would be between 7 and 11 million, or would it be between three and a half to 5.5 million?

A. (Musco) We have not put forth an opinion on that, on that particular question. I know we quoted Nova Scotia Power's evidence on that -- on that point.

We were trying to note the materiality of this issue, but we did not put forth an assessment of that -- of those numbers.

Q. Okay. And so Bates White doesn't have an opinion or an analysis on what you would view as the most likely or more likely load shifting benefit for 2027.

A. (Musco) That's correct.

Q. Okay. Now, we've spoken about your involvement with the FAM and you've also been involved with the review of the ELIADC; correct?

A. (Musco) Yes.

Q. Okay. Now, in Bates White's

experience over the last six years with the ELIADC, has there -- has there ever been a benefit for load shifting under the ELIADC in the range of 7 to 11 million?

A. (Musco) I don't recall a number reaching that value, no. And in most cases, the annual calculated load shifting benefit -- well, I won't say in most cases. I believe in multiple cases it's been -- it's actually been negative in some instances. And again, that -- as we've explained in other formats, is due in part to some of the challenges in fuel pricing that drove some of those results.

Q. And sorry, in the other formats, I assume -- are you referring to a specific proceeding or what are you -- what are you referring to?

A. (Musco) I would be referring to FAM Audits.

Q. Okay.

A. (Musco) And potentially any submissions we've made in response to annual ELIADC

reports. But subject to check, I'm generally referring to our writings on the issue in that -- in that broad sense.

Q. Okay. And when you said due in part to challenges in fuel pricing, what are you referring to? Are you referring to the prior use of forward replacement costs or something else?

A. (Musco) Largely that issue, that the -- that fuel pricing can skew the results and mask the actual benefits of ADC.

Q. And that concern, then, would that still exist under the proposed ELID?

A. (Musco) Yeah, I think that it gets back to what I was discussing earlier, that Nova Scotia Power's proposal to continue to -- to use forward replacement costs in their after the fact calculation is logical though it does, in our view, still have, in limited circumstances, the risk of distortion from volatile fuel pricing.

Q. So in the past, if it's resulted

in, I think you've referred to as negative benefits or fewer benefits or less value, I guess, why would it result in increased benefits under the ELID or increased credits?

A. (Musco) Sorry. What do you -- Ms. Rudderham, you what do you mean by "it"?

Q. So I'm just trying to understand. I think you've said that under the ELIADC the benefit had not reached that value between 7 and 11 million. And I believe your evidence was that in some instances it was negative and I had asked why. And you had said that there were in other formats, you'd explain this, and it had to do with challenges in fuel pricing.

And then I had said, okay, well, does those still exist? And you said, well, they're using forward replacement costs. So you say it's logical, but there's a risk of distortion.

Wouldn't that risk be that the benefits are -- like it's not high enough? I just -- I just don't know why that would result in an increased calculation of

benefits for load shifting under the ELID.

A. (Musco) So you're asking how the forward replacement distortion issue could impact the calculation of the ELID's proposed DR credit?

Q. Well, first, does it? Would it?

A. (Musco) I think that's my point. It could in limited circumstances. That risk, in our view, still exists.

Q. And that would result in a higher benefit under the DR credit?

A. (Musco) It could be higher or lower. It depends on -- it depends on whether PHP is -- depends on what PHP's load is doing relative to the calculated levelized -- the CBL.

Q. Okay. And can you explain this for me? Where the ELIADC under the last six years, it's not reached benefits of load shifting in the range of 7 to 11, why would the range reach 7 to 11 for load shifting in 2027 under the ELID?

What's the difference? Why would it be so much higher?

A. (Musco) Well, again, I -- so I think it's important to make a couple points here.

First, they are different tariffs. Quite different. And the results can differ accordingly.

Second, you know, this is a -- this is Nova Scotia Power's analysis that they put forth that we did not -- as we've established, we did not provide evidence on the specifics of those calculations and how they -- how they were derived.

So I can't -- I can't answer for you why Nova Scotia Power's analysis results in 7 to 11 million, unfortunately.

Q. I completely understand. I get that.

I guess in Bates White's opinion, based on all the evidence that they've reviewed, is it likely that with the tariff as drafted, it's going to result in an

increase of load shifting benefits than has been in place under the ELIADC?

A. (Musco) I don't believe we have a basis to opine on that, and I don't believe we have opined on that. And so I don't have an affirmative opinion on that.

Q. Okay. And you can confirm under the ELIADC the benefit was shared.

A. (Musco) Yes.

Q. And it's 75 percent going to FAM customers, 25 percent going to PHP; correct?

A. (Musco) That's my understanding. Yes.

Q. And here the full -- the full value of the benefits, whatever they may be, would go to PHP; correct?

A. (Musco) Of the DR credit, yes.

Q. Yeah. Now, does Bates White have an opinion with respect to whether the benefit should be

shared and, if it should be shared, what that percentage would be?

A. (Musco) So we did not suggest a sharing mechanism. We did in a response, I believe, to the Industrial Group respond -- confirm that a sharing mechanism can have a material impact on the overall process. It certainly is a way to -- if you're -- to change the balance, so to speak.

I think ideally you would get it -- you'd get it right and you'd get it such that, you know, if PHP is providing that demonstrable benefit that they can enjoy the full value of that benefit. To the -- you know, as soon as you start to have concerns about the accuracy of the -- of that calculation, then, you know, ideally you would -- in an ideal world, you fix the calculation before you go to other sort of mitigating approaches.

Q. Okay. So it sounds like you're -- you agree with the evidence that Mr. Bowman just gave that if there -- if you can show demonstrative benefit, then it

should be 100 percent to PHP but where there's concerns, that's where the benefit sharing would come in?

A. (Musco) Not quite. The first portion, yes, but ---

Q. Okay.

A. (Musco) But I do acknowledge that a sharing mechanism is a way to change the balance of an outcome. But ideally, it would be addressed through, you know, ensuring that the mechanism is accurately calculating the DR credit.

Q. And where the full methodology that's going to be used for calculating the DR benefits not before the Board currently, is Bates White, I guess, confident that it -- that it should be 100 percent allocated to PHP?

A. (Musco) Again, we've raised concerns with the calculation of the DR -- excuse me, DR credit and -- in our evidence and we did not propose a sharing mechanism. Our focus has been to assist the Board

with an understanding of our view of the DR credit and to assist in ensuring that what's approved -- you know, the tariff that ultimately is approved for PHP as a customer is reasonable, including any DR credit that's -- that it contains.

Q. Yeah. And I think that Bates White's opinion, then, is -- or recommendation is to not approve the DR credit or the DR calculation portion of this tariff as currently proposed. Is that right?

A. (Musco) Correct.

Q. So I guess what are the options to the Board to address some of your concerns -- if they do approve the DR rather than reject it entirely, what are options to mitigate some of those risks you've raised?

A. (Musco) Well, I think, again, there has to be confidence that the mechanism will recognize the value of any dispatchability provided without resulting in payment for credit for the incidental load changes -- changes in load that have nothing to do with

dispatchability. And you know, there is quite a bit of this process that is contained in those -- the operating procedures and the hearing has done a good job of teasing out some of that information, which I think is a good thing and helps everyone understand how this will work.

And as I said earlier, the -- you know, it is possible that this could be -- this process could be verified after the fact with proper access to data and cooperation from relevant parties. But there's still that uncertainty that's inherent in this DR credit and, you know, I think this hearing has gone a long way into -- in advancing the record. But yeah, there still needs to be that recognition and assurance that these -- that the DR credit results will be, you know, thoroughly reviewed and subject to revision if the adjustments made were not justified or reasonable.

Q. And I assume that review after the fact, are you referring to a FAM Audit?

A. (Musco) That is one avenue. I'm

not saying that's necessarily the avenue, but that is one potential audit -- one potential avenue given that it impacts FAM costs.

Q. Do you have any other after the fact reviews you're thinking of other than the FAM Audit or a totally separate process is what you're envisioning?

A. (Musco) I'm just trying not to be needlessly prescriptive. Really, you know, to me, logically, the FAM Audit would -- it could fit there. But at the same time, it could be a totally separate process that looks solely at this information and focuses on it.

As long as it gets -- you know, it accomplishes what I've -- what I laid out a moment ago, I think either approach could work.

Q. And in this after the fact review, would the cause code tracking for load changes to distinguish between dispatchable directions or operational decisions, would that be one way of reviewing or verifying the load shifting benefit?

A. (Musco) That would seem to be relevant information, you know, to -- yeah. It would seem to be relevant information.

Q. So I apologize. I didn't mean to cut you off there.

A. (Musco) Yeah. I was just finishing my thought that the cause code data would be likely to be relevant information in that after the fact review.

Q. And you heard PHP's evidence that they do not view cause code tracking as necessary any more. Did you hear that?

A. (Musco) I believe so, subject to check of the of the hearing. I don't recall who exactly said that, but that sounds right.

Q. And I assume, then, with this after the fact tracking you disagree that cause code tracking should be removed from this process?

A. (Musco) Yeah, I think that, you

know, the nature of the cause code tracking changes as you go from ELIADC to ELID -- so there was a reasonable question about why you would continue to track cause codes if they no longer factor into the financial outcomes for customer, PHP. But I think the answer was given by the panel, the Nova Scotia panel -- Nova Scotia Power panel that the idea is to maintain some semblance of transparency and insight into the operating year so -- which is a laudable goal in and of itself.

To the extent that an after the fact review is approved as part of this process that, you know, tracking -- some sort of tracking of the final -- you know, the schedules that are developed and sort of the final schedule and any deviations from those schedules by PHP would seem to be relevant to that overall process.

Q. And I assume you've been here when both the NSP panel and the PHP panel were walked through the operating procedures in which they went over the various cause codes, correct?

A. (Musco) Yes.

Q. And under the ELID, there's now proposed to be only three cause codes which would relate to variations proposed coming from PHP, whereas under the previous ELIADC there would have been five cause codes. Correct?

A. (Musco) Yes.

Q. Now, does Bates White in this potential after the fact review -- do you have an opinion in respect of what cause code should be required? Should it just relate to when PHP deviates or PHP proposed changes or should it include both sides?

A. (Musco) I would say that I -- I don't have an immediate recommendation on that only -- and I just want to be careful that -- you know, I don't know that this has been discussed with the other panels, this particular proposal.

So it would seem to me that the most important ones to capture are the deviations that are

driven by Port Hawkesbury Paper which is -- which, you know, the -- because of equipment failure or because of their own decision to generate or to consume at their own discretion.

There's a -- there are three other codes, of course. Two are a system operator initiated up or down dispatch. That's useful as well. That's a deviation that -- where PHP is doing what it's asked in short order which has benefits. So, you know, you'd want to understand those results, those instances as well.

So yeah, I guess -- you know, all five would remain relevant to the overall picture. I just -- I don't have a strong -- I don't want to leave you with the impression that -- and you know, some subset are necessary and others aren't. I think it should be considered as part of that overall process.

Q. No, I appreciate that.

And these ccause codes and the procedures for how the DR, the ADC are done are captured in

the operating procedures; correct?

A. (Musco) Yes.

Q. And the operating procedures would have the definitions or the mechanics for how the dispatch or demand response or the CBL calculations operate; correct?

A. (Musco) I believe so, yes. I don't want to preclude that they'd also be addressed as well in the tariff, to some degree, but yes, those would be in the operating procedures.

Q. You'd agree that the operating procedures are relevant to how the DR credit or the CBL is going to be calculated in practice.

A. (Musco) Yes.

Q. Okay. And would you agree that the operating procedures would be critical for understanding whether the DR is properly measuring benefits or not?

A. (Musco) Can you clarify the

question? I'm not sure I follow.

Q. First, NSPI's position is that the operating procedures don't need to be reviewed or approved by the Board; correct?

A. (Musco) That's my understanding.

Q. Would you agree that the operating procedures themselves that have the definitions, mechanics and are relevant to the DR credit or the CBL and how those are calculated, are important for understanding whether the DR at the end of the day is properly measuring load shifting benefits?

A. (Musco) Yeah, I suppose it depends because if there's an after the fact review that is assessing that very question knowing what -- knowing in advance via the operating procedures what -- how exactly it'll work may not be 100 percent necessary to doing that after the fact review.

But it's -- certainly the operating procedures contain language and concepts that are relevant

to that calculation.

Q. And I assume if there's -- if there's no after the fact review, it would be even more important to have the operating procedures reviewed and approved by the Board?

A. (Musco) Well, again, I'm unfortunately staying away from the legal question of whether it should be approved or not. But I will say that without that after the fact review, it does become -- the risk and uncertainty certainly goes up in terms of the results and the potential impact, if there's no way after the fact to reconcile any results that are unreasonable.

Q. And the way the DR mechanism measures benefits directly impacts what's paid by other FAM customers; correct?

A. (Musco) Yeah. Again, subject to what -- our earlier discussion about not knowing exactly how the DR credit is going to be recovered from other customers and credited to PHP, the specifics there. But

yes, the answer is yes.

Q. Yeah. So the distinction you're making just there is you're not sure how it's going to be credited, but the understanding is whatever the load shifting benefit is, is going to be funded by other FAM customers.

A. (Musco) That's my understanding.

Q. Okay. Just one moment to confer.

Just one -- well, maybe two clarification points.

You had indicated that you'd want to have confidence about the reason for the dispatchability in order to verify the DR credit, to make sure that it's reasonable and accurate for benefits. Is that kind of a fair summary of what your evidence was?

A. (Musco) Reasonably. Yes.

Q. Okay. And to have that confidence, I assume that's what ties back to those cause codes. In order to have confidence that the reason for the

dispatch load would relate to what those cause code records would say. Is that fair?

Q. Well, I wouldn't -- I wouldn't tie the entirety of that confidence to the tracking of cause codes. And the codes themselves, I mean, if there's an after the fact process where there's going to be a review of the information, those cause codes, as I said, would be part of that process and relevant to that process to understand what the final schedules were, what went into those final schedules and then any deviations from those schedules. And so the cause codes could be part of it. But I wouldn't tie the entirety of that confidence to cause code tracking.

Q. Is -- what else would you need to establish that confidence, I guess?

A. (Musco) Again, it would be -- it'd be an understanding of how Nova Scotia Power went about the calculation of the final DR credit, including any discretionary revisions that they made for, quote unquote,

other factors, which is language from the tariff as well as how they went about the randomization process for the outage days.

Q. And I just want to follow up on one thing that you had indicated when Board counsel was originally introducing you. You had identified areas of additional information that would have helped on the record that have come up since you filed your evidence.

Can you clarify or explain what you were referring to?

A. (Musco) Primarily I was referring to the issue of forward replacement costs.

Q. Okay. Thanks.

Those are all my questions. Thank you, Mr. Musco and Mr. Cain.

MS. RUDDERHAM: Thanks, Mr. Chair.

THE CHAIR: Thank you.

Port Hawkesbury Paper.

CROSS-EXAMINATION BY MR. MacDOUGALL

Q. Good afternoon, gentlemen.

A. (Musco) Good afternoon.

A. (Cain) Good afternoon.

Q. If we could pull up Exhibit N-20. Bates White's evidence and go to page 12, Lines 18 to 15.

Lines 8 to 15. I'm sorry.

And gentlemen, here you say:

> The concept of a customer charge is appropriate. NSPI identifies the myriad tasks involved in administering the ELID tariff as proposed. This includes considerable interaction between NSP personnel and PHP in matters of system planning and forecasting, iterative scheduling and dispatch and reporting. NSP also must contribute to the development of operating procedures to govern the day-to-day interactions with PHP and administration of the ELID tariff, an important step to encourage efficient and effective operational outcomes. These are all incremental costs driven solely by PHP and the administration of the ELID tariff and should be recovered from PHP, as NSP proposes to do.

And that remains your testimony today?

A. (Musco) Yes.

Q. Would you agree that the explanation you gave there, those myriad tasks involved in administering the tariff are principally, if not solely, associated with the DR aspect of the tariff?

A. (Musco) I would say that a material portion of what's described is tied to the DR credit. There are some aspects that wouldn't be and are uncertain in their scope, so -- but I would say a material amount is tied to the DR credit.

Q. Okay. Thank you.

And if Port Hawkesbury Paper wasn't on the DR rider, a lot of those activities would go away; correct?

A. (Musco) I suspect some would. There may still be -- given PHP's status as the largest customer on Nova Scotia Power's system and there still could be interactions that fit under some of these descriptions, but I would expect that some aspect of this

would not be needed.

Q. Okay. And if PHP wasn't on the DR rider and wasn't priority interruptible, they would be -- even though possibly in a class of their own, they would then be quite similar to an LIIR customer in that they would have a tariff and the interruptible rider and that's how they would interact with Nova Scotia Power; correct?

A. (Musco) Well, I mean, we're -- it's a little hypothetical in that I don't know that it's been established what would happen absent the approval and effectiveness of the ELID tariff regime. But -- and, you know, if they would -- what sort of customer NSP would be and -- but granting your hypothetical that they would become a LIIR customer with no dispatchability, I -- again, I would agree that there would be -- some of these described processes would not be needed or would be reduced in their volume.

Q. Okay. And to your recollection, do you know whether the LIIR rate has a customer charge or

not?

A. (Musco) I don't believe it does, but that's subject to check.

Q. Okay, great. Thank you.

Subject to check, the LIIR does not have a customer charge, in your view.

Mr. Musco, I think it's you for this. I'm just going to try and get one other topic cleared up a bit with respect to the DR.

There were references throughout some of your earlier discussions about payments, but is it fair to say that if the DR operates and Port Hawkesbury Paper moves its load to reduce fuel costs for the utility that Port Hawkesbury Paper gets a credit against its bill, essentially? It's credited for the savings in the fuel costs or in the variable energy costs.

A. (Musco) Yes.

Q. Okay. And the concept is that other customers are held harmless because they would have

had their rates set on there being a flat load, but an adjustment is made to put them back into the same place as if NSP -- as if PHP didn't shift its load.

A. (Musco) You're describing how it's -- how the tariff's been proposed and functions, yes.

Q. Correct. So that's how it -- it's proposed to operate so other customers would not be paying for the credit that PHP receives. They would be held harmless.

A. (Musco) Well -- so first of all, and I think you made this distinction at the beginning, but this is verifiable dispatchability benefits.

Q. Correct.

A. (Musco) I think you made that. So yes, in that sense.

And yes, you're right. But that -- it's still going to be -- show up as a, quote unquote, charge to anyone who's responsible for paying for -- accounting for the credit that's going on PHP's bill.

Q. Sure. There's an adjustment put in place, but the customers are held harmless -- harmless for what they would otherwise pay if PHP hadn't have activated under the DR.

A. (Musco) Again, under your premise of it being true dispatchable benefit, yes.

Q. Okay. That's great. Thank you very much. That was a very useful verification. Thank you.

MR. MacDOUGALL: Thank you, Mr. Chair.

THE CHAIR: Mr. Melanson?

MEMBER MELANSON: I have no questions.

THE CHAIR: Mr. Norwood. I think that's N-20 that's up there. I'm looking for page 16. And down at the bottom of the page, the question beginning on line 18.

QUESTIONS BY THE CHAIR

Q. And Mr. Cain, I think this might be for you.

A. (Cain) Yeah.

Q. So this -- this goes to the discussion about the production from Goose Harbour and the P50 versus the P90 level. And the evidence as I read it suggests that the P50 level might be more appropriate and I think you reiterated that again today in your oral testimony.

But then, at the end of the end of this on -- beginning around line 16, it says:

> We do not believe moving to a P50 level at 168 MW capacity would be justified in advance of actual operating performance.
>
> Continues on on the next page.

Basically performance at Goose Harbour.

> The reason for this position is that the P90 level reflected in the Cost-of-Service Study at the 130.5 MW capacity level corresponds to a capacity factor of 44%, which is relatively high even in the context of Nova Scotia's high wind potential.
>
> And so I just wanted to clarify, you

know, I guess in terms of what the what the recommendation is, if the if the energy is to be adjusted, as Port Hawkesbury Paper suggests, whether we should be looking at the P90 level at the 168 megawatts or something different based on that. If you could just sort of clarify.

A. (Cain) Sure. I appreciate the question. And I do think it zeroes in on an issue of importance.

You know, I -- as I said earlier, I think I would modify this. And I do think on balance, on further consideration and just thinking through the process and listening to the hearing that, you know, a 50 percent -- P50 level of output would be appropriate.

So let me just say that, you know, we have an undertaking to get that estimate from PHP, which is great. I think it would be -- it would fill out the record helpfully.

I guess I was a little surprised that the P90 value for the 168 megawatts wasn't higher, but I

think that that goes -- what gives me pause is that regardless of -- I mean, we're essentially taking the estimates of the engineers for the expected output.

And so we've heard from Port Hawkesbury Paper that, you know, they've got to convince lenders that this is -- they're going to be able to cover debt service, that the output of the facility is going to be at least at the P90 level the vast majority of the time. So I think that if those are the values that are appropriate in terms of the engineering of the facility, the establishment of the PSA and the expectations for the facility that we can accept that P50 is in that same category. It's the best estimate of the engineers and the developers.

And at the -- at the 168, it gives the likely capacity of the facility and it gives a symmetrical probability of being above or below in the course of a given year. And it does seem to me that it -- in the context of setting the right rate, that that symmetry is helpful. It cuts -- you know, it gives you equal

probability of being over or under and it mitigates against -- to some extent, against the other aspects of how the PSA inserts distortions into the rate setting process.

Q. My sense was, Mr. Cain, that some of your hesitation was you just really didn't believe the numbers and that you were really looking more for an operational history to be kind of the more valid indicator than the estimates.

A. (Cain) And I'll grant that I don't have a deep experience with wind generation potential in Nova Scotia so that 44 percent, just based on my experience in -- let's say in the Americas, it is high. You see higher numbers in parts of Mexico where it's very windy, but 44 percent is a pretty high capacity factor, and particularly if it's at a 90 percent likelihood.

So yes, that was my reaction to it. It just -- it seemed high, so caution seemed reasonable.

But, you know, again, if this is what's being advanced as the best available data from the

developer of the facility, I don't think it should be disregarded.

Q. Okay. And thank you. Those were all of the questions that I had.

THE CHAIR: Is there anything arising from my questions?

I'm not seeing anything.

Anything by way of redirect, Mr. Mahody?

MR. MAHODY: No, Mr. Chair. Thank you.

THE CHAIR: Okay. Mr. Musco, Mr. Cain, thank you very much for your participation in the proceeding. That end your testimony so you're free to go.

Anything else at this point?

Ms. Power, your application, I guess.

MS. POWDER: If I could just have a minute to speak with counsel on deadlines and dates.

Thanks.

(SHORT PAUSE)

MS. POWER: Mr. Chair, we have a proposal. At the end of next week on October 9th, PHP and Nova Scotia Power can file undertakings. We'll all close on Monday, October 26th and reply to closing on Monday, November the 2nd. And that's on the basis that we can expedite the transcript delivery if possible. Thank you.

THE CHAIR: Yeah, we'll certainly -- look into that and try to get it. What date were you hoping to get it for?

MS. POWER: So if it's a five to nine turnaround day, we wouldn't end up getting this transcript until October 14th so ideally, you know, by end of next week we'd have the transcripts.

THE CHAIR: Okay. All right. We should be able to -- we should be able to determine whether that's possible within the next day or so and, if not, we'll let you know and you can you can revisit dates. But I appreciate the urgency and we'll certainly do what we can to make that happen.

Anything else?

Okay. I think we're adjourned for the day. Thank you counsel. Appreciate it.

--- Upon adjourning at 4:46 p.m.

CERTIFICATE OF COURT TRANSCRIBER

I, Jacqueline Clark, hereby certify that I have transcribed the foregoing and it is a true and accurate transcript of the evidence given in this matter, M12661.



Jacqueline Clark

Dartmouth, Nova Scotia