

ONTARIO ENERGY BOARD

FILE NO. EB-2025-0065 Enbridge Gas Inc.

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DATE: September 16, 2025

EB-2025-0065

THE ONTARIO ENERGY BOARD

Enbridge Gas Inc.

Application to review five-year gas supply plan

Technical conference held in person and virtually

from 2300 Yonge Street, 25th Floor, Toronto, Ontario,

On Tuesday, September 16, 2025, commencing at 9:30 a.m.

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DAY 1

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IAN RICHLER Board Counsel

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CLEMENT LI Building Owners and Managers Association Toronto

NICHOLAS DAUBE Ginoogaming First Nation

DAVID STEVENS Enbridge Gas Inc.

RICHARD WATHY

ANGELA MONFORTON

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Tuesday, September 16, 2025

--- On commencing at 9:30 a.m.

I. RICHLER: Good morning. Welcome to the technical conference for EB-2025-0065 concerning Enbridge Gas Inc.'s five-year gas supply plan.

My name is Ian Richler, and I am counsel with the OEB. I am joined by Catherine Nguyen, the case manager for this application, and Tiara Fearon, the hearings advisor. There may also be others from OEB staff who participate from time to time. As the first order of business, Ms. Fearon is going to recite the land acknowledgement.

LAND ACKNOWLEDGEMENT

T. FEARON: Good morning, everyone. The Ontario Energy Board acknowledges that our headquarters in Toronto is located on the traditional territory of many Nations, including the Mississaugas of the Credit, the Anishnabeg, the Chippewa, and the Haudenosaunee and Wendat peoples. This area is now home to many diverse First Nations, Inuit and Métis people. We also acknowledge that Toronto is covered by Treaty 13 with the Mississaugas of the Credit. We are grateful for the opportunity to gather and work on this land and recognize our shared responsibility to support and be good stewards of it.

PROCEDURAL MATTERS

I. RICHLER: Thank you. A couple of quick administrative matters before we get started. First, this technical conference is being transcribed, and the transcription will form part of the record of the proceeding. For the benefit of the reporter, we are recording today's session, but that recording will not be posted. Also the technical conference will be live streamed on YouTube, so be mindful to mute your microphone when you are not speaking.

We will now proceed with appearances, starting with intervenors. When I call on you, please state for the record your name and who you represent. After that, I will ask the Applicant's counsel to introduce himself and his colleagues in the witness panel.

So let's start with -- it looks like there is only one intervenor in the room. Mr. Quinn?

APPEARANCES

D. QUINN: Yes. Good morning, Ian. Good morning, Enbridge. Dwayne Quinn on behalf of FRPO.

I. RICHLER: Then looking online, I see Mr. Ladanyi.

T. LADANYI: Good morning. My name is Tom Ladanyi. I am consultant representing Energy Probe.

I. RICHLER: Mr. Rubenstein?

M. RUBENSTEIN: Good morning. Mark Rubenstein, counsel for the School Energy Coalition.

I. RICHLER: Mr. Vollmer?

D. VOLLMER: Good morning. Daniel Vollmer, counsel for Three Fires Group and Minogi.

I. RICHLER: Mr. Gluck?

L. GLUCK: Good morning. Lawrie Gluck on behalf of the Consumers Council of Canada.

I. RICHLER: Ms. Wainewright?

L. WAINEWRIGHT: Good morning, everyone. Linda Wainewright on behalf of Six Nations Natural Gas.

I. RICHLER: Ms. Siemiatycki? Apologies if I've mispronounced your name.

K. SIEMIATYCKI: You pronounced it perfectly. Good morning. Kate Siemiatycki, counsel on behalf of Environmental Defence.

I. RICHLER: Mr. Brophy?

M. BROPHY: Good morning. Michael Brophy on behalf of Pollution Probe.

I. RICHLER: Have I missed anyone?

C. LI: Here. It is Clement Li here. Good morning, everyone. Representing Building Owners and Managers Association Toronto.

I. RICHLER: Thank you, Mr. Li. And Mr. Pollock?

S. POLLOCK: Good morning, everyone. Scott Pollock, counsel for Canadian Manufacturers & Exporters.

I. RICHLER: Anyone else? No. Okay. Thanks, everyone.

Mr. Stevens, over to you.

D. STEVENS: Thanks very much, Ian. David Stevens, counsel assisting Enbridge Gas with this application. With me is Richard Wathy. Angela Monforton is attending remotely and will be assisting us by projecting documents as requested.

And with that I will turn and introduce the witness panel. In the front row closest to the window, we have Steve Dantzer, supervisor gas supply plan planning and upstream regulation; then Amy Mikhaila, director of gas supply; and Adam Stiers, manager of gas supply acquisition. In the second row closest to the window, we have Lauren Whitwham, manager, community and Indigenous engagement; and then Jennifer Murphy, manager, energy policy and planning; Gilmer Bashualdo-Hilario, manager, demand forecasting and analysis; and, finally, Steve Pardy, manager underground storage and transmission.

ENBRIDGE GAS INC. - PANEL

STEVE DANTZER

AMY MIKHAILA

ADAM STIERS

LAUREN WHITWHAM

JENNIFER MURPHY

GILMER BASHUALDO-HILARIO

STEVE PARDY

D. STEVENS: Just before we get started, we do seem to have a bit of a technical issue that all the microphones seem to be stuck on.

I. RICHLER: Okay. Maybe we can -- why don't we pause for a minute and see if we can resolve that.

D. STEVENS: It seems to be -- it's certainly true of this row here and all of the witnesses. Is that true of the back row too?

I. RICHLER: Is that better now?

D. STEVENS: Well, yours is off. Ours -- mine still seems to be on.

I. RICHLER: We will just take a 5-minute break and go off the record and see if we can get this resolved.

--- Off-record Discussion

Apologies for the delay. Anything else, Mr. Stevens?

D. STEVENS: No, that is it.

I. RICHLER: Okay. Mr. Quinn, over to you.

PRELIMINARY MATTERS

D. STEVENS: Oh, I am sorry. I should just mention for the record in case folks didn't see the prior e-mails that two of our witnesses are available today but not tomorrow. So that is Ms. Whitwham and Ms. Murphy. So in general, those are the witnesses who would speak to Indigenous engagement and to the aspects of the demand forecast that have to do with energy transition adjustments.

I. RICHLER: Okay. Thank you.

Mr. Quinn, you are first on our list today.

EXAMINATION BY D. QUINN:

D. QUINN: Yes, thank you, Mr. Richler, and good morning again to the Enbridge panel. I hope we can have an informative discussion over the next couple of days, but I think we will start in the beginning with FRPO-1, please.

I thought what I would like to do is understand your answer, and then get back to where I was trying to go, and hopefully we can meet in the middle with something that makes some sense for the Board.

So if we can go to the determination that is found in your response, it would be found in the attachments. We can start with attachment 1, I guess, is the EDA. So FRPO-1, attachment 1, page 1. I think it is page 1. Sorry, FRPO-1, attachment 2, page 1, EDA. Do you have that? Okay. Can we start just with how the supply cost is determined in your evaluation?

A. STIERS: Good morning. Adam Stiers. I will -- so the commodity cost, Dwayne, is the ten highest spot prices occurring over the past three winter seasons taken from Platts.

D. QUINN: Well, that makes a little more sense now. I don't see -- is there a footnote that said that or...

A. STIERS: I believe we might have some explanation elsewhere, but I would have to look that up for you.

D. QUINN: I would just -- and maybe more importantly, if we get to a meeting of the minds here, we can make sure people understand the source of the information because I couldn't figure it out. That does make some sense, but I am not sure -- why is that chosen?

A. STIERS: Pulling the ten highest spot prices?

D. QUINN: Yeah.

A. STIERS: Well, from a design day perspective, we are focused on what could be the peak pricing there.

D. QUINN: Okay. So we are -- just to make sure we are grounded here, this is at Empress?

A. STIERS: In the case of long haul?

D. QUINN: Yes.

A. STIERS: Correct.

D. QUINN: So your ten highest spot prices over the last three years and --

A. STIERS: Three -- sorry, just to correct, three winter seasons.

D. QUINN: Three winter seasons, okay. And it was over $10 -- oh, in 2022. Okay. I see. All right. Okay. That is helpful. Then if you could help me, then, with unitized demand charge.

A. STIERS: So I think we explained this one as well. So the demand in commodity charges for the unitized demand charge would be taken from the toll schedules.

D. QUINN: Yes, I would trust that they are. So that is just simply the toll from Empress to the EDA?

A. STIERS: I believe so.

D. QUINN: I would like to have one of us have confidence in that.

A. STIERS: Subject to check, yes.

D. QUINN: Okay. All right. Thank you.

Commodity charge, I trust, is simply fuel?

A. STIERS: Whether or not there is any variable charges associated with any of the options, the fuel charge is located to the right in the final column.

D. QUINN: Sorry. I got ahead of myself in the script, thank you.

A. STIERS: No problem.

D. QUINN: So the commodity charge, there is zero commodity charge for any, except for your third party, and I just wanted to land there for a moment.

A. STIERS: Sure.

D. QUINN: I see if we look at third party, you have used the Iroquois cost. So your third party comparator is a peaking service contract that sources gas at Iroquois. Is that what I am --

A. STIERS: That is the assumption here, yes. Or that at least it is priced based on Iroquois.

D. QUINN: And the unitized demand charge, where would that originate?

A. STIERS: It is based on the weighted average of all offers that we received in the most recent RFP conducted in the previous fall. So where we have done a third party option in any of these tables, it is taken from the average of all offers received.

D. QUINN: Okay. That is helpful. And there is a commodity charge associated with that which I thought a little strange, but maybe you can clarify that.

A. STIERS: It is representative of the offers again received, which can be a combination of demand or commodity charges.

D. QUINN: So when you are averaging them, you just do a simple average of each category, unitized demand and commodity, or are these linked to the bid? So in other words, if you have a -- shipper A or marketer A gives you one demand charge and one commodity charge, do you keep those together for the purposes of creating your average?

A. STIERS: Yes. We use a weighted average across both of those.

D. QUINN: But you keep the demand and commodity the same? Okay.

A. STIERS: Proportionally.

D. QUINN: All right. So then we drop down into the table below. I am trying to understand what you are trying to accomplish with this table. Maybe I will just start there. What are you trying to show?

A. STIERS: So we are trying to show if you were to take the design day shortfall and multiply it by the supply cost and the number of days, you are coming up with your demand -- or, sorry, your demand cost, I should say, and your number of days, we are just showing the aggregate cost of each of the categories. Supply is obviously the point of supply, the commodity cost, and then the variable charges would be your commodity charges, if any, as well.

D. QUINN: So why was shortfall used as the starting point?

A. STIERS: Because this is meant to be a comparison for design day purposes.

D. QUINN: So you have used a forecasted shortfall to be demonstrative of how you would assess it?

A. STIERS: That is right.

D. QUINN: Okay. That makes a little more sense now.

Okay. I think some of this -- and I think it would be helpful because it was referenced in other interrogatories, but if we can move to appendix C in the evidence that describes your -- now, this is on CDA, but I am more interested in the process.

Okay. Now, first off -- and I am trying to find the reference, but it refers to a base case. Can you describe what the base case is in this holistic analysis?

S. DANTZER: Good morning. Steve Dantzer.

The base case effectively is the gas supply plan without contracting for the design day shortfall. So the default is really, in the base case, it fills the shortfall with peaking supply. From there, the alternatives are compared to that base case.

D. QUINN: Okay. I am going to walk through this hopefully in a way that I can understand it better, but is the base case, then, the gas supply plan? And is that gas supply plan, at this juncture, a summation of your existing contracts that are in place and then -- I don't want to -- let's say it this way: Then you just run send out and see what more assets you might need to meet your demand?

S. DANTZER: Yeah, effectively. So we are running send out, again, for the Enbridge CDA in this case, that includes the various contracting alternatives. So if it was a long haul alternative that we were considering to fill the shortfall, that would be the scenario, and we would compare that -- the results of that against the base case. All existing contracts are including its existing gas supply plan.

D. QUINN: So those are your fixed parameters in your analysis, and you are saying, okay, and we are left with X demand in these -- in this geography, and then you run send out to optimize?

S. DANTZER: Correct. You are effectively redoing the gas supply plan under these -- under the various alternatives that are available to meet the shortfall.

D. QUINN: So when you do the supply option analysis summary that leads into your gas supply plan, are you just extracting some output from send out, or is that a different process to create the tables that you put into the gas supply plan?

A. STIERS: Sorry, Dwayne, the supply and service option analysis, you are referring to the table starting at table 15 that you had referenced in your questions?

D. QUINN: Yes.

A. STIERS: So those are two distinct exercises. We do not run through everything that Mr. Dantzer just walked you through for each of those. And I would say the logic behind that is, in part, the ultimate availability of those options. Most, if not all, of the options that were in those tables, you would see on the bottom right-hand column or one of the last columns, it identifies the availability or not of the options. And in almost all cases, there was no availability.

S. DANTZER: I would just add to that, Dwayne, just to be clear, I should have said appendix C, this holistic analysis that we've completed, considers available contracting options only.

D. QUINN: Okay. Well, it's said differently, and we are not going to be able to run a send out here, but don't you just set your parameter in send out to say "capacity available/not available" so it is not an option for the purposes of optimizing?

S. DANTZER: Correct. Effectively, we are looking for alternatives to meet our shortfall that are available in assessing those through the gas supply plan.

D. QUINN: Okay. So I am trying to reconcile your answer to Mr. Stiers' answer in terms of two separate analyses and where they come together in terms of output cost for the purposes of your gas supply plan.

A. STIERS: I might leave it to others to comment on the last part of your question, Mr. Quinn, as to cost and reconciliation between the two, but, ultimately, I think each is distinct and trying to provide insight to the Board in a slightly different manner or purpose.

The supply option analysis, I would say, has a longer shelf life or has been around for a little bit longer is my understanding, and the analysis in appendix C is somewhat unique or a new add to the gas supply plan, although the process itself and the work that Mr. Dantzer described has been around for a long time. So I think there -- my answer is it is -- they are distinct analyses meant to inform the board and parties.

A. MIKHAILA: Sorry, Mr. Quinn, I might also add that the FRPO-1, attachment 2 that you had just pulled up and were asking about those costs of, those are the same costs that you will find in Table 14. We just wanted to show how -- we wanted to -- FRPO-1, attachment 2, provides the detailed calculation that is included in the supply service option evaluation of table 14. So you can understand how those numbers were derived in that table.

Recognizing that all these options are not available, we don't do the holistic analysis by running each option through the gas supply plan. When we have available options, that is when we will complete a holistic analysis to determine the lower cost or total gas supply impact of available options.

D. QUINN: Thank you for your answer. I will digest it with the transcript, but I don't have the resources to pull table 14 up at the same time, so I will do that later. Thank you.

What I would like to do, then, is just go to the -- and on appendix C, page 6 and 7, just pause on those for a moment. So I see -- maybe I need to just flip up to page 5 first because the capacity that is listed in the alternative for the first four of them is 84,457 GJs per day.

Now, I scroll down to page 6, and it is "Alternative cost variance". Again, I start out asking about base case. Is your base case a case where you don't meet that additional demand that you are seeking?

S. DANTZER: Correct, yeah. Like I said, the base case assumes -- send out, the optimization model, will initially assume a shortfall being filled with peaking supply. And so that is why when you see that first -- that column A, the alternative to base case being zero in that case.

D. QUINN: If it is met with peaking supply, then I don't understand the "not applicable" or "NA" in the far column.

S. DANTZER: Well, the intent here is to compare alternatives to the base case, right.

D. QUINN: Okay. All right. I will accept that. Certainly. Thank you.

So then in lines 2 through 5, you have got alternatives 1 through 4, and you have variable alternative costs. And I was trying to make sure I understood that because you are seeking the same amount of capacity, but the cost is changing. Can you help me with that? Is it simply the scenarios that were above that were -- in the scenarios above, you have got capacity available, and you have got different months associated with it. If we are trying to meet a peak day type of approach, I was confused that the costs change over those different alternatives when you are seeking the same capacity.

A. MIKHAILA: From the third party provider, we were given different prices for the supply under the different scenarios of the months available. So there was a different price for the capacity from December to March than there was from January to March and January and February as provided on page 5.

D. QUINN: And these are -- each of the figures in column A are all total cost of the alternative even if the amount of months they cover vary?

A. MIKHAILA: Yes. Column A of page 6 provides the incremental cost of the gas supply plan relative to those options. So if the supply was only -- if the supply was going to be provided to us for four months, that was the gas supply plan cost impact of that scenario.

D. QUINN: Okay. It might become a little clearer, then, if we move to page 7 and start at line 1. So in the top, you have alternatives 1, 2, 5 and 6. And so in column A with alternative 1, you have the total supply of 30.9. Where is that supply? Is it at the delivery area in the -- in this case, CDA?

A. MIKHAILA: For option -- or alternative 1, it is long haul Empress to the Enbridge CDA, so that supply is being procured at Empress and transported to the Enbridge CDA year round for the 365 days of the year.

D. QUINN: So it does for most -- well, for the summer months, the gas is assumed to go to storage?

A. MIKHAILA: Yes. The optimization model will assume, you know, 100 percent load factor of the supply, and then optimize it as needed to storage, if necessary.

D. QUINN: Okay. Are then the storage costs, the space and deliverability, associated with that alternative? Are they included in your total annual supply quantity?

A. MIKHAILA: Sorry, on line 1?

D. QUINN: Well, in your cost that you had in your previous table on page 6.

A. MIKHAILA: The gas supply plan doesn't include the costs of the cost-based storage or market-based storage, for that matter, because those are fixed costs. So they are not -- the costs don't change amongst these alternatives.

D. QUINN: Okay. I struggle to understand that because your alternatives 5 and 6, are they not just winter deliveries?

A. MIKHAILA: Alternatives 5 and 6 include long haul from Empress year round as well as part of the year deliveries, December to March.

D. QUINN: Okay --

A. MIKHAILA: There is a long haul component --

D. QUINN: Okay. There is --

A. MIKHAILA: -- and a component that is just the winter.

D. QUINN: Excuse me. I don't want to interrupt, but I didn't phrase my question clearly. In scenario 1, you have -- you said 365 days of supply at 84,000, roughly. But then in alternatives 5 and 6, you have third parties bringing in a portion of that 85 just for the winter months and only 20,000 from TCPL. So how do you say your storage doesn't change when you are -- you have only got to store 20,000 in alternatives -- well, I will focus on alternative 5, and yet in alternative 1, you have got to store for 365 days?

S. DANTZER: So, yeah, the impact on storage utilization is considered under each of these scenarios.

D. QUINN: Is it quantified? That was my question. Is it quantified, then --

S. DANTZER: It is quantified.

D. QUINN: And it is in page 6 above?

S. DANTZER: Well, it -- the impacts of storage utilization are included when we run the optimization scenario under each of those scenarios, but there are no incremental storage costs --

A. MIKHAILA: The --

S. DANTZER: -- as a result.

A. MIKHAILA: Sorry, Steve. The storage utilization considerations are included on line 4 of page 7 where we show the reduction in annual inventory cycled. But the cost of storage is not impacted by these alternatives because that cost is our own facility cost. Under all scenarios does not -- the cost of storage does not change.

D. QUINN: I am sorry. I don't want to get into debate here, but if you have 84,000 GJs a day coming to you in the summer, you are going to need, from an aggregate excess point of view, more storage than if you have 20,000 coming at you 365 days and only -- and 64,000 coming to you for selected months.

A. MIKHAILA: The impact you are referring to is being considered in the optimization model by reducing Dawn purchases as an -- in lieu of this supply coming in. So the optimization model is recognizing the additional supply under these alternatives, and some were receiving more supply than others, and it is adjusting other factors in the gas supply plan to account for that.

S. DANTZER: There is no impact to aggregate excess under any of -- right? Demands aren't changing.

D. QUINN: No.

S. DANTZER: We are talking about supply.

D. QUINN: Yeah.

S. DANTZER: And so the model considers the impacts of supply on any delays of storage, Dawn purchases, use of transport. That is all reflected in the -- ultimately all reflected in the costs being evaluated under each scenario.

D. QUINN: So you are saying the storage amount for the CDA is absolutely fixed under every scenario?

S. DANTZER: Correct.

D. QUINN: Okay. Well, now I understand it better, but I need to understand, then, where your costs go. So if we walk through the scenario 1, total annual supply quantity of 30.9, so that, as we have talked about, goes to the delivery area. That is where its prime delivery point is, but it is diverted to storage for parts of the year.

S. DANTZER: Parts of the year, yes.

D. QUINN: Okay. So your reduction, then, in summer purchases, I note he has 20.5, correct?

A. MIKHAILA: That is correct.

D. QUINN: Okay. So if I were to net 20.5 from 30.9, 30.9 being the amount of quantity delivered, but now you have reduced the amount you buy in the summer by 20.5, I come up with 10.4 as the difference between those two, and yet what is shown here is total summer Dawn purchases, 2.6. Was it before 10.4 plus 2.6? Like, this is where I struggle. I was trying to follow your thinking and --

A. MIKHAILA: Summer purchases were the sum of the 2.6 plus the 2.5, so they were previously 23.1 PJ reduced by 20.5 PJ so that under this scenario, our summer purchases are only 2.6 PJ at Dawn.

D. QUINN: Sorry. We may be working at cross purposes, so I am going to try to follow what you are saying. What are the purchases at Dawn in the base case?

A. MIKHAILA: 23.1 PJ.

D. QUINN: Okay. And now you are bringing in 30.9. Is it possible by way of undertaking you can take column 1 and show the math as to what the base case is and what the alternative one is that show the difference in what you're analyzing to be able to say -- and I am assuming this, and I am looking for your confirmation -- that all costs are treated at the margin? Whatever is different from your base case are your costs, so all that math should work out such that what costs -- how is gas supply being provided and what is the incremental cost from the base case? Can you do that?

D. STEVENS: So we are looking at column 1 of -- is this page 7, Dwayne, of appendix C?

D. QUINN: Yes, it is.

D. STEVENS: And your question is what is shown in the base case in terms of each of these rows, and then what is the associated cost?

D. QUINN: What is the -- yes. Starting with the base case, David, I heard from Ms. Mikhaila that you had a total Dawn summer purchases of the sum of 2.6 plus the 20.5, so what is that? 23.1. That is your base case for summer supply.

But then as we move down, we have got a reduction and annual inventory cycle of 4.9. And I am at a loss as to how all of those numbers reconcile to you're buying the same amount of gas and the same amount of gas is being demanded or consumed, and all the math hangs together.

So if you can show the base case, show the math for the changes and then what the changes associated with it are. I am starting with column 1, but I would like to see and understand the process and possibly be informed enough to do at least column 1 and, let's say, column 5. I am struggling with my own memory. Which one was chosen, was it 5 or 6?

A. MIKHAILA: It was number 6.

D. QUINN: Okay. So if you do number 1, and then do number 6 for the purposes of comparison, then we can have the alternative considerations at the margin relative to the base case.

A. MIKHAILA: Mr. Quinn, may I have Ms. Monforton please turn up Exhibit I.2-CCC4, page 1, attachment 1.

D. QUINN: Sure, as long as we can put a tab on this one here to come back to it.

A. MIKHAILA: This interrogatory asked for kind of a more detailed explanation of the incremental costs relative to the base case. So you can see here it is a five-year sum of costs for the impact of those alternatives to the gas supply plan which nets to column G, being the alternative cost to the base case.

I understand your undertaking. You are trying to tie the costs, like the incremental cost, you are interested in the incremental cost of these alternatives, but trying to tie it to summer purchases and storage utilization that we have on page 7. I am just not sure how you would like that presented.

Like, these -- we can -- the attachment 1 at CCC4 provides the total gas supply plan cost in each of those years and what the total cost of that plan is under each of the alternatives, and we can break that out into supply, transport and storage if that would be helpful.

D. QUINN: I was going to go there because I don't see storage listed on the (indiscernible) and you have informed me as of this morning that some of these differences in the cost were relative to reduced summer purchases, and I don't know where that comes from. So if you could show the math and the source of where you get your numbers, then your analysis would make sense to me and, hopefully, eventually to the Board.

D. STEVENS: So to be clear, are we suggesting that we would -- that Enbridge would provide a further version of the table at CCC-4, attachment 1 that breaks out the supply, transportation, and storage components of the costs set out in lines 1, 2, and 6?

D. QUINN: I think scenario 6 is actually line 8, if I'm --

D. STEVENS: Oh, I am sorry. I am looking at the alternative numbers. I agree. Sorry. So it is lines -- you are quite right -- lines 1, 2, and 8.

D. QUINN: Okay. And does that reconcile with your understanding, Ms. Mikhaila?

A. MIKHAILA: Yes. The one thing I just want to comment on is, again, the gas supply plan doesn't have the cost of storage. It recognizes the utilization of storage, but that fixed cost is the same cost under all these scenarios. So what you will see in changes in storage cost is carrying costs of gas in storage, which will change depending on how storage is utilized.

D. QUINN: I am starting to understand that, and so if you can just put that into the caveats in accepting this undertaking, I trust, Mr. Stevens?

D. STEVENS: Yes. To be clear for the record, Enbridge Gas will provide a further version of the table at Exhibit I.2, CCC-4, attachment 1, where Enbridge sets out the supply, transportation and storage costs that are included in lines 1, 2 and 8 of that table, and Enbridge Gas will explain, to the extent that it's helpful, what is included under each of those three components.

I. RICHLER: So let's record that as Undertaking JT1.1.

UNDERTAKING JT-1.1: TO PROVIDE A FURTHER VERSION OF THE TABLE AT EXHIBIT I.2, CCC-4, ATTACHMENT 1, WHERE ENBRIDGE SETS OUT THE SUPPLY, TRANSPORTATION AND STORAGE COSTS THAT ARE INCLUDED IN LINES 1, 2 AND 8 OF THAT TABLE, AND EXPLAIN WHAT IS INCLUDED UNDER EACH OF THOSE THREE COMPONENTS

D. QUINN: Thank you.

Just before we leave this, and recognizing the CCC interrogatory, Mr. Gluck is online. Is there any questions of follow-up, Mr. Gluck, that you would like to ask now? I just wanted to give opportunity.

MR. GLUCK: No, I don't have any questions right now. Thanks, Dwayne.

D. QUINN: Okay. Okay. Thank you.

If we can go back to page 7 of appendix C, as I asked. Thank you. Ms. Monforton is always quicker than I am. I just -- I am understanding a little bit more about the total summer Dawn purchases that are reduced, but then I come to this reduction in annual inventory cycle at 4.9. Can somebody build the math for me there as to how these changes above in lines 1 and 2 reconcile to the reduction that is in line 4?

A. MIKHAILA: I don't think we have the information to do that right here at the moment.

D. QUINN: Well, follow my logic, then, if you would. You've told me that you have reduced your summer purchases by 20.5. So, again, if I deduct that from the amount of extra gas you are buying at 30.9, I get 10.4. But then I see a reduction in annual inventory cycle as 4.9, and that is where I get lost.

A. MIKHAILA: If I had to take a stab at the answer, but maybe we can confirm this, there would also likely be a reduction in winter Dawn purchases.

D. QUINN: And is that reflected in your cost that you are going to provide in the undertaking just taken?

A. MIKHAILA: Yes, it would all be in the total cost comparison. Page 7 was really some of the key things we looked at when assessing the alternatives available to us, and one thing we were conscious of was summer Dawn purchases because of the flexibility we need in the summer months if we were to come out of a warm winter.

We recognize that sometimes we don't make those Dawn purchases, even though they're planned, depending on the inventory levels at the end of a warm winter. And so when we were looking at those alternatives, we were interested in how summer Dawn purchases were impacted by the alternatives.

D. QUINN: That's helpful. And, again, if you could show the reduction in winter purchases and the associated cost reduction, I trust that comes from that, I think we would all be better informed, so thank you for that.

I don't want to leave this page because it is -- you can lead me to some other evidence, if you'd like. We are dealing with the CDA, so I will stick with the CDA. How do you value the deliveries at the CDA that you are getting from the 84,000 relative to, let's say, scenario 6, which was chosen, and you only have 40,000? How do you value the difference in STS credits -- well, let's start with the gas is there on a peak day. How do you value that?

A. MIKHAILA: Sorry, Mr. Quinn. I am just not sure what you are asking.

D. QUINN: Okay. So we will walk through this slowly. The gas is coming from Empress, and it's landing in the CDA notionally. It has to be diverted in the summer into storage if the demand isn't there.

However, in the winter on a peak day, you have 84,000. In scenario 6, you have 40,000. You are missing the -- not missing, but since you say this is their demand shortfall, there is 44,000 that is actually coming through this third-party assignment.

When I am looking at the differential, I am thinking, okay, well, what's the differential here? And what I come up with is STS credits that were injected during the summer and are available to help support deliveries from Parkway -- well, from Dawn through Parkway to the CDA, and is that included in your differential cost?

A. MIKHAILA: I just want to be clear, though, that under alternative 1 and alternative 6, there -- both cases, there is 84,457 GJs arriving at the CDA in the CDA.

D. QUINN: Right.

A. MIKHAILA: One is coming from Empress, and one is coming from Niagara.

D. QUINN: Right. So from an STS point of view, do you track -- or in this case here -- the impact, the cost impact of STS injections, which will be higher with alternative 1 than alternative 6, and what's the value of that to the company?

S. DANTZER: There is no incremental STS considered in any of these alternatives.

D. QUINN: Why would that be?

S. DANTZER: Because we didn't assume any increase in the availability of STS.

D. QUINN: But if you are taking 84,000 a day, you agree with me that you would have more STS credits built throughout the summer available to become withdrawals in the winter?

S. DANTZER: No. I mean, we are limited by our existing STS contracts in this case.

D. QUINN: So you need change --

S. DANTZER: There is no change in our STS contracts as a result of any of these scenarios.

D. QUINN: I am not talking about the contract. I am talking about the injections you get throughout the year. The contract remains the same. You are short on STS credits, are you not? Do you get through the winter without paying a premium for STS from your storage?

S. DANTZER: One second, please.

D. QUINN: Okay. I -- just as you speak about it, my asking these questions is somewhat dated. If you somehow have improved your FT position such that you do get through a winter with sufficient STS credits, then you can tell me that. But I just -- last it was on the record, you were short in STS injection credits and had to pay the premium for withdrawal in the winter.

S. DANTZER: Sorry. Just to clarify, are you referring to, like, an STS overrun charge when you say --

D. QUINN: Yes.

S. DANTZER: Okay. Again, there was no incremental STS cost, no incremental STS overrun charge reflected in any of these scenarios. We utilize all of our STS injection and withdraw capabilities today, and that was assumed under these -- all of these scenarios as well. So, again, no change -- no incremental change to the STS.

D. QUINN: None was analyzed?

S. DANTZER: No. No, no. We -- we ran the gas supply plan according to the existing contracts, including STS, but no incremental change. We didn't get any incremental STS attributes through contracting for long haul, and so there was no incremental consideration made.

D. QUINN: So if we just went with a simple scenario of 84,000 delivered, 365 days, or 40,000 delivered, you are saying there is no change in your STS position?

S. DANTZER: That is correct.

D. QUINN: Okay. We may come back to that. I will accept your answer. Thank you.

Okay. What I would like to do now, if I may, just so that we have clarity on another cost measure, I submitted a spreadsheet last night, admittedly late. As opposed to trying to ask you to create it, I thought I would create something -- thank you very much, Ms. Monforton.

I don't know if we should mark this as an exhibit, Mr. Richler. I just -- I put it in through the RESS system, but possibly giving it an exhibit will help.

I. RICHLER: Yes. Let's mark this as Exhibit KT-1.1, and it's a table with the heading "Design Day Delivered Cost to EDA".

EXHIBIT KT-1.1: TABLE WITH THE HEADING "DESIGN DAY DELIVERED COST TO EDA"

D. QUINN: Thanks for pronouncing it properly in spite of my spelling error.

So I was trying to just come up with a format as to what I was seeking when we didn't connect in FRPO-1, and the landed gas analysis, I know, has been around, and, frankly, I was around when Union first started producing it. But what I was trying to seek, and I think it would be helpful for the Board to understand, is what is the cost on the design day? So the supply cost that I have -- sorry -- I am going to start maybe from the left-hand side.

So I have taken the same different alternatives that were produced, and this is for the EDA specifically, but I will be asking for other delivery areas. When you take -- that actually helps. Thank you very much.

When -- the supply point of receipt or basically where you are going to receive your gas at the outset, I use that plus the point of delivery being the EDA. And I use the supply cost from this -- the same FRPO-1 table that was produced by CF. You can reconcile that and double-check it, if you'd like. And I used your foreign exchange just to be able to stay in Canadian dollars, I think, which is helpful for all of us, to come up with what would the starting point be for the supply cost, assuming you have contracted for that capacity at the respective Empress, Dawn, Niagara and Iroquois locations.

So starting with that supply point, what is the cost, the total delivered cost on a peak day across each of those alternatives? And on -- in the far-right-hand column, I have put a design demand cost of delivery area, which I think would be your demand components, but, frankly, you can correct it, change it, or apply whatever, and please just note your source, if you would.

Would you be able to fill out that table so we have an essence of what a -- the cost looks like on a design day versus an average day?

A. MIKHAILA: Mr. Quinn -- Ms. Monforton, if I could please have you turn up Exhibit I.1-FRPO-1, attachment 2. I think we have already looked at it today. The challenge I find with what you have asked to do here is -- is having us provide a unitized cost of a design day analysis, which is -- this looks very similar to what we do for the average day. But what we do on the design day is the total annual cost, which we have provided in -- for the EDA in attachment 2 to FRPO-1.

The challenges under these five alternatives, you are not necessarily procuring the supply for all days of the year on a design day.

D. QUINN: Say that last sentence again. I don't -- I was following you up to that point, but I was forming a question.

A. MIKHAILA: Sure. We don't necessarily procure the supply in this manner for all days of the year to meet a design day. So when -- under this type of request, we are unitizing the full cost per -- per unit of molecule, but we don't necessarily procure that molecule each and every day of the year to meet a design day.

D. QUINN: But if you met your demand through long haul -- we just went through there's the CDA, and I don't want to be throwing off CDA and EDA. But if you are deciding that in the CDA scenario, you are contracting for 84,000, you are procuring that molecule every day of the year and the design day?

A. MIKHAILA: In a long haul scenario, yes, and I think that we've described that at Exhibit I.2-FRPO-3. We have indicated in a long haul scenario, the optimization model will procure the supply every day of the year, but that is not necessarily the case in a short haul scenario.

D. QUINN: No, it isn't, but that's the difference in the value. I mentioned the STS, and I've accepted the answer for now that you are not looking at STS. But the gas lands where it is needed on a design day, and, in essence, that has value as opposed to having to transport it from somewhere else.

So I am asking that you would follow that same logic and assume that you bought the gas for the 365 days a year for the EDA, and then you can do the short haul from Dawn or Parkway -- sorry -- Dawn or Iroquois in this approach to see what the measure would be in terms of effectiveness of meeting a design day with each of those alternatives.

A. MIKHAILA: But, for example, in the case of third-party peaking service, that service itself is not procured 365 days of the year.

D. QUINN: Okay. Then put "not applicable" across the bottom line, and put that in the response. I would be happy with that.

D. STEVENS: Sorry. To be clear, Dwayne, in order to have this comparison be shown on apples-to-apples basis, you are interested in simply seeing the design day options that contemplate -- comparison of design day options that contemplate supply each day of the year?

D. QUINN: Yes.

D. STEVENS: And I am just thinking, for example, of the CDA option we just looked at that had a bunch of -- the menu included, you know, part that was long haul and part that was seasonal, I guess. It wasn't peaking, but it was seasonal. So I just -- I am just not sure what this comparison shows us, that it will just be a partial picture.

D. QUINN: Well, I would counter Mr. Stevens that the average day is only part of a picture because it doesn't take into account the fact that a lot of your costs are born as a result of design day demand. And so if we measure alternatives and include a view to design day demand, I think we may have a more fulsome, holistic picture of the cost of the utility and the ratepayers.

A. MIKHAILA: I think that is what I was trying to share about FRPO-1, attachment 2, is it is, I think, essentially what you are asking for, except in this case, it only assumes four days of supply. So it gives an annual cost of these alternatives, assuming four days of supply, which is --

D. QUINN: Well, I would say, okay, do four days of supply -- sorry. I'd like this -- you to fill this table, and then we can talk about a second table that uses four-day supply for the coldest weather or the coldest days or prices in the last two years. You have done three years because that brings in the anomaly of 2022, and to me, that is cherry-picking the supply cost. So I am asking for two years for that.

So let's deal with the -- what I would like to have is a design day cost based upon annual delivery of -- and, yes, there will be storage implications. I am not asking for that in this table. But if you can fill that table in, then we can talk about getting four days of supply and how we would measure that.

D. STEVENS: Sorry. To be clear, Dwayne, we are looking at Exhibit KT-1.1?

D. QUINN: Yes.

D. STEVENS: And you are asking for the annual cost for the first four rows --

D. QUINN: It's --

D. STEVENS: -- reduced to a cost per GJ?

D. QUINN: Yes. Thank you.

D. STEVENS: And that's just the annual costs associated with these design day alternatives?

A. MIKHAILA: And can I just clarify. The supply costs that you included in there were the supply costs for the first, I guess, gas year, November '24 to October of '25, and you would allot just that one-year view of value of alternatives.

D. QUINN: That is what you put in your landed gas cost analysis, is it not? I think I just tried to follow your formula for the --

A. MIKHAILA: We -- we have provided all five years of gas cost, and in our landed cost analysis on the average day, we used the average annual gas supply cost for the forward five years. So it just depends on what view you would like.

D. QUINN: I put in the supply cost based on '24/'25. I think that is reasonable, but if you want to put in the average of the five years, just note that -- that that is the change. The challenge is I think we just need to keep our foreign exchange fairly constant, so if you use that same foreign exchange because most of the other costs are in Canadian dollars.

D. STEVENS: I think, Dwayne, without stipulating to the usefulness of it, we can fill out the missing information in KT-1.1 for rows 1 to 4. We won't be filling in row 5 because it is a different -- it is a different arrangement, given that it is only several days.

D. QUINN: I understand the distinction, yes. I can accept that. Thank you.

D. STEVENS: But we can do as I just indicated.

I. RICHLER: That will be JT-1.2.

UNDERTAKING JT-1.2: TO FILL OUT THE MISSING INFORMATION IN KT-1.1 FOR ROWS 1 TO 4

D. QUINN: And before we leave -- thank you. Sorry.

Before we leave this page, I would like and I would be interested in the supply cost. Your assumption is four days. I will accept that as four days. But I would like it for the last two years, so you can put a second undertaking, if you would accept it, and put the supply cost of the receipt point for the four -- four days. You can take the four highest price days, if you want, in the last two years for each of those points and complete the table again, and that, hopefully, then if we get into concerns about usefulness, as Mr. Stevens referred to it, there would be another view of this type of analysis.

D. STEVENS: Sorry. So we are now back to the table that Ms. Mikhaila was looking at with the four days?

D. QUINN: No. I am using my table, the design day delivery cost to the EDA, but then you can vary the supply cost because, as Ms. Mikhaila said, you can make different assumptions about supply cost, average over five years or just one winter, whatever.

The alternative that was chosen by Enbridge for its scenario analysis was to use the coldest four -- four days of supply, and I am going to say, well, then you take -- choose four days of supply over the last two years, and you take the highest cost for each of those supply points and fill that into the table also, just so we have a sensitivity or a scenario analysis.

D. STEVENS: Sorry. I am sure that I am catching up versus everybody else. I had understood the table at KT-1.1 to be showing the full, you know -- a unitized version of the full year cost, which I would have thought was different than simply looking at the four coldest days. In other words, this is sort of the average supply cost over 365 days.

D. QUINN: But if you are contracting in this manner for the first four alternatives, you have that contract for 365 days, so you can calculate unitized fuel charge, all those types of things. The only variable simply to address the concerns expressed by Enbridge was to have the supply cost, not an average cost for the winter, but a peak cost for design day. So I am suggesting to use a supply cost that --

A. MIKHAILA: Sorry, Mr. Quinn.

D. STEVENS: That wouldn't represent what actually happens.

A. MIKHAILA: That wasn't the concern I was expressing. I was -- I was expressing the concern of unitizing these four scenarios where you may not procure the supply in 365 days of the year, and that is why in FRPO-1, we provide the annual cost, not a unitized view of it.

D. QUINN: You would still have that cost every day of the year nonetheless?

A. MIKHAILA: Not the supply cost.

D. QUINN: No. For the demand, unitized demand cost.

A. MIKHAILA: Yeah.

D. QUINN: So for the four days of supply, we are assuming it is a peak day. We are assuming you are going to utilize it. You are going to then have any associated commodity charge, certainly a fuel charge. I am just saying do the table again, but just submit the last two years --

A. MIKHAILA: But if you add a unitized demand cost to a unitized supply cost, it is not representative of the full cost.

D. QUINN: It is not the full cost, but it is -- it is a -- just like as your landed gas cost is not a full cost, it is a unitized cost. I am just saying unitized on a demand -- sorry -- on a design day, not an average day.

D. STEVENS: So if I can try this, Dwayne, are you asking to see what is the total delivered cost per GJ and the component parts of it on the coldest four days of the year for these options as opposed to as an average value for each day of the year?

D. QUINN: Yes.

D. STEVENS: Is that something we can do?

A. MIKHAILA: We can do that.

D. STEVENS: So that will be a separate undertaking.

D. QUINN: I just want to be clear. But the four coldest days, you are going to choose the price for over the last two years, not three.

D. STEVENS: Okay.

A. MIKHAILA: Agreed.

D. STEVENS: So just to be clear, Enbridge will provide an alternate view of Exhibit KT-1.1, rows 1 to 4, setting out the cost per GJ of the missing cells for the average of the four coldest days of the last two years.

I. RICHLER: JT-1.3.

UNDERTAKING JT-1.3: TO PROVIDE AN ALTERNATE VIEW OF EXHIBIT KT-1.1, ROWS 1 TO 4, SETTING OUT THE COST PER GJ OF THE MISSING CELLS FOR THE AVERAGE OF THE FOUR COLDEST DAYS OF THE LAST TWO YEARS

D. QUINN: And I do appreciate you walking through so we have clarity. Thank you. And I am saying that upfront as I say the next undertaking I would like to ask is this be done also for the WDA and the NDA. That was part of the original interrogatory.

D. STEVENS: Is that something that is practical to do without -- within our time parameters?

A. STIERS: I believe so. So on a best-efforts basis, yeah.

D. STEVENS: Okay. So we will expand JT-1.2 and 1.3 to include responses for each of the EDA, WDA, and NDA.

I. RICHLER: Thank you.

A. MIKHAILA: And sorry. Just the Enbridge EDA?

D. QUINN: Oh, thank you for the clarification. Yes, I would like the Union EDA. Thank you. So it's Enbridge EDA and Union EDA. Thanks for clarifying. I'll -- once we have that, I'll have further questions.

D. STEVENS: That's -- we can do that.

I. RICHLER: So should we note that as a separate undertaking, JT-1.4 to include the EDA, WDA, and NDA when answering JT-1.2 and JT-1.3?

D. STEVENS: That might be most clear, Ian.

I. RICHLER: So let's do that. JT-1.4.

UNDERTAKING JT-1.4: TO INCLUDE THE EDA, WDA, AND NDA WHEN ANSWERING JT-1.2 AND JT-1.3

D. QUINN: Thank you.

Now, Ms. Mikhaila brought up an interesting point with the EDA. Both Enbridge and Union have respective EDAs. I know somewhere in the responses I read that there has been no integration, for lack of a better term, of the EDAs from a contracting point of view with TransCanada. Is that something that Enbridge is continuing to pursue, or are you not pursuing that at this time?

A. STIERS: Dwayne, sorry. Maybe you can help us. Do you have a reference for that response that you're referring to? I recall the one that you are talking about. I just can't recall --

D. QUINN: I was just asking a generic question. I don't have the reference. I did ask about it somewhere. And I can find it at the break, if you want, Mr. Stiers. And we can --

A. STIERS: I think we have got it. FRPO-14 maybe?

D. QUINN: Actually, in my notes, it says "FRPO-14 integrating EGI Union". Yes, correct.

So still the same question.

A. STIERS: Could you repeat it, if you don't mind? Sorry.

D. QUINN: I understand with the integration, there is integration of staff; there is integration of, you know, gas supply contracts. I understand you are limited by TransCanada's delivery areas. I get that. But when we look at is there optimization efforts, there can be diversions. So if you are delivering gas to one of the EDAs, you may be able to divert some days to the other EDA.

In your gas supply plan, essentially talking to the pipeline who provides these deliveries and asking about what can be done is a starting point. So has -- is the door still open to discussion with TCPL about these opportunities, or has the negotiation concluded with there is nothing that can be done?

A. STIERS: So I think that is what we meant when we closed our response on page 2 by saying:

"In the normal course of managing this portfolio, we seek to optimize such services, contracts, and to reduce the costs or to otherwise benefit ratepayers."[as read]

So as a general term, yes, we are -- we do look at ways to optimize within the way that we -- we are contracted currently. I might -- might toss it over to Steve to see if he has anything else to add there from a plan perspective.

S. DANTZER: Yeah. Certainly diversions between different delivery areas is currently an option, and we do reflect that in the gas supply plan. Now, we are -- there is operational constraints on the main line that do limit the ability to do that, and that has been a reality of -- a recent reality, I would say. But, you know, generally speaking, the demands are what they are. They are not going to change, whether delivery areas change or do not change.

And so the ability -- you know, if you are looking at a consolidated single EDA, the ability to -- certainly there might be changes in utilization of contracts, but we wouldn't see a reduction in contracts or incremental contracts, for that matter. And so we are -- the demands don't change under any scenario, if that is helpful.

D. QUINN: And I get it, the demands don't change. How you contract to meet them can evolve, and I would carefully ask, what about pooling of STS for the EDA? Is that something that you have discussed with TransCanada?

S. DANTZER: Again, I would say generally changes to existing STS contracts are pretty limited. I mean, there was a hearing at the CER that you would be aware of a number of years ago, and so TransCanada's position on STS is, I would say, fairly well known.

And so we do pool Union EDA STS credits as part of -- with other delivery areas, but I think any -- any future changes would be limited.

D. QUINN: My recollection of the CER proceeding -- the CER basically said, not now, you are in the middle of a rate construct. So I am going to leave that one there.

I am hearing, Mr. Dantzer, that it is -- you are pooling credits in this case for the Union EDA. All we can do is encourage a broader look to say, well, it is the same assets, same type of delivery area, not precisely the same delivery point, but similar assets are being used and potentially could be -- have greater utilization or potentially rationalization with some reductions in, let's say, a short haul contract that would be beneficial to ratepayers.

S. DANTZER: Yeah. I mean, I should note too that the contracts that serve the EDAs are on a design day basis. So, again, I don't see a change under any event reducing the requirement for those contracts. Our current -- the contractual abilities of our current STS contracts are currently fully utilized. And so, again, just generally speaking, not seeing opportunity for further optimization of those given that they are already fully utilized.

D. QUINN: Okay. Thank you. I am going to move on to another area. Thank you for having a meeting of the minds. It was accepted through the letter that we -- we exchanged letters, and I trust now, I think, we understand each other better, so thank you. I understand your analysis better for sure. Thanks for that.

What I want to do is -- I think at this point because I understand -- and I don't know if Ms. Murphy can speak to some of this stuff, but I want to make sure I ask questions about the demand side before the end of the day today in terms of my time. So if we can go to FRPO-11, please.

So just generically, I am trying to understand the answers provided. It is properly attributed to the 200 TJs difference, but, specifically, I want to just camp on the CDA, for the moment, anyway.

Yes, I read that there was evidence put in the first phase of the rebasing proceeding about your design day, but I don't understand -- what I don't understand in the answer is what drove the 200 TJ increase going from '23/'24 to '24/'25. Can we start there? What were the drivers?

S. PARDY: So Steve Pardy here. So as you see in response FRPO-11, part A, we have kind of outlined a number of different factors that lead to a difference in the calculation of the demand for the CDA. And then we have talked about kind of different methodologies that were used in preparing the demands between the two different numbers that we are talking about. And also using different base years when we did the calculation, and then also that it was different budget cycles.

So basically, every year when we -- every time we calculate the demand, we use a specific methodology. In this case -- usually the methodology stays the same. In this case, they were different, so you would expect a different answer for a demand using the different methodologies.

D. QUINN: Thank you for the overview, but I think I would like to drill down just a little bit more. And thanks, Mr. Pardy. Sorry, I thought it was Ms. Murphy on the demand side.

But, Mr. Pardy, can you -- I read that response, but I didn't see anything in here that says what changed, first off. So let's walk through this. Your design day remained constant, correct?

S. PARDY: What do you mean by the "design day remained constant"?

D. QUINN: The temperature at which Enbridge would say -- in this case for the CDA, 41.4, subject to check?

S. PARDY: That is correct, yes. I forget what the exact temperature is, but you are correct in saying that the design temperature for, I believe we are talking the CDA here, didn't change.

D. QUINN: Okay. So your design -- the -- and I -- maybe I am going to walk through this a little more slowly. You are still using a regression analysis, are you not?

S. PARDY: We are. So I think the big difference, if you look at the notes there, is prior to rebasing on the Enbridge side, they were using a one and five-year probabilistic method to calculate the demands, and then the stuff we are showing here in the gas supply plan is using kind of that new method that uses the 30-year window for the design temperature. So the methodologies are completely different between the two numbers.

D. QUINN: The methodologies may vary, but your outcome, as I understand it, didn't change because it is 41.4 heating degree days, wind adjusted. Isn't that correct?

S. PARDY: I don't think that -- actually, now that you say it, I don't think that is correct. I think using the one and five year will lead to a different outcome.

D. QUINN: Well, that is not what -- I haven't read that in here. Is that what you are --

S. PARDY: If you look at the note in note 1 in the response.

D. QUINN: Sorry, I don't read a temperature. Are you talking about --

S. PARDY: I don't say a temperature. It says the probabilistic method, one in five year recurrence, without the wind speed adjustment was used to prepare the demands for EBO 2022-02 exhibit -- like, the exhibit that is listed there.

D. QUINN: Okay. What I am going to ask you to do by way of undertaking -- because I understand it is a regression analysis. I don't think much changed in terms of how you do a regression analysis but --

S. PARDY: I think it is completely different.

D. QUINN: Well, okay. Then you get an opportunity to show us how it is completely different, Mr. Pardy. If you could take an undertaking to show us how it was done for the previous year when you established the '23/'24 design day demand for the CDA specifically, and then show the math also for how you did it, including the data, for the '24/'25. And if it is a regression plot, that would be helpful, I think, as a figure so people can understand it, but then point out what things are changing to result in what amounts to approximately 6 percent difference in the CDA -- you don't have to take 6 percent. An incremental jump in the CDA over one year. I would like to understand how that occurred.

D. STEVENS: So we can provide that undertaking. I mean, to be clear, as Mr. Pardy said, while design day may not have changed, the methodologies that are used did change, and that is what is explained in footnote number 1. I mean, my recollection is Union used a coldest day approach, and Enbridge used a one in five recurrence approach. And so when those two things were brought together to be the coldest day back to 1994, I believe it is -- perhaps I had the year slightly wrong -- that is what drove the large part of the change. But if it is helpful to you, we can show the derivation of the prior CDA design day and the current CDA design day. My guess is because the CDA is entirely EGD, that the explanation I just gave will be the driver.

D. QUINN: It may be, Mr. Stevens, so I appreciate you are going to accept the undertaking. And this you can handle separately or with it: What was on the record in Phase I that spoke to the implications of this change from a financial perspective.

D. STEVENS: I don't think that is relevant here, Dwayne. I mean, we have a settlement. It was determined how design day would be calculated going forward. Whether or not that was -- I just don't want to enter into the debate about what was understood and what was simply not in issue for the gas supply plan. We can show the difference between the calculations if that is helpful to you.

D. QUINN: Okay. Let's take that in undertaking, if we can, Mr. Richler.

S. PARDY: If I can add, so we have talked about a number of different factors here that lead to the differences, and one thing that we -- as we were preparing this interrogatory response is could we break out the individual components? And the conclusion we came to was we couldn't.

So, like, there is a number of different things that are leading it. The methodologies are so completely different. Like, we can't compare the individual components of each way we calculate it. We can come up with the difference in the answer, which we have already -- which you already have. So I am not sure what we are going to be able to provide other than a temperature difference between the two.

D. STEVENS: My understanding is what we are going to provide is the calculation that was used to determine design day for CDA for, I suppose, it is '24/'25 -- or, no, '23/'24. And also the calculation that was used for design day for the CDA for '24/'25.

As Mr. Pardy said, we are not necessarily going to be setting out, here is all the things that drove it, but rather just so that you can see we applied the calculation that was in place in the prior year. We applied the calculation that is in place in the current year.

I. RICHLER: So let's note that as JT-1.5.

UNDERTAKING JT-1.5: TO PROVIDE THE CALCULATION THAT WAS USED TO DETERMINE THE DESIGN DAY FOR THE CDA FOR 2023/2024 AND 2024/2025

I. RICHLER: And, Dwayne, we are almost at 11:00 when we were scheduled to take our morning break. So when it is convenient for you, let's pause. Okay?

D. QUINN: I have one more question, and then I think it will be an excellent time for a break. Thank you.

Mr. Stevens, I did go back, and I was trying to find information on the record to understand this change, and I couldn't find anything that spoke to the implications of the change from a design point of view, and, specifically, from a gas supply point of view. I am asking would Enbridge be able to provide what was on the record so the Board can see that there was implications provided in a way that -- in this case here, moved into the gas supply plan? I know that we didn't talk gas supply plan in this level in Phase I, but I would be -- I think it would serve the board if we saw what was on the docket in Phase I which spoke to the implications of this change from a gas supply perspective.

D. STEVENS: No, we are not prepared to do that. You look quizzical, but as I explained, this gas supply proceeding is not about revisiting demand forecast methodologies. It is not about investigating whether or not there was what other people might think is sufficient information on the record. The demand forecast methodologies are determined in rebasing applications. If there is questions about whether changes should be made, that is properly in scope for the next rebasing application.

By starting to answer these questions, we are admitting to relevance of things that, in my view, are entirely not in scope for this gas supply review. The framework is clear that the obligation is for the utility to apply the current OEB-approved demand forecast methodology, and that is what Enbridge has done.

D. QUINN: I risk deferring this break just -- does Enbridge not -- in my understanding -- let me do it this way: Let's go ahead with our break, Mr. Richler. I will come back to this issue. I don't think it will be the on specifics, but I need to understand Enbridge's understanding of the issues list and what the Board wants to do in this five-year gas supply review. And it may or may not be written in the original 2017 framework, but still, it doesn't mean it is not relevant to the Board's considerations, in my view. But let's take the break, Mr. Richler, and we will come back.

I. RICHLER: Thank you. We will take a break until 11:15.

--- Recess taken at 11:01 a.m.

--- Upon resuming at 11:15 a.m.

I. RICHLER: Welcome back, everyone. Dwayne, back to you.

D. QUINN: Thank you.

Mr. Stevens, I want to just recall our conversation from just before the break. My -- without the transcript, I can't and I won't put words in your mouth, but I was concerned that Enbridge has a narrow focus to this review.

I guess what I was wanting to do is come back to the issues list that says "Should the OEB review or amend the framework and/or annual review process including timing?"

And you and I have had many discussions, debates or whatever about the cost implications that come from gas supply, