

NOVA SCOTIA ENERGY BOARD

IN THE MATTER OF: *THE PUBLIC UTILITIES ACT*

- and -

**IN THE MATTER OF: THE FINANCING ORDERS AND SECURITIZED BONDS
REGULATIONS**

- and -

**IN THE MATTER OF: AN APPLICATION by NOVA SCOTIA POWER
INCORPORATED** for approval of a financing
order authorizing the securitization of 1
billion in costs, collected through a
Securitization Cost Recovery Rider

TRANSCRIPT

HEARD BEFORE: Nova Scotia Power and Interested Parties

PLACE HEARD: Teams Virtual Meeting

DATE: Thursday, October 15, 2026

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I N D E X O F P R O C E E D I N G S

PAGE NO.

Technical conference

1

1 **Halifax, Nova Scotia**

2 --- Upon commencing October 15, 2026 at 12:05 p.m.

3 **MR. WILLIAMS:** I think we're going to
4 get started. Apologies for the delay.

5 We'll maybe start with just doing some
6 brief intros and we'll intro from Nova Scotia Power those
7 of us that are -- maybe just the four of us that are going
8 to be speaking to things and then we'll do a bit of a roll
9 call on intros of external parties on the phone.

10 So just to start, I'll introduce
11 myself. Blake Williams. I'm the Vice-President of Legal
12 and Regulatory at Nova Scotia Power.

13 **MR. FLEMMING:** Good afternoon,
14 everybody. Craig Flemming, Nova Scotia Power Finance.

15 **MR. WILLETT:** Good afternoon. Michael
16 Willett, Senior Directory Regulatory.

17 **MR. HEISLER:** I'm Justin Heisler. I'm
18 VP Corporate Strategy for Emera.

19 **MR. WILLIAMS:** Thanks.

1 So now I'll turn it over briefly to
2 the -- I'll guide us through the role call on the line
3 with the parties, but before I do that, I just want to
4 make sure everyone is understanding that this is -- this
5 session is being recorded, but we also have the court
6 reporter on the line who is recording and will be
7 transcribing as per the Board's letter -- transcribing
8 this session with the intent of having that transcript put
9 on the record in this proceeding.

10 And I don't know exactly the timing of
11 that. It intends to get that up as soon as possible. If
12 it's not tomorrow, I think my understanding that would be
13 Monday of next week, but we can confirm that for
14 everybody, so manage your expectations accordingly.

15 So with that, I'll maybe just go
16 through the parties who I'm aware -- Bill, do you want to
17 start with -- Bill Mahody, those of you who are on the
18 call from the Energy Board.

19 **MR. MAHODY:** Sure, Blake. It's Bill.

1 I'm on the call, and I think there are a number of others.
2 Maybe I'd just allow Board staff and then the
3 representatives from the Board counsel consultants to
4 introduce themselves.

5 MR. WILLIAMS: Sure.

6 MS. McNAMARA: Libby McNamara is on
7 the line, and Miranda Mavhunga and Holly Chisolm are also
8 from Board staff.

9 MR. WILLIAMS: And any consultants?

10 MR. MUSCO: Yeah, this is Vincent
11 Musco from Bates White. I've got with me Karen Morgan and
12 Arjun Chadhat.

13 MR. WILLIAMS: Okay.

14 MR. COLAIACOVO: Hi, Pelino Colaiacovo
15 and Michael Saltzman are both on from Morrison Park
16 Advisors.

17 MR. WILLIAMS: All right. Thanks.

18 MS. CLEARY: Hi, this is Jane Cleary,
19 and I'm with Doane Grant Thornton.

1 **MR. WILLIAMS:** Okay. Is that it,
2 Bill?

3 **MR. MAHODY:** Those are the people I
4 was expecting, so yeah, I think we're good.

5 **MR. WILLIAMS:** Great.

6 Dave Roberts, do you want to go next
7 for the Consumer Advocate?

8 **MR. ROBERTS:** Sure. David Roberts.
9 Michael Murphy is on the line, and I just got an email
10 from Andrew McLaren and Hayitboy Mahmudov to tell me that
11 they didn't get the new link.

12 **MR. WILLIAMS:** So we'll get that to
13 them later.

14 **MR. ROBERTS:** Okay. Thank you.

15 **MR. WILLIAMS:** Melissa, Small Business
16 Advocate?

17 **MS. McADAM:** Yes, Melissa McAdam. I'm
18 joined by Rebecca Powell as well as Melissa Whitten on
19 behalf of Daymark Energy Advisors.

1 **MR. WILLIAMS:** Nancy and/or Brianne?

2 I think I saw Brianne on, at least.

3 **MS. RUBIN:** Hi. Nancy and Brianne on
4 for the Industrial Group, and we are joined by our
5 consultants Patrick Bowman and Melissa Davies.

6 **MR. WILLIAMS:** Great, thanks.
7 PHP?

8 **MR. MacDOUGALL:** Hi, David MacDougall
9 and James MacDuff.

10 **MR. MacDUFF:** Yeah. And Blake, I'm
11 also on for the Municipal Electric Utilities.

12 **MR. WILLIAMS:** That was my next
13 question. Perfect. Thanks, James.

14 Okay. Renewall?

15 **MR. ROSCOE:** Good afternoon, Blake.
16 Dan Roscoe here on behalf of Renewall.

17 **MR. WILLIAMS:** Great. Thanks, Dan.
18 And Department of Energy?

19 **MR. KAYTER:** Thomas Kayter for the

1 Department for the Department of Energy and joining me is
2 Girish Patel, engineer for the Department.

3 MR. PATEL: Good morning ,everybody.

4 MR. WILLIAMS: Thanks, guys.

5 Is there anyone who I've missed? And
6 if I have, my apologies.

7 MR. BOURNE: Blake, it's Keith Bourne
8 from the MSPML, and I'm here with the team -- Regulatory
9 Team, Dave Landrigan, Shellie Woolham and Erin Graves.

10 MR. WILLIAMS: Thanks.

11 MR. BUTLER: Good afternoon. Patrick
12 Butler representing KMK and the Assembly of Nova Scotia
13 Mi'kmaw Chiefs, along with Greg Hart.

14 MR. WILLIAMS: Great. Thanks, guys.

15 Dave, Michael, just confirming that
16 we're getting that invite over to Andrew and Hayitboy. Do
17 you want us to wait a minute before we get started?

18 MR. ROBERTS: If you wouldn't mind.

19 I asked them to confirm when they

1 receive it, and I haven't heard back from them yet.

2 MR. MURPHY: It does look like
3 Hayitboy may be on the line.

4 MR. ROBERTS: Okay. I see it, yes.

5 MR. MAHMUDOV: Yes, I'm online. I'll
6 forward it to Andrew because I'm not sure he got it.

7 MR. ROBERTS: Okay. Thank you.

8 MR. WILLIAMS: Okay. Well, I'll just
9 -- maybe I'll just get started, Dave, at a high level, and
10 I think by the time we get into anything substantive,
11 Andrew should be on.

12 So the intent today is -- it's a
13 technical conference, so the intent is to go through the
14 application and Craig and Mike and Justin have some slides
15 that they'll use to help with the understanding and help
16 walk through everyone -- help walk through the application
17 for everyone.

18 We're intending or hoping to leave a
19 significant amount of time for questions because we expect

1 there to be questions, but maybe where I'll start is just
2 with an overview of the Hearing Order, what we understand
3 the process to be and what we think the outcome would be
4 at the end of the 60 days and the process going forward
5 after that 60-day timeline that's included within the
6 Regulations.

7 So we've got a bit of a plan as to how
8 we're going to walk through everything but, as per usual,
9 there's no need to wait. If you do have questions, feel
10 free to interrupt or raise your hands and we can address
11 them on the fly or if you prefer to wait until we're at a
12 natural break, then that's also perfectly acceptable. So
13 however you prefer.

14 So it's not intended to be a sit and
15 listen type presentation, it's intended to be interactive
16 and hopefully we can answer any questions that anyone has.

17 So just to get us started, then, I
18 guess, again, the Hearing Order that the Board has issued
19 commencing with this here today, this technical

1 conference, the information requests from parties and
2 their responses from Nova Scotia Power, evidence from
3 Board counsel consultants and then written submissions
4 from the parties and reply submissions from Nova Scotia
5 Power.

6 That's obviously the formal process
7 that's been outlined by the Board but, as has been the
8 case leading up to this and as will continue to be the
9 case, from our perspective, if there are questions or
10 discussions that any of you think would be helpful outside
11 of what's outlined in the Hearing Order, then please do
12 not hesitate in the slightest to reach out to us. We're
13 more than happy to have those discussions and address
14 those questions to get you any information that may be
15 helpful and you getting a better understanding of things.

16 As I think everyone is aware at this
17 point, the Regulations provide that the Board will make a
18 decision on this application within 60 days from the
19 filing date, so we anticipate that we would then get a

1 decision at the latest kind of early or mid-December based
2 on the filing date.

3 What would be issued at that point is,
4 obviously, the financing order, and the financing order,
5 we would expect it to have conditions in there that if
6 it's approving the securitization, then it would be
7 approving it within bounds and you will all have seen in
8 Appendix B of the application that there is a sensitivity
9 analysis that dictates what the net present value or the
10 benefits for customers would be from a net present
11 perspective dependent on the bond yields that are
12 eventually obtained in the market. And so we would expect
13 the Board's decision to put essentially bookends on that
14 or a bookend as to when, from the Board's view, the
15 transaction and securitization would cease to be just and
16 reasonable or in the best interests of customers or
17 otherwise where it would cease to provide it a net present
18 value for customers provided that when we go ---

19 MS. RUBIN: Blake, sorry to interject.

1 You're really choppy. You're kind of going in and out and
2 I don't know if it's you're leaning back or turning back
3 around, but if you could position yourself closer to the
4 mic it would be helpful.

5 **MR. WILLIAMS:** Sure. I'm not entirely
6 clear where the mics are, Nancy, so I'll try to project a
7 little bit more.

8 Is this better?

9 **MS. RUBIN:** Yeah, I think it's --
10 you're sort of turning one way, then the other and then
11 leaning forward and leaning back and it's kind of choppy
12 in and out. I can generally make it out ,but it's not
13 particularly clear.

14 **MR. WILLIAMS:** No, that's -- thank
15 you. I'll try to remain stationary.

16 So as I was saying, the expectation
17 was -- would be that the financing order as issued by the
18 Board or as approved by the Board would have those types
19 of parameters in there that if and when we go to market,

1 we would be required to only go to market provided we can
2 get a bond yield that fits within those parameters. And
3 then, as the Regulations stipulate, once the assets
4 transfer to the LP or the earlier of that or the bonds are
5 issued, then the financing order is irrevocable.

6 So that means at that point we are
7 going forward with this because we can go to market and
8 find bond yields within the parameters that's established
9 by the Board.

10 As I think we were clear in the
11 application, the 60 days would -- in conforming with the
12 Regulations, the 60 days requires a decision on this, but
13 there is the ability for the Board to approve the --
14 effectively approve the securitization rider on an interim
15 basis. So what those rate impacts that flow from the
16 securitization may be for customers would be approved on a
17 -- I'll stop looking at the camera.

18 So it's anticipated that the Board
19 would approve the rate impacts for customers on an interim

1 basis and the benefit of that, obviously, is that it
2 allows for a further regulatory process to play out that
3 would make the final determination as to what we split of
4 the securitized surcharge would be as between the customer
5 classes.

6 So again, I think it's important for
7 everyone to understand that these 60 days, the process is
8 intended to be approval of the transaction and interim
9 approval of the rate impacts as a result of the
10 transaction with a further regulatory process to play out.
11 And that regulatory process is not set out in the Hearing
12 Order, which is a bit of a difference from what we would
13 have seen in the 500 million LFG filing, where there was
14 kind of established two regulatory processes in the
15 original hearing order.

16 The first dealt with the NSPML portion
17 of that application, which was the transaction for the
18 \$500 million Federal Loan Guarantee, and the second
19 portion was for the AA/BA Rider, which is the Nova Scotia

1 Power portion of that filing. And that played out over a
2 longer period of time.

3 Circumstances are different in that
4 there's just the one applicant here, but we would expect
5 the process to eventually play out in much the same way.
6 But obviously that is the Board's prerogative, or the
7 Board's decision, but what I just described would be
8 consistent with what we applied for, which is also
9 consistent with the Regulations themselves.

10 Is there -- are there any questions
11 about any of that?

12 **NANCY RUBIN:** Blake, just to confirm,
13 all issues with respect to allocation remain open and
14 you're only looking for the part one, the approval of the
15 transaction, here?

16 **MR. WILLIAMS:** That's right. So the
17 approval of the transaction to go issue the bonds. The
18 rates as they're applied for would go into effect January
19 1st, 2027, but they would be going in on an interim basis

1 and they would be trued-up subject to all aspects of the
2 allocation between customer classes.

3 As well, they also would have the
4 potential to be trued up if the bond yield is different
5 than what's assumed in the application as well as trued up
6 for financing costs as those evolve over time as well.

7 So those are kind of the aspects of
8 this that are to be trued up, but to be direct in
9 responding to your question, yes, it would be our
10 expectation that all aspects of the allocation would
11 remain subject to further Board approval, assuming the
12 Board does approve on an interim basis.

13 Okay. Anything else from --

14 **MS. RUBIN:** Sorry, just one follow-up
15 on that.

16 Process-wise, how do you see the next
17 phase of this playing out? Or maybe that's a discussion
18 that needs to be had with Bill.

19 **MR. WILLIAMS:** Yeah, I think -- so I

1 don't want to really -- I'm already probably at the point
2 where -- I don't want to speak for the Board at all in
3 that respect. So Bill, if you want to provide any input?

4 But from our perspective, Nancy, I
5 think what that process looks like is perhaps guided by
6 the parties. I don't know if the Board intends to seek
7 input on that or if they have a sense of what they want to
8 do, but we have no preconceived notion of what that
9 regulatory process would like.

10 We understand that there are likely to
11 be questions and that customer representatives likely
12 would want to have further opportunities to ask questions
13 and provide evidence.

14 I don't know, Bill, if you have
15 anything to add to that.

16 **MR. MAHODY:** I don't, Blake. You
17 know, obviously, it's -- the Application's just been
18 filed. I think you've properly identified the number of
19 issues that are in the Board's hands. And I think they

1 all have to be sorted as part of this process and whatever
2 subsequent processes might fall out of it.

3 **MS. RUBIN:** Sorry, just one more
4 clarifying question then.

5 So in the Board's schedule, there's
6 only provision for Board counsel consultants to file
7 evidence. So to the extent any of the intervenors have
8 evidence, there's no provision in this part of your
9 application for intervenor evidence and that would be
10 preserved for the second -- part two of this?

11 **MR. MAHODY:** So Nancy, it's Bill.
12 Just in relation to the Board order, if -- certainly if
13 any party is looking for the ability to file evidence,
14 that would be a matter of making that request to the Board
15 for that date to, you know, potentially apply to any
16 intervenor evidence that's going to be filed as well. But
17 you're appropriately identified what the Board order says
18 at the current state.

19 But if there's a change requested to

1 that, I'm sure the Board will consider that.

2 MS. RUBIN: It was just more if the
3 only aspect of the Application -- the intervenor's expert
4 evidence related to allocation and the rider, can we
5 safely assume we don't need to make the request to file
6 evidence because there will be a supplementary process for
7 that, or should we assume we need to file that evidence
8 with leave of the Board in this proceeding?

9 MR. MAHODY: Well, I don't --
10 obviously, I can't speak for the Board in relation to the
11 Application that's currently before it and I would think
12 that if they're -- if decisions are going to be made based
13 on scope of participation, they should probably be made by
14 way of putting something on the record as far as either a
15 request to clarify so that you've got an accurate
16 understanding of what the expectation is here or not, but
17 I just -- I'm hesitant to kind of -- at this stage, I
18 can't give you any type of clear answer as to whether or
19 not you've got it bang on or not.

1 **MR. WILLIAMS:** Nancy, if I may, I
2 think what we had envisioned was -- and that's why I
3 referenced the 500 FLG. We kind of envisioned a process
4 similar to that.

5 So you know, whether you want to write
6 to the Board or not to seek the clarity that you're fairly
7 asking for is up to you, but when you look at that Hearing
8 Order, and I have it in front of me here, it had the
9 process on the transaction itself.

10 So again, that was the NSPML
11 application and it was dealt with in much the same way
12 that this is being dealt with, albeit even on a quicker
13 timeline, within 30 days. And then it had a further
14 process that dealt with the FAM AA/BA, which was Nova
15 Scotia Power's application. And that played out over the
16 following months.

17 I think it then went from December
18 into January where the original process was through
19 October. And then it had a deadline for intervenors or

1 Board counsel to seek leave to file evidence.

2 So I think what I would suggest is a
3 process like that where there is also another opportunity
4 to ask IRs, and that's the same as the process that was
5 followed with the FLG where the second aspect of that FLG
6 process had IRs and then had the deadline to seek leave
7 and then have written closing and reply submissions.

8 I think it would be helpful to have
9 something like that as it relates to the cost-of-service
10 aspects of this filing because if we get into asking IRs
11 on the cost-of-service within the current process as it's
12 laid out, then I feel that we are going to get bogged down
13 within the 60 days. And to turn around IRs on the
14 transaction and the cost-of-service within a week, as the
15 current schedule would dictate, is likely not possible,
16 given I assume what the number of questions in issue may
17 be from customers on the cost-of-service.

18 So I think the most efficient way to
19 go about this would be very similar to what was done with

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1 the FLG application and the processes that followed.

2 MS. RUBIN: I think that ---

3 MR. MacDOUGALL: Blake, it's David ---

4 MS. RUBIN: Oh, sorry. Go ahead,
5 David.

6 MR. MacDOUGALL: Yeah, it's David
7 MacDougall here. I just want -- I think we do need a
8 little more clarity.

9 So for example, in this application,
10 you have broken down, for example, buckets of which
11 parties are responsible for recovery of which asset
12 classes. And our understanding is that that would be
13 dealt with. You have applied now and that would be agreed
14 to.

15 Clearly PHP, in the \$500 million FLG
16 piece, was disappointed that after they had agreed with it
17 occurring, in the subsequent process something arose that
18 they did not anticipate whatsoever. So we have to make
19 sure that this is the process to deal with those buckets,

1 at a minimum, because we won't be in a position to approve
2 the -- or to give any positive comments on the
3 securitization if we then have to potentially have a fight
4 over how those dollars are allocated later on.

5 That's the exact negative situation
6 that occurred in the process that you're suggesting is a
7 template for this process.

8 So certainly from the PHP perspective,
9 we need to know that we're not opening up issues such as
10 these are the buckets of funds that are going to the
11 various stakeholder -- customer representatives or
12 customer classes, although there may be some further
13 debate on that allocation, but not which buckets -- which
14 customer classes would subsequently be responsible for
15 because it's clear from this application, or at least we
16 believe it is clear, and it should be, that PHP isn't
17 responsible for FAM charges that they didn't create. But
18 we do not want to have that fight again, and if there is
19 such an issue to be raised it needs to be dealt with in

1 this proceeding not, in any other proceeding.

2 MR. WILLIAMS: Yeah. And so I get it.
3 Like I'm hanging up a little bit because we're talking
4 about Board process, and obviously that's not our purview.
5 I'm just making suggestions as to how this would go.

6 And I think to get to a little bit of
7 what you were asking, certainly our expectation would be
8 that the buckets or whatever the securitized costs would
9 be are being affirmed as part of this -- this component in
10 the application. Who's responsible for those buckets and
11 how much responsibility they may have would be something
12 that would be determined as part of the cost-of-service
13 component.

14 But we would absolutely need to
15 determine what those buckets are at the highest level as
16 part of the ---

17 MR. MacDOUGALL: Yeah. Well, that may
18 be problematic if we can't have some determination of
19 knowing who is responsible at least for the buckets, not

1 then the cost-of-service within the buckets because that
2 would leave us in a position where we may be approving
3 something that we then find out we wouldn't have supported
4 because we wouldn't have been responsible for those costs
5 had the securitization not been approved. So that's
6 pretty fundamental for Port Hawkesbury Paper.

7 **MR. WILLIAMS:** So yeah, I mean, I
8 don't want to take on the role of the Board here because
9 it's our application but it's the Board process so -- and
10 what they determine and when is ultimately up to them.

11 **MS. RUBIN:** Just to kind of wrap this
12 up, I think someone -- I do agree we need clarity from the
13 Board on the process and I don't know, Blake, if you
14 intend to do that or you want one of us to do that, or how
15 we should bring this forward.

16 **MR. WILLIAMS:** Yeah. So I mean, we're
17 happy to work with any and all of you as is going to be
18 most efficient. By no means would we say no, you're on
19 your own, but I also recognize there's a number of

1 different parties on here so if we can come to some sort
2 of consensus on what the approach would be or if we want
3 to just -- or you all just want to write and provide your
4 thoughts or concerns with the Board during the process,
5 then that's certainly up to you as well.

6 But I'm mindful of the fact that we're
7 working with a very limited timeline and we need to be
8 clear on what the process is or is not at this point. So
9 happy to assist, but ultimately, that's really all we can
10 do. We can't make the decision for the Board.

11 So not much of an answer, maybe,
12 Nancy. I'm not trying to be unhelpful, but also would
13 appreciate hearing from others on what their thoughts
14 might be on how to approach this or yourself on what your
15 preference might be.

16 **MS. RUBIN:** I don't -- we're happy to
17 write to the Board just say, look, this issue arose at the
18 outset of the technical conference and we just want some
19 clarity on the process and what's at issue and then the

1 subsequent process for purposes of knowing whether we need
2 to file evidence in this proceeding or in a future
3 proceeding and what the issues are and then, if the Board
4 wants to hear from other parties, which I assume it will,
5 I'm sure they'll respond.

6 **MR. WILLIAMS:** Yeah. And I think that
7 one of the benefits of having this transcribed, you know,
8 it should be clear for the Board what some of these issues
9 and concerns are just even based on the transcript itself.

10 **MR. MAHODY:** Yes, I think it will be -
11 - it's Bill.

12 I think it will be a helpful use of
13 the transcript, but I guess given the compressed timeline
14 to a decision point here, you know, if this is a live
15 request the earliest that it could be placed on the
16 record, you know, if it could be a letter that could come
17 very soon, I think that would be helpful given the very
18 tight timelines that the Board's working under here.

19 **MS. RUBIN:** We can send it

1 immediately.

2 **MR. WILLIAMS:** Okay. Any other
3 questions on what was intended to be the intro?

4 Okay. I'm going to turn it over to
5 Craig and he'll start walking us through the application.

6 But again, this is a great discussion,
7 and I would encourage you all if you have questions to
8 just raise them on the fly.

9 **MR. FLEMMING:** Okay. Good afternoon,
10 everybody. So I'm going to start with an overview of the
11 securitized costs, and these are the costs that we are
12 proposing to include in securitization bond transaction.

13 The first and largest bucket that we
14 have included are the thermal assets, and this would be
15 the thermal assets -- the remaining current tariff net
16 book value as of December 31st of 2025. This was the
17 approach that was included and considered as part of the
18 General Rate Application, and so the assets that are
19 included in that are the same assets that were

1 contemplated to be included at that time. That includes
2 not only the net book value but also deferred financing
3 costs for a period from the period of May when the General
4 Rate Application was approved to November. And the reason
5 we cut that off in November is because, under the current
6 timeline, we would expect that the financing transaction,
7 the bond issuance, would occur in December and, therefore,
8 there would be no deferred financing costs in December of
9 this year. So only for that May to November period
10 associated with the deferred financing costs.

11 We've included as well the PHP
12 deferral. This was established as a result of the GRA
13 decision. This was the difference between non-fuel
14 revenue under PHP's current tariff and an above the line
15 tariff. And so we have included in the application a
16 breakdown in the calculation of that, and that is the
17 forecast deferral as of December 31st of this year, 2026.

18 The ISO deferral, \$20.2 million, that
19 includes the -- it includes the cost that Nova Scotia

1 Power has provided to the ISO to assist in the
2 establishment of that organization. That is an amount
3 that began with \$950,000 per month in February of this
4 year, 2026, and the amount changes in December of next
5 year -- excuse me -- of this year based upon the ISO's
6 application that is before the Board. So that is the
7 \$20.2 million for the ISO deferral.

8 And then fuel and purchase power. So
9 this represents unrecovered fuel costs, both fuel costs
10 that have been under-recovered to date and are currently
11 in the FAM as well as future fuel and purchase power
12 costs. And I'll speak about that in a little bit more
13 detail when we get to that slide.

14 So the total bond issuance is for \$1
15 billion even. We have estimated, based upon input from
16 our financial advisors on the transaction, that there will
17 be financing fees associated with issuance of the bond in
18 the amount of approximately \$12.5 million. So a bond
19 issuance of \$1 billion and net proceeds to Nova Scotia

1 Power to cover those assets in the amount of \$987.5
2 million.

3 I'll move on to talk about these
4 assets in a little bit more detail. So we'll start on the
5 next slide, please, with the thermal assets.

6 So these thermal assets these are --
7 as I mentioned, they're the same thermal assets that were
8 contemplated as part of the General Rate Application.
9 Folks who have seen our decarbonization deferral account,
10 or DDA, annual report may recognize the balances totaling
11 the total unrecovered net book value of 713 as being
12 consistent with that report.

13 So these are -- this is the net book
14 value of, again, at December 31st, 2025, the total amount
15 of unrecovered costs associated with the assets there,
16 Point Aconi, both the Trenton units and common plan, both
17 of our marine unloading facilities, the international pier
18 at Point Tupper Marine Terminal, and our steam general
19 assets.

1 So consistent with what we would have
2 proved in the DDA report, and that is along with financing
3 costs for the May to November period, as I mentioned
4 before, and that total is \$740.6 million. We only
5 included the assets up until December 31st, 2025 to be
6 consistent with what was included in our General Rate
7 Application.

8 There has been continued investment in
9 our thermal generating fleet and supporting assets, but we
10 did have -- folks may recall, we did have revenue
11 requirement included in our General Rate Application to
12 support ongoing investment. And so we did not include
13 additional book value since the end of December because we
14 already have that in rates and we're cognizant of that
15 fact.

16 We'll move on to -- yeah, we have on
17 this page both the PHP and IESO deferral. So we have
18 provided in the Appendix A the expected non-fuel revenue
19 variants for the May to December 2026 period. We provided

1 that forecast. It comes to \$12 million, along with the
2 financing expense associated with that asset gets us to a
3 total of \$12.2 million.

4 We've included the PHP deferral in the
5 proposed transaction because it facilitates the potential
6 transition of PHP to an above-the-line tariff that can
7 provide increased contribution towards fixed costs for
8 customers on a go-forward basis and assists in the
9 introduction of PHP's wind resource to the Nova Scotia
10 system.

11 This is a significant generation
12 asset. It will provide a material amount of wind
13 generation to the Nova Scotia grid in future years that we
14 expect will match or exceed the length of the proposed
15 amortization period of the underlying asset. And so for
16 that reason, we are proposing to include this in the
17 securitization transaction.

18 The IESO deferral, as I mentioned
19 before, \$950,000 a month for the period of February to

1 November of 2026, that is 10 months or \$9.5 million. And
2 then based upon the IESO's application for revenue
3 requirement, that amount goes to \$2.5 million to bring
4 them to the end of their fiscal year at the end of March
5 2027. And that would be an additional \$10.1 million,
6 along with financing expense on that deferral, brings us
7 to a total of \$20.2 million.

8 Again, these amounts represent the
9 cost to establish the IESO. And the IESO is responsible
10 for supporting resource development, energy efficiency,
11 greenhouse gas reduction objectives. And as we note in
12 the Application, the establishment of the IESO has been
13 identified by the Government in Nova Scotia as an
14 important step in continuing and completing the energy
15 transition in Nova Scotia.

16 We expect the IESO to provide value to
17 Nova Scotia Power customers and the Province over a period
18 well into the future. And due to this, we believe that
19 the costs that are assisting with the establishment of

1 this long-lived organization are appropriate to include in
2 the securitization transaction.

3 And I just included a note here.
4 We've included it in the Application as well, but I think
5 important to reiterate, both of these items, the PHP and
6 IESO deferral, they are based upon forecast future values.
7 So the \$12.2 million for the PHP deferral at the end of
8 2026 and the \$20.2 million total IESO deferral as of March
9 -- at the end of March of next year, those may not be
10 exactly as we have forecast. And so Nova Scotia Power is
11 proposing that any difference between what is included in
12 the Application and the actual balance at those dates, we
13 would balance that by -- we would balance by either
14 debiting or crediting that amount to the FAM.

15 So for example, if the total IESO
16 deferral instead was \$19.2 million, that would be an
17 additional \$1 million that would be credited to the FAM,
18 and vice versa. If it was \$21.2 million, that would be a
19 reduction in the amount that we proposed applying to fuel

1 and purchase power.

2 Hi, Libby.

3 **MS. McNAMARA:** Hi. I'm having a
4 little bit of trouble seeing the connection here with
5 these costs in the same way as the coal assets. And these
6 ones are newer, the coal assets we talked about in the
7 GRA. These ones have just come up now. But sort of all
8 three of these deferrals were really only ever intended to
9 be short term deferrals and not pushed off, you know, 30
10 years into the future.

11 So could you elaborate a little bit
12 more on if there's any additional reasoning or, you know,
13 sort of the fairness to future customers in pushing these
14 costs out that far? Including FAM -- the FAM costs.

15 **MR. FLEMMING:** So Libby, I'll start,
16 and then maybe some folks in the room have something that
17 they want to add that -- and I do have some more detailed
18 fuel costs as well in the upcoming page here.

19 But, you know, we looked at this as a

1 transaction that will benefit current and future
2 customers. And really, what we're trying to do is look at
3 the energy transition and the costs that are going to
4 benefit customers for a significant period of time.
5 That's what I was referring to when I talked about the PHP
6 deferral, the fact that that transition has the
7 opportunity to provide significant value to customers by
8 moving to an above-the-line rate as well as associated
9 with the generation asset. And with the IESO deferral,
10 the establishment -- the start-up costs associated with an
11 organization that we expect to provide a significant
12 amount of value to customers and Nova Scotians for many,
13 many years into the future. And so for customers today to
14 bear all the costs associated with that, you know, given
15 the ability to maximize customer value throughout this
16 securitization transaction, we thought it was appropriate
17 to match that value over current and future customers, or
18 to match the value, but -- the costs associated with this
19 over current and future customers.

1 Melissa?

2 **MS. DAVIES:** Yeah, hi. Good morning.

3 I'm just -- my question is with respect to the IESO
4 deferral balance on the December to March amount of 2.5
5 million a year. That's approximately, like, \$30 million a
6 year. But I understood their '26-27 full revenue
7 requirement budget to be about 15 million so I was just
8 wondering how that -- how you developed that monthly
9 number and how it compares to their budget that they
10 submitted.

11 **MR. WILLETT:** Yeah. Melissa, it's
12 Mike Willett here.

13 So those numbers are coming directly
14 from the IESO's application. So there was a little bit of
15 a catchup in the December through March...

16 **MS. DAVIES:** Sorry; you muted, I
17 think.

18 **MR. WILLETT:** Sorry. Not sure how
19 much you heard, so maybe I'll start over.

1 **MS. DAVIES:** There was a catchup from
2 December to March.

3 **MR. WILLETT:** Yeah, there was a
4 catchup from December to March. So that's coming directly
5 from the IESO's application for their revenue requirement
6 collection mechanism. So the amounts from December
7 through March are to catch up from the prior months.

8 **MS. DAVIES:** Okay. Thanks.

9 **MR. FLEMMING:** Do you have any other -
10 - no? Okay. Great.

11 We will move now to fuel and purchase
12 power. And so the total amount we were proposing to apply
13 to the fuel and purchase power is \$214.5 million. This
14 includes not only the unrecovered -- forecast unrecovered
15 FAM balance through September 30th of 2026, but also future
16 under-recoveries or forecast under-recoveries for Q4 this
17 year, as well as 2027.

18 We've also proposed an additional FAM
19 pre-payment. Part of this was, you know, around the

1 significant volatility and unexpected costs. We've seen -
2 - certainly geopolitical events has played a factor in
3 that. And also, as we note in the application, for the
4 efficiency of marketing the bonds to attain interest, and
5 therefore, the best rate possible for customers, our
6 financial advisors advised us that issuing for \$1 billion
7 round number would provide the best results.

8 And so we have provided there the
9 breakdown, again, the forecast under-recovery to September
10 30th, the forecast under-recovery of the remainder of this
11 year or next year, an additional amount of \$23.2 million.

12 The unrecovered fuel costs, as I
13 mentioned, they represent expenditures that have been
14 incurred and are expected to be incurred during the energy
15 transition period, and they're also coming about at a time
16 when we continue to operate our legacy thermal fleet while
17 construction of replacement renewable generation, energy
18 storage, the Nova Scotia to New Brunswick transmission
19 intertie and other energy transition assets is ongoing.

1 Fuel costs have been higher than
2 expected, and that's higher than expected at the time of
3 our GRA forecasting, and it has been due to unexpected
4 circumstances, including higher commodity prices, again
5 associated with geopolitical events is a driving factor,
6 as well as colder weather. And this is happening at the
7 same time as customers are seeing the impact of those
8 higher commodity prices on many other items. So that
9 includes at the gas pump, at the grocery store, for folks
10 that use home heating oil. That's just to name a few.

11 So in addition to this, Nova Scotia
12 Power continues to experience credit metrics that are
13 close to the threshold that are required to maintain its
14 current credit rating. These costs are not included in
15 the securitization transaction.

16 Nova Scotia Power would need to
17 advance an application to recover these costs over the
18 2027 period to support its current credit rating. We have
19 noted that this would require an approximate rate increase

1 of about seven to eight percent for an average across all
2 customer classes.

3 Securitization of unexpected fuel
4 balances has been employed in other jurisdictions and in
5 Nova Scotia previously. So that was with the
6 securitization of the \$500 million fuel balance over the
7 FLG proceeding that Blake had referred to earlier. And
8 these have had successful outcomes to support the credit
9 of those utilities.

10 So securitization allows these fuel
11 costs to be recovered in a cost-effective manner shared by
12 current and future customers who will benefit from the
13 transition, and also would have the benefit or the impact
14 of providing great relief at a time when customers are
15 feeling the effects of higher commodity prices on many
16 goods and service and will provide support to Nova Scotia
17 Power's credit ratings to the benefit of both current and
18 future customers.

19 The inclusion of unrecovered fuel

1 costs, that is included as one of the securitized costs
2 within the securitization regulations, and we believe this
3 has provided us with the tools to increase customer value
4 of the securitization transaction and rate relief for
5 customers bearing the brunt of the energy transition
6 costs.

7 And so for these reasons we believe
8 the inclusion of the fuel costs in securitization
9 transaction is the best approach to provide value for
10 customers.

11 **MR. WILLIAMS:** Yeah. There's more I
12 would add to that, so I'll do so.

13 But I know -- Libby, I saw your hand
14 go up first. I think there's at least one more up. So
15 maybe just take those questions and then I can follow up
16 as needed.

17 **MS. McNAMARA:** Sure. I was wondering
18 about the \$1 billion round number and in terms of market
19 interest, was there any discussion of other round numbers,

1 say, 900 million? Is there any practical sort of
2 considerations with going with a different number if the
3 Board were to, you know, decide to allow for
4 securitization of some costs but not others?

5 **MR. HEISLER:** Yeah, Libby, it's
6 Justin. I'll jump in.

7 So yeah, I think another round number
8 would still be doable if that's what the decision is
9 ultimately. But a part of the thinking in maximizing the
10 \$1 billion, which really is where our financial advisor
11 said we'd probably cap out in terms of interest, the
12 thinking was maximizing that would be the best way to
13 generate the most customer benefit.

14 But to your question, if it was a
15 lower round number, that should be doable as well.

16 **MR. MacDUFF:** Yes, thanks. I had a
17 similar question.

18 And I was just wondering in terms of,
19 you know, the IR process and that analysis, is that

1 something that's kind of quantified to be provided or is
2 it more discussions that were had in terms of achieving
3 the best results?

4 **MR. HEISLER:** Those are basically just
5 discussions, James, that we had with the advisors. I'm
6 not aware of anything -- any type of real analysis. It's
7 just based on their experience.

8 **MR. FLEMMING:** It's difficult to
9 quantify.

10 **MR. MacDUFF:** Yeah, that's what I
11 would assume.

12 The other question that I had, I
13 thought I heard you say that, absent the securitization,
14 NSP would have to recover this amount immediately
15 resulting in a seven to eight percent increase, but then I
16 thought I understood from the application that the NPV was
17 based on an assumption that they'd be recovered over 13
18 years.

19 So is there a bit more explanation of

1 that discrepancy or you can tell me where I've made the
2 mistake?

3 **MR. FLEMMING:** Yeah, absolutely,
4 James. I am going to actually walk through the
5 assumptions of the NPV a little bit later on the NPV
6 analysis. But what I will say is that 13 years
7 encompasses all of those four components, and so the 13
8 years would apply to the thermal assets. We have shown
9 and would expect the recovery of fuel costs on a more
10 expedited basis. But I will touch on that a little bit in
11 more detail later on.

12 **MR. MacDUFF:** Okay. Thanks.

13 **MS. WHITTEN:** Yes. Thank you.

14 I have two questions as well.

15 The first one is the cost allocation
16 for this, am I correct to assume it will be the existing
17 approved cost allocation process or will it be a separate
18 negotiation or agreement among the parties to what cost
19 allocation process to use?

1 And my second question is the
2 assumption of a 60-day turnaround time that I believe
3 you're expecting from the Board, does that leave enough
4 time to go to market and get yield that you say -- I'm
5 sorry, is somebody interrupting or -- can you hear me?

6 MR. WILLIAMS: Yeah, we can hear you
7 just fine, Melissa.

8 MS. WHITTEN: Okay. The yield on long
9 term bonds is kind of volatile to increasing right now.
10 so does that leave you enough time to go to market to find
11 that you can get a yield that's acceptable to the Board?

12 MR. WILLIAMS: Thank you.

13 Mike, do you want to handle the first
14 question and I'll handle the second?

15 MR. WILLETT: Yeah, I can handle the
16 first. Thanks for the question, Melissa.

17 So the FAM balance as of September
18 30th, 2026 would be consistent with the approved
19 methodology in the plan of administration for cost

1 allocation throughout for each customer class. So that
2 balance would be done consistent with if this was being
3 done as a normal AA/BA balance.

4 I am going to get into each of the
5 components later on in the presentation as well, but the
6 balance as of September 30th is consistent with AA/BA
7 process.

8 **MS. WHITTEN:** So you're talking about
9 allocation of all the costs, not just the FAM balance?

10 **MR. WILLETT:** I will be discussing
11 each of the components later on, the allocation treatment
12 to each of the customer classes later on, each of the four
13 components.

14 **MS. WHITTEN:** Okay. And do you have
15 any thoughts on the second question I had?

16 **MR. WILLIAMS:** Yeah, so I can address
17 that, Melissa.

18 So I just want to make sure everyone
19 online is clear. The 60 days is not an expectation of

1 Nova Scotia Power. The 60 days is a legal requirement
2 that's set out in the Regulations. So I just want to be
3 clear on that point, I suppose.

4 And then your question about going to
5 market, we don't have to go to market until after we have
6 an approval from the Board, and we would go to market
7 consistent with whatever that approval is.

8 But to your point, I think, which was,
9 you know, the bond markets are volatile at this time, and
10 I think that's one of the reasons that time is of the
11 essence here is to get a decision quickly. And once we
12 have a decision, assuming it's a favourable decision, we
13 would be moving essentially immediately to market because
14 we are certainly aware of the volatility in those bond
15 markets and we would be looking to lock in the lowest
16 yield possible. And we're aware of the fact that, to the
17 extent that time drags on, yields could go up.

18 And so we will not be wasting any
19 time, assuming there is a favourable decision, and we

1 would intend to go to market, as I said, immediately
2 following a decision in order to retain as much value for
3 customers as possible.

4 MS. WHITTEN: Thank you.

5 MR. ROSCOE: Hi, everyone. Just a
6 couple questions on the fuel side of things from renewals
7 perspective.

8 The amount you mentioned earlier, and
9 I think there's a table in the filing of a rough seven to
10 eight percent rate increase in '27, that reflects all of
11 these costs.

12 Is there information that would
13 highlight what the changes in rate -- in the GRA rates for
14 2027 would be if just the fuel amount here, I guess -- and
15 I assume that's the forty-one seven, you know, the
16 forecasted fuel shortage for the next kind of -- well, I
17 guess it's a bit longer than a year.

18 Is there a description of what that
19 piece on itself would look like? And I guess a second

1 part to that question is, would that not yield lower
2 overall costs because that -- they've just paid it in the
3 year it was incurred? It wouldn't have any interest or
4 any kind of long-term amortization.

5 Wouldn't that be a lower overall cost
6 for customers?

7 **MR. WILLIAMS:** Before you jump in on
8 that, but just to be clear on that 78 percent, I think,
9 Dan, that is not the entirety of the outstanding. It's
10 just the FAM balance up to the end of September, so it'd
11 be 78 percent just to recover that 149 or that roughly
12 \$150 million.

13 **MR. ROSCOE:** Okay. That's 149, not
14 the 214. Okay.

15 **MR. WILLIAMS:** That's right.

16 So I -- that helps put all this into
17 context and then -- we're talking about big numbers here.
18 If these components are not included in securitization, it
19 would mean that we're coming in for a rate ask, as I said,

1 seven to eight percent essentially immediately because
2 we're already late on this AA/BA filing because we've been
3 trying to work through this securitization process, but if
4 we -- for some reason, this fuel was not included in
5 securitization, that will require a significant -- a
6 significant rate increase immediately.

7 And I think that goes to one of the
8 points I wanted to raise -- and sorry to kind of -- I'll
9 take the response to you again, but before I lose the
10 thought, I want to go back to Craig's discussion with
11 Libby about, you know, some of the benefits of doing this
12 and why including the fuel.

13 And I think it's important to
14 recognize -- and by no means am I speaking for government
15 and I recognize that government has left this to the
16 Board's decision, but by including these unrecovered fuel
17 (indiscernible - poor audio) as defined in the Regulations
18 to include a pre-payment on fuel costs and fuel costs in
19 general, it is a policy decision by government. Again, I

1 fully appreciate and acknowledge that they're leaving that
2 ultimately to the Board. But by just including it in
3 there, it's recognizing the importance of these fuel costs
4 and it's recognizing the importance of these fuel costs
5 and what they would mean in terms of a potential rate
6 increase for customers.

7 And that needs to be recognized in the
8 current policy context of what we see from the provincial
9 government lately, but probably more immediately from the
10 federal government last week with their announcement of a
11 \$2 billion investment in electric heating, fuel
12 conversions and retrofitting apartments, so there is, I
13 think, a discussion to be had about the importance of
14 avoiding significant rate increases in the near term as
15 we're intending to transition this province into the
16 renewable phase, electrification phase.

17 And having those types of significant
18 rate increases would fly in the face, really, of those
19 policy objectives and discourage the adoption of things

1 like heat pumps where there's very specific and
2 concentrated policy directives from both levels of
3 government aimed at those conversions.

4 So I do think that's a significant
5 part of the discussion as well where we're avoiding --
6 avoiding those types of rate increases and those,
7 obviously -- those policy directives, then, obviously have
8 a future benefit for customers because you're growing that
9 load base, you're then spreading fixed costs over a larger
10 number of customers, a larger number of kilowatt hours,
11 and that has significant benefit for those future
12 customers.

13 You're doing that in relation to both
14 the existing fixed costs, but also the securitization
15 rider will become a new fixed cost and for every kilowatt
16 hour you're adding to the system, that -- each customer
17 share of the securitization rider, the securitization
18 surcharge on a go-forward basis is diminished.

19 So there is a significant benefit for

1 customers to grow that load and having a significant rate
2 increase really jeopardizes that policy objective, I
3 think.

4 So sorry. That was a bit of a
5 sidetrack, but Craig.

6 **MR. FLEMMING:** Yeah, so thank you.

7 So Daniel, I was going to start by --
8 I was going to start my response the same way Blake did,
9 just to reiterate that the -- both the seven to eight
10 percent approximate rate increase would be -- adjust for
11 that balance there, the almost \$150 million, to September
12 30th, which actual figures that we now have is just a
13 little bit over \$150 million, almost \$151 million.

14 The -- in terms of the forecast future
15 under-recovery, so using the same type of logic that we
16 had there about seven and a half percent there for the
17 balance to -- balance of 150 million there, we expect that
18 to be in the area of about two -- a little bit over two
19 percent increase associated with that \$40 million.

1 We have in terms of -- again, going
2 back to the NPV analysis, we have done a profiling of when
3 we would expect under a without securitization scenario to
4 recover those amounts, but we would expect that that would
5 be an increase of about just a little over two percent.

6 And to your point about that would be
7 less because you're recovering in the year, you're
8 absolutely right. We have not included any interest
9 component on this amount. This is purely just comparing
10 the expected FAM fuel costs to expected FAM fuel revenue,
11 so there is no -- there's no interest component associated
12 with this forecast under-recovery.

13 Nova Scotia Power, upon issuance of
14 the securitization bonds, though, would put the amount
15 into the FAM. To the extent that that would put us in an
16 over-recovery position, Nova Scotia Power would, of
17 course, credit interest to the benefit of customers on the
18 FAM.

19 MR. ROSCOE: That's helpful, Craig.

1 **MR. MacDOUGALL:** With respect to the
2 over or under-recovery and the additional FAM prepayments,
3 do they then -- they don't go into the FAM in the future.
4 They're already accounted for, so it's -- it's not
5 considered another cost to the FAM balance.

6 **MR. FLEMMING:** So we would put that --
7 once we have received the funds, we would allocate those
8 costs to the appropriate assets from the application. We
9 would true-up the FAM. We think there's going to be a
10 slight difference because we're using forecast amounts for
11 the PHP and IESO variance, so to the extent that those
12 were a little bit different, that may increase -- slightly
13 increase or decrease the amount applied to the FAM.

14 But that money goes into the FAM, so
15 that money -- once we have it, that lowers Nova Scotia
16 Power's rate base and Nova Scotia Power no longer earns an
17 equity return on that and Nova Scotia Power would put the
18 funds into FAM and the customers would receive the benefit
19 on the interest earned on the over-recovery balance.

1 **MR. MacDOUGALL:** So there are dollars
2 as a credit into the FAM account.

3 **MR. FLEMMING:** That's correct, David.

4 **MR. MacDOUGALL:** Thank you.

5 **MR. ROSCOE:** I'm just looking to --
6 yeah, I wanted to -- I wanted to respond to the questions
7 -- or to the answers to the original question I had, first
8 and foremost, to mostly Blake's comments.

9 We're -- renewal and generally the
10 renewables retail market is generally supportive of
11 including the past FAM amounts in this process. The
12 customers that switch to the renewables retail market will
13 be still liable for, you know, costs -- previous costs
14 incurred, so having that amortized over a long period at a
15 good interest rate is of benefit to those customers
16 switching.

17 Where we bristle at the suggestion
18 that now precedent has been set about financing fuel costs
19 and we also have issue with future fuel costs being done

1 in this way when they could be addressed with a very
2 reasonable rate adjustment that would be way lower than
3 all other types of fossil fuels like heating oil and
4 gasoline and diesel that have all gone up, you know, 50 or
5 60 percent over the last year -- and coal costs as well --
6 you know, that would be small, but then it's the interest
7 on the securitization that you're adding to that fuel
8 amount. That 41 percent -- or 41 million is going to earn
9 the bond rate over the whole period of the bond, so that's
10 a ton of interest that's going to be added to ratepayers
11 that would be avoided if they just paid the real cost --
12 the actual cost of fuel in the year it is incurred.

13 And I think it's a real big step to
14 include future fuel costs in this process under the guise
15 of making it, you know, more efficient by rounding up to
16 \$1 billion.

17 **MR. WILLIAMS:** Yeah. Well, it's not
18 under a guise at all, Dan, so I -- just to be clear.

19 It's recognizing that we are going to

1 be in an under-recovery position next year, and part of
2 that is because of the smoothing that was done in the GRA
3 where we took fuel costs into 2026 to smooth the rate
4 increase, and so we're going to be -- we're expecting to
5 be in an over-recovery position in '26 and an under-
6 recovery position in '27. With the way fuel markets have
7 gone and where we are already in '26, it's very clear that
8 we're going to be under-recovered in '27 with a BCF not
9 intending to be done until 2028.

10 So it's not under a guise and I think
11 it's a very reasonable approach to be -- to be doing this.

12 I think it's a fair question, though,
13 to say, you know, if we do this now, what's to say we're
14 not going to be in this position in 2028 and 2029. That,
15 I think, is a fair question to be asked.

16 And you know, I've had some
17 discussions with people on this phone call to alert them
18 to our intent, is to decouple fuel from our general rates,
19 is to have fuel handled separately and, as part of that,

1 to have a more nimble FAM process where we are truing up,
2 not on an annual basis, but we're truing up whether it's
3 on a monthly, bi-monthly or quarterly basis. The point of
4 that being is that we're not generating these types of
5 balances. We're having a FAM that's more responsive to
6 fuel costs and we're not generating these balances, we're
7 not, to your point, incurring financing costs that are
8 then adding to the fuel costs themselves.

9 So that, I think, is the ultimate
10 solution, but to be able to get there, we need to really
11 clean -- you know, clear the slate and start afresh with a
12 FAM that can be more responsive or more nimble to these --
13 I mean, it's just a simple fact that fuel markets are
14 volatile. And with what we're seeing in the geopolitical
15 realm today, tomorrow, in the future, like we're not going
16 to get any more stable in terms of these fuel markets so
17 we need to be more nimble in how we're responding to them.
18 Otherwise, we're going to be having these -- continuously
19 having these types of balances that we need to deal with,

1 and we're certainly recognizing that it's not in
2 customers' best interests to have those types of balances,
3 and not in anyone's best interest.

4 And so I think ultimately that's the
5 solution, and this is part of the path to get there.

6 **MR. ROSCOE:** Okay.

7 **MR. FLEMMING:** I believe, Libby,
8 you're the next one I saw the hand.

9 **MS. McNAMARA:** Yeah. In terms of the
10 prepayment, that FAM prepayment amount in the Application,
11 it's worded that the pre-payment amount would be a
12 securitization regulatory asset, which to me -- what you
13 were saying a minute ago sounded correct, that it would
14 reduce the FAM balance, which is a regulatory asset, but I
15 -- so I was just a little bit worried or confused about
16 the wording in the Application.

17 **MR. FLEMMING:** Sure. Absolutely.

18 So the way that it works, Libby, would
19 be debit securitization asset, credit the FAM, and then

1 that securitization asset is -- that's what is used for
2 the -- I'm drawing a blank here in terms of -- just not a
3 loan, but the ---

4 **MR. FERGUSON:** Yeah, might be what's
5 effectively transferred to the limited partnership.

6 **MR. FLEMMING:** The limited
7 partnership. Thank you, Eric. Yeah, exactly right.

8 So Libby, basically what happens is
9 that all the funds that are received, that 987.5 in this -
10 - in the proposed scenario, that would all go into
11 reducing those -- you know, whether it be property, plant,
12 equipment or regulated asset. So that -- if everything
13 worked out the way that we had projected, that 214.5, if
14 we get to the end of the year and we are at a FAM balance
15 of, let's say, 180 million, we would then move that into a
16 FAM liability or a credit to customers, an amount owing to
17 customers of \$34.5 million.

18 **MS. McNAMARA:** Okay. And I have some
19 more questions on the whole accounting, but I'm assuming

1 you're going to touch on that a little bit later. Should
2 I wait for whenever you reach that part?

3 **MR. FLEMMING:** I think -- go ahead.

4 **MR. FERGUSON:** I was thinking do it
5 now.

6 **MR. FLEMMING:** Yeah. Yeah, go ahead.

7 **MS. McNAMARA:** Okay. So are the
8 actual assets being transferred to the LP?

9 Like are the -- is the -- the coal
10 thermal assets, are they coming off the balance sheet of
11 Nova Scotia Power?

12 **MR. FERGUSON:** No, the physical assets
13 will stay with Nova Scotia Power. It's a regulatory asset
14 representing the net book value of the assets, but the
15 physical assets stay with NSP.

16 **MS. McNAMARA:** Okay. Does that -- so
17 I also have questions about how -- where income tax
18 arises. Because in my mind, I was thinking the LP would
19 have expenses, being depreciation of the retired assets

1 and interest on the bonds, and it would collect revenue
2 exactly equal to its expenses. And I'm not understanding
3 where -- why there would be income tax for that entity.

4 **MR. FERGUSON:** Yeah, so you're there
5 on the interest component. It'll be the interest revenue
6 that matches the interest expense in the LP. Because the
7 physical assets stay in Nova Scotia Power, the tax
8 deductions, the capital cost allowance that's left on
9 those assets stays in Nova Scotia Power, but the
10 collection of the -- the return of capital, the
11 amortization of that reg asset, gets collected in the LP.
12 So the LP's got back income no offsetting deduction, if
13 that makes sense.

14 **MS. McNAMARA:** So would the tax
15 expense in the LP be offset by a deduction in Nova Scotia
16 Power?

17 **MR. FERGUSON:** That's right. Like not
18 perfectly offset because tax deductions are a bit

19 accelerated relative to accounting, but it very much is a
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1 geography question, essentially. From a tax deduction
2 perspective and from a taxable income on the return of
3 assets perspective, where the deductions and income are
4 happening are different here than would otherwise be the
5 case, but the actual amounts of the income and deductions
6 are the same as if it would have kept going to Nova Scotia
7 Power. The difference here, really, is removing the
8 equity component of the financing on these assets so that
9 there's no income to be taxed.

10 **MR. FLEMMING:** So that's how we reduce
11 the overall tax expenses, eliminating the equity return,
12 but the bulk depreciation amount is the same.

13 **MS. McNAMARA:** Okay. So if all of the
14 -- if the assets and then also the related debt are still
15 going to be on the balance sheet of Nova Scotia Power, how
16 does that improve the credit metrics?

17 **MR. FERGUSON:** So the related debt
18 won't be on the books of Nova Scotia Power. So when the
19 regulatory asset gets transferred down and refinanced with

1 bonds, you've got sort of the full billion -- let's bill -
2 - the full billion down there. So that regulatory asset
3 is completely debt financed.

4 Nova Scotia Power will get the
5 proceeds, the billion dollar proceeds, and it will reduce
6 debt and equity in accordance with its capital structure.
7 So there will be less debt in Nova Scotia Power itself.

8 From an accounting perspective, Nova
9 Scotia Power will consolidate the limited partnership, but
10 the credit rating agencies will exclude the billion
11 dollars of securitization debt when they calculate Nova
12 Scotia Power's metrics.

13 **MS. McNAMARA:** Okay.

14 **MR. WILLIAMS:** Anything else, Libby?

15 **MS. McNAMARA:** Okay.

16 **MR. WILLIAMS:** Okay.

17 **MR. FERGUSON:** So this next slide is
18 just an overview of the financing costs, the 12 and a half
19 billion up front financing costs that Craig mentioned

1 earlier, A lot of these costs would be very similar to
2 what we would have seen in the FLG-2 proceeding, and so I
3 won't touch on those in detail.

4 One that I did want to touch on that's
5 a bit different is the capital reserve account item. So
6 really what this is, and it's referred to in the
7 Application as being required for credit enhancement, so
8 this is really a credit rating agency requirement.
9 Because this is a volumetric charge and we need to make
10 sure that we have money to pay bondholders, we're required
11 to keep a little bit of cash. So we'll take five million
12 of the proceeds and hold that in the limited partnership
13 to make sure that we've got enough money to pay
14 bondholders to the extent that, say, load is lower than we
15 expect and we don't get as much revenue as we thought we
16 would have. We can't wait until the true-up process
17 unfolds to pay a bondholder. So we keep that little bit
18 of cash in the LP to make sure we can pay bondholders in a
19 timely fashion. And again, that's a rating agency

1 requirement to keep that cash there.

2 Maybe turning to the next slide, so we
3 have up front financing costs. We also do have some
4 ongoing financing costs.

5 Again, some of these would be similar
6 to what we've seen in other proceedings. So the allotted
7 fees, this limited partnership will require a standalone
8 audit, ongoing rating agency fees, and some administrative
9 costs relating to things like trustee fees.

10 The other item here is servicing fees.
11 And so this is really the charge from Nova Scotia Power to
12 the limited partnership to compensate Nova Scotia Power
13 for the incremental costs it's incurring for
14 administration so things like accounting, tax returns, the
15 regulatory filings related to the limited partnership
16 because the limited partnership itself will not have any
17 employees to do those things. And so that \$500,000 figure
18 is based on -- it's .05 percent of the billion-dollar bond
19 issuance. And that fee and that magnitude of fee is

1 consistent with precedent transactions that we've seen in
2 the U.S. from a securitization perspective.

3 The only other item I wanted to flag
4 on this slide is income tax. So as you see, you have year
5 one costs here, but we also have the total ongoing
6 financing costs that factor into the net present value
7 calculation. So the servicing fees are at 500,000 a year
8 in duration of the bonds.

9 We have escalated the other fees you
10 see here at two and a half percent to account for
11 inflation. And that's what's baked into the net present
12 value math.

13 From a tax perspective, that 310
14 million represents the tax associated with the return of
15 capital that I mentioned earlier. Customers would see
16 about \$110 million in savings because there is no return
17 on the equity component, so there's no income to pay tax
18 on in the securitization structure.

19 The last thing I wanted to highlight

1 here. We don't have any income tax in year one costs, and
2 so that's because although the limited partnership would
3 itself have taxable income, we're proposing to look at
4 this from an overall Nova Scotia Power perspective.

5 So said another way, even if the
6 limited partnership is taxable, if we have tax attributes
7 at Nova Scotia Power that could shelter that taxable
8 income, we're proposing to not include any tax in the
9 rider. So really, we don't want to be collecting any tax
10 in advance of when we really need to pay it on a combined
11 Nova Scotia Power plus limited partnership basis.

12 Back to you, Craig, if there's no
13 questions.

14 **MR. MacDOUGALL:** Is that the reason
15 for the use of an LP structure?

16 **MR. FERGUSON:** No. The LP structure
17 is really more driven from a legal perspective and then
18 creating the most efficient bankruptcy remote vehicle and
19 the tax -- the tax elements of this, really, just are the

1 fallout from the selection of a limited partnership.

2 In some U.S. transactions it will
3 sometimes be done using a trust, but the guidance from our
4 legal counsel was that the limited partnership was the
5 best vehicle.

6 **MR. FLEMMING:** So I will speak to the
7 present value analysis.

8 And so in order to quantify an
9 expected savings to customers as a result of this
10 transaction, we compared total customer payments under a
11 set of with and without securitization scenario.

12 We have assumed an interest rate for
13 the securitization bond based upon the guidance received
14 from our financial advisors for the transaction. The bond
15 is a 30-year mortgage style bond, so very similar to how a
16 mortgage would work. You pay more interest in the early
17 years and a lower amount of principal and as your
18 principal decreases, so does your interest expense in any
19 given year and the amount that goes towards the principal

1 in paying down the bond increases.

2 We have also included in our Appendix
3 B a table that shows the reduction in the net present
4 value of revenue requirement of the transaction under
5 different interest rates. So we have -- again, we've put
6 in the interest rate that our financial advisors have said
7 to us is indicative of what they thought at the time of
8 the application that they could get, but we've also shown
9 some sensitivity analysis to show, okay, if it were to
10 increase by 25 basis points, decrease by 25 basis points,
11 50 basis points, and have included a break-even interest
12 rate in the analysis as well. Again, that's in Appendix B
13 of our Application.

14 And so in order to carry out the
15 analysis, we had to make some assumptions around the
16 timing of recovery for the costs in the scenario where
17 securitization does not move forward. And so they are
18 different for different -- for the different components.
19 So I'll run through those briefly.

1 The first would be the thermal assets.
2 So Nova Scotia Power has, as of May and the approval of
3 the General Rate Application, deferred depreciation
4 expense and financing costs associated with those assets.
5 That is only up until the period of December of 2027.

6 So we have assumed in a case where
7 scenario -- a scenario where securitization does not
8 proceed that we would resume depreciation expense on those
9 assets at the previously approved rate. And so that would
10 be \$26.8 million annually. It would be a depreciation
11 expense that would be included in rates. As well, there
12 would be financing costs associated with the net book
13 value or rate base associated with those assets.

14 And then we have assumed that at the
15 end of 2029 through a 10-year period, 2030 through 2039,
16 provided those were retired at the end of the decade, we
17 would amortize the remaining amount of that balance over a
18 10-year period, so basically recover all the net book
19 value by 2039.

1 And then with the deferred financing
2 costs associated with that, we've assumed that we are
3 amortizing that over a 12-year period, so a straight line
4 over a 12-year period consistent with the thermal assets
5 that begins in 2028 and we would fully recover by the end
6 of 2039.

7 The fuel and purchase power, so this
8 is consistent with how we expect the future under-
9 recoveries to unfold. So we would have expected \$149.6
10 million. That would be the under-recovered costs at the
11 end of September of 2026. That would be normally what
12 would be included in an adjustment or an AA/BA application
13 to be recovered over the following year. So we are
14 showing that being recovered in 2027.

15 The forecast under-recovery, so
16 October 2026 to September 30th of 2027, that is an under-
17 recovery of \$32.5 dollars forecast since we'd recover that
18 in 2028. And then the remaining amount that's from the 4th
19 quarter of 2027 and the future under-recovery, that is

1 2029.

2 So profiling that according to when we
3 would expect to under-recover and according to the normal
4 process for an AA/BA application and recovery.

5 The PHP recovery, we assume that that
6 will be in 2028 through adjusted general rates and then
7 the IESO deferral assumed recovery in 2027, beginning in
8 2027 through an IESO rider.

9 And so looking at all of that and so
10 comparing the 30-year securitization mortgage style bond
11 at the assumed interest rate to a scenario where we
12 recover the assets upon this schedule, that's our
13 assumption, we have calculated a net present value
14 decrease in customer payments or an increase in customer
15 benefits of \$265.6 million, so very significant. A 21
16 percent savings between a with and without securitization
17 scenario.

18 I'll pause there. James, I see you
19 have a question.

1 **MR. MacDUFF:** Yeah, no. And so it's
2 helpful that that reference there that in the recovery
3 period of 13 years only applies to the thermal assets and
4 then this analysis and these numbers assume how you set
5 out in the remaining bullets?

6 **MR. FLEMMING:** That's exactly right.
7 So fuel and purchase power 2027 through 2029, the amount
8 that we are proposing recover through the transaction
9 without securitization, that's how we would expect to
10 recover it. And then PHP, all in 2028, and then IESO
11 referral all in 2027, but with the thermal assets
12 recovered over that 13-year period.

13 And again, it's just due to the
14 significant amount of it and going back to the normal
15 process that we would have absent securitization.

16 **MR. MacDUFF:** Excellent. So if any
17 -- if nothing else, you've saved a few IRs from me by
18 giving this slide, so that's good.

19 I haven't looked at the NPV, you know,

1 sensitivity analysis or anything. I'm just curious if --
2 was there any other securitization periods lower than 30
3 years checked or calculated or is that something that
4 could be done?

5 **MR. FLEMMING:** There was certainly not
6 one included in the application. I'm not sure if we would
7 be able to issue that tenor of bond for -- that amount of
8 bond for that tenor. We'd have to maybe follow up on
9 that.

10 **MR. WILLETT:** Yeah, I think that's
11 right, yeah.

12 **MR. FLEMMING:** We'd have to take a
13 look at that, James, so is that certainly an IR that ---

14 **MR. MacDUFF:** Yeah, just because I
15 think, if I'm not mistaken, the Regulations say, you know,
16 up to 30 years, but it doesn't prescribe 30 years and it
17 was just one of the questions that myself and other
18 parties might have is, you know, was there consideration
19 of a slightly shorter year, what would be the impact of

1 that. So there might be some questions on that, but I'll
2 think about it.

3 MR. FLEMMING: We can certainly look
4 into that, James.

5 MR. MacDUFF: Right.

6 MR. FLEMMING: Daniel?

7 MR. ROSCOE: Just a quick one from me.
8 What -- the net present value involves a discount rate.
9 What discount rate are you using and is it the same for
10 both scenarios?

11 MR. FLEMMING: The same for both
12 scenarios and it is Nova Scotia Power's approved weighted
13 average cost of capital in 2026, and that is 6.59 percent.

14 MR. ROSCOE: Okay. Thank you.

15 MR. FLEMMING: And just an additional
16 illustrative slide just to hopefully be helpful here.

17 Just a little bit further analysis
18 just to break down the net present value by component to
19 show the amount that is being derived from each of these.

1 And so the thermal assets, being by
2 far the largest balance, provides the most benefit from an
3 NPV and revenue requirements perspective and, as you can
4 see there, every one of these components, including them,
5 provides a reduced revenue requirement to customers on a
6 net present value basis with the inclusion of the FAM cost
7 providing over \$20 million along with that, of course,
8 near term for customers.

9 That's it for me.

10 **MR. FERGUSON:** Okay. So we did touch
11 on this a bit in response to one of these questions, but
12 just to put it all together in terms of what the structure
13 looks like and what the cash flow looks like.

14 So Nova Scotia Power will form a
15 limited partnership. It will transfer those regulatory
16 assets into the limited partnership. The limited
17 partnership will go out and issue the bonds and then the
18 limited partnership will loan the proceeds from those
19 bonds up to Nova Scotia Power.

1 I just want to pause on this one for a
2 moment because one of the things that we would have
3 highlighted as a consideration in previous proceedings
4 when we first started talking about securitization was
5 coming up with a structure to do this on a tax deferred
6 basis so we don't trigger a big gain out of the gate. And
7 so the reason that this is a loan of the proceeds up to
8 Nova Scotia Power as opposed to a dividend is to manage
9 that tax result and ensure we don't have an adverse tax
10 consequence for customers as a result of the structure.

11 So if anybody was curious about why
12 it's a loan, that's why it's a loan.

13 On the righthand side of this page on
14 an ongoing basis, the way this would play out is Nova
15 Scotia Power will collect the securitization rider on
16 behalf of the LP and remit those funds to the LP. The LP
17 would then use that money to pay bondholders.

18 The other pieces of the cashflow here
19 relate to the intercompany loan, and so Nova Scotia Power

1 would pay interest to the limited partnership on that
2 intercompany loan and then the limited partnership would
3 take that interest and distribute it back up to Nova
4 Scotia Power as a distribution. As it's described in the
5 application, that really is a separate transaction to
6 manage the tax result as opposed to a base part of the
7 securitization.

8 **MR. WILLIAMS:** Okay. If there's no
9 questions on that, I think, Mike, over to you.

10 **MR. WILLETT:** Thank you.

11 So I'm just going to go through the
12 cost-of-service treatment for the various components of
13 the securitized costs. This is outlined in Section 6 of
14 the application.

15 So first of all, before getting into
16 each of the four components, there's an up-front
17 allocation of the financing costs and ongoing costs to
18 each of the buckets based on their share of the
19 securitized costs.

1 So we saw in previous slides the 12.5
2 million. That would be allocated to each of those four
3 buckets based on the percentage shares of the securitized
4 costs.

5 For the thermal assets and the
6 deferred financing costs of those thermal assets, the
7 revenue requirement for that component is treated similar
8 to the approved methodology for generation assets that is
9 currently in place in the cost-of-service. So that is
10 using the 2027 total system coincident load factor.

11 Costs are functionalized between --
12 not functionalized -- classified between demand and
13 energy. And then in order to allocate those costs to the
14 various customer classes for the demand component we are
15 using the 3 CP, three coincident peak, methodology in
16 order to allocate those costs to various customer classes.
17 And for the energy component of the thermal assets, that
18 is based on the 2027 share of energy by each of the
19 customer classes.

1 James, do you have a question there?

2 **MR. MacDUFF:** Yeah, Mike. Just when
3 you say here 2027, is it -- there's going to be a number
4 for each year, right. So in 2028, is it going to be done
5 based on the 2028 forecast share?

6 **MR. WILLETT:** So that -- so obviously,
7 you know, there's going to be future applications each
8 year for this. We would be updating the load forecasts
9 and it would be my expectation that on the thermal asset
10 side that it would be exactly as you referenced, each year
11 you would be looking at the SLF and doing that math for
12 the revenue requirement for that upcoming year.

13 **MR. MacDUFF:** Right. So you're not
14 fixing each class's allocation for all 30 years out in
15 this treatment, just it's going to be done on a cost-of-
16 service basis annually, some rider of some form?

17 **MR. WILLETT:** And I would say that on
18 the thermal assets that is the case, but for items like
19 fuel and purchase power we would be doing -- those costs

1 have been incurred on 150 million so we would know exactly
2 what classes are responsible for those costs and
3 essentially be locking in the cost responsibility for each
4 of those classes.

5 **MR. MacDUFF:** Yeah, no. Understood.
6 Great. Thanks.

7 **MR. WILLETT:** All right. So I'll move
8 on to fuel and purchase power.

9 So within our application, Appendix C
10 outlines the treatment of the \$150 million related to the
11 balance as of September 30th, 2026. So this would be very
12 consistent and familiar to most on the call from normal
13 AA/BA applications. Attachment 1 to that appendix would
14 include the FAM calculation model. Attachment 2 and
15 Attachment 3 would be the calculations of the AA and BA
16 balances by individual customer class.

17 So this has been treated consistent to
18 the normal process for true-ups for the FAM under the
19 AA/BA.

1 For the second component of the FAM
2 balance, which we've referred to as the prepayment of
3 future fuel and purchase power costs, what we have done
4 here is based this off of what the share of 2027 base cost
5 of fuel revenue would be for each customer class. And as
6 Craig mentioned earlier, that would then be applied as a
7 credit to the FAM so those customer classes would have
8 that credit applied to their FAM balance.

9 Next I'll discuss the PHP deferral
10 treatment. So the additional FCR as a result of moving
11 PHP to an above-the-line class versus its former below-
12 the-line tariff resulted in increased revenue in both the
13 generation and transmission functions within Nova Scotia
14 Power's GRA for '26 and '27. That resulted in lower cost
15 responsibility for those functional areas.

16 So the company has, for the PHP
17 deferral, functionalized this cost within the generation
18 and transmission functional areas, and that's based off of
19 the rate base as of December 31st, 2026 for the company in

1 both of those functions, transmission and generation.

2 And then the generation related
3 portion is treated similar to what I discussed in the
4 thermal asset. This is done based on the SLF treatments.
5 And then when we allocate those to customers between the
6 demand and energy components, the 3 CP and the annual
7 energy requirements for 2027 for each class is used to
8 allocate the various costs to customer classes.

9 For the transmission related portion
10 that's 100 percent demand and would utilize the 3 CP
11 methodology.

12 And the last component is the IESO
13 Nova Scotia deferral. So the company has used the same
14 methodology proposed by the IESO in its application to the
15 Board for its allocation of its revenue requirement to
16 load serving entities. So this is allocated based on
17 energy and each customer class's share of energy of 2027
18 forecasted sales.

19 I'll next go onto the rate impacts.

1 So this information that I'm presenting now over the next
2 two slides is the same information as included in the
3 application for Figure 6, Figure 7 and Figure 8.

4 So as you can see, the company has
5 broken down the percentage increase related to each
6 component, the four components of the securitization
7 rider, and in total. And as you can see, for the total
8 FAM classes, there's a 3.3 percent increase in 2027.

9 We can move on to the next slide. And
10 this is just showing -- because the previous slide showed
11 the impact to FAM customers, this is showing the impact on
12 the below-the-line riders and the OATT Munis. The reason
13 we've broken out OATT Munis is this is consistent with the
14 treatment historically of FAM costs. Because we have the
15 four OATT Munis and Lunenburg, and the four OATT Munis
16 have different FAM responsibilities than the one municipal
17 customer, Lunenburg, they have been broken out separately,
18 calculated separately and proposed as being direct payment
19 similar to the treatment of FAM and actually DSM costs for

1 this -- these customers.

2 And I didn't have a slide for it, but
3 the last item I'll discuss is -- oh, there's another
4 question. Rebekah?

5 **MS. POWELL:** Thanks, Mike. I have
6 just a quick question on the last slide because it
7 connects with Attachment -- Appendix H, where ELID is
8 listed as a below-the-line class where it's for an above-
9 the-line ---

10 **MR. WILLETT:** Yeah, I mean --

11 **MS. POWELL:** Can you just walk me
12 through that?

13 **MR. WILLETT:** Yeah, it's just listed
14 as a below-the-line here until they're -- because
15 currently they are not a FAM customer until there's an
16 approved above-the-line tariff. They've just been listed
17 here as a below-the-line until they would be approved as a
18 FAM customer.

19 David?

1 **MR. MacDOUGALL:** This is just going
2 back to the comments earlier on about the process here.
3 Is NSP requesting in this application that the
4 securitization riders like this be approved in -- approved
5 now subject to then a potential change later or are they
6 just asking that your assets be allowed to be securitized
7 and all of what's gone on on these two slides is to be
8 dealt with at another time?

9 It's just this information on cost-of-
10 service stuff is in this application, but is this the
11 application that you want to actually have the Board
12 approve that rider and then just review it later for
13 potential revisions to how the costs are allocated?

14 **MR. WILLIAMS:** Yeah. That's -- it's
15 yes to both your questions, David, that, yeah, it would be
16 our expectation as they're approving the rider effective
17 January 1st, 2027, but that it's approved on an interim
18 basis and subject to true-up once the final determination
19 on the cost-of-service has been made.

1 And that's why you'll see in the
2 Application that the rider itself as well the red lines or
3 black lines for the tariffs.

4 James?

5 **MR. MacDUFF:** Yeah. And just to
6 follow up on that, Blake, like if there was like, you
7 know, a change to the amount of securitization that the
8 Board ended up approving that changed these in a bit of a
9 fundamental way, like is there a possibility the Board
10 might say, "Just recalculate the rider, but we're still
11 doing it on the January 1" or is it even like -- you know,
12 like if they approve something other than the one billion,
13 I'm just thinking, for example, you know, that these
14 numbers are set on that basis.

15 If it was the 900 million, just to
16 take a hypothetical, that would change these numbers by
17 some order of magnitude, but is it still the thought,
18 "Well, we'll just go with these numbers on the interim
19 basis regardless as long as some form of securitization is

1 approved and then everything will be dealt with in a true-
2 up"? Or I guess that's up to the Board to do what it
3 wants in its order.

4 **MR. WILLIAMS:** Yeah, yeah, up to --
5 you're right. Absolutely up to the Board. And I think
6 probably somewhat depends on the order of magnitude of
7 what's different from what's applied for, but it's
8 certainly our intent that to go -- like I said earlier,
9 we'd go into market right away and so it would be our
10 intent that we have the surcharge being collected through
11 the rider as of January 1, 2027.

12 And then, you know, I think part of
13 this discussion, too, James, would be, you know, how
14 material any changes are with a final decision would maybe
15 dictate whether that true-up happens as part of that final
16 decision, needing to true it up at the end of the year as
17 part of the normal course.

18 **MR. MacDUFF:** Yeah, no, that makes
19 sense. Thanks.

1 **MR. WILLIAMS:** Dan?

2 **MR. ROSCOE:** Yeah, thanks. The -- I
3 see there are -- is the intention that the rider would be
4 expressed solely as a rate-per-kilowatt hour per the
5 calculations that predate -- you haven't actually provided
6 it, but in Section 7, it talks about this is essentially
7 going to be a rider-per-kilowatt hour despite some of the
8 allocations being more demand-related allocations.

9 **MR. WILLETT:** Yeah. Currently, yes,
10 that is on a cents-per-kilowatt hour. Yeah.

11 **MR. ROSCOE:** Okay. Thank you.

12 **MR. WILLETT:** Okay. The last item, I
13 don't have a slide for it, but just it's related to the
14 true-up and it's described in the Application.

15 The company is proposing to use nine
16 months of actuals and three months of forecast and file an
17 application each year by November 1st in order to do the
18 true-up calculation that would be approved in each year.
19 Figure 9 in the Application provides a visual

1 representation of the true-up.

2 For those of you familiar with the FAM
3 process, very similar to the FAM process regarding the
4 components of the true-up, there's -- instead of calling
5 it AA and BA, though, we have it called BA-1 and BA-2.
6 And those would be the two components to true-up any
7 over/under collections related to the securitization
8 surcharge.

9 Libby?

10 **MS. McNAMARA:** On that November 1st
11 filing, I just wanted to clarify, what exactly is going to
12 come in that November 1st filing? Will it be the
13 securitization surcharge -- the anticipated securitization
14 surcharge, which then feeds into a tariff and the previous
15 year's true-up?

16 **MR. WILLETT:** Yeah, that would be my
17 expectation. Yeah.

18 **MS. McNAMARA:** Okay. And it's not --
19 I believe you said you haven't decided yet when that --

1 and sort of after the filing or issuing of the bonds, the
2 true-up, would that be part of next year's November 1st
3 filing or that may be done sooner?

4 **MR. WILLIAMS:** Yeah, I think all I was
5 getting at, Libby, is if there's -- if as a result of the
6 final -- so assuming that the rider is put in place on an
7 interim basis January 1, 2027 in more detailed or fulsome,
8 lengthier, whatever you want to call it, regulatory
9 process plays out over the subsequent months, and the
10 decision from the Board is then issued, let's say in
11 March, just throwing a date out there. If it's a material
12 change in what the rider would collect from each customer
13 class, then ultimately -- and ultimately it is up to the
14 Board, but I think it would make sense to do the true-up
15 as part of the compliance filing on that final decision so
16 that we're not finishing out the year with rates that we
17 know are materially different than what they need to be.
18 It it's just some tinkering and really nothing of a
19 material nature, then maybe it makes sense to just play

1 out the year and true-up it at the end of the year.

2 Ultimately, that's up to the Board.

3 **Ms. McNAMARA:** Okay. Thanks.

4 **MR. WILLIAMS:** Any questions from
5 anyone else on what Mike had spoken to or anything we've
6 spoken to today or, quite frankly, anything else that
7 relates to the Application?

8 Okay. I hope this was helpful for
9 everyone. It was our intention. I think from the sounds
10 of, you know, the questions and discussion we had, it
11 likely was helpful, but as I said kind of when we opened
12 up, this is -- by no means needs to be the end of these
13 types of discussions.

14 If you do have questions that would
15 help in your understanding at any point throughout this
16 process, then we are available and always happy to have a
17 discussion. Simply do not hesitate in the slightest to
18 reach out to either myself or Mike, and then we can then
19 try to address as needed.

1 But if that's it, then I'll just
 2 conclude by thanking everyone for their time today and
 3 look forward to continuing this discussion with you all
 4 over the coming months.

5 Thanks, everyone.

6 --- Upon concluding at 12:47 p.m.

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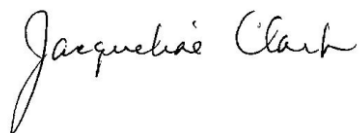
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CERTIFICATE OF COURT TRANSCRIBER

I, Jacqueline Clark, hereby certify
that I have transcribed the foregoing and it is a true and
accurate transcript of the technical conference in this
matter, M13133.

A handwritten signature in cursive script that reads "Jacqueline Clark". The signature is written in black ink and is positioned above the printed name.

Jacqueline Clark

Dartmouth, Nova Scotia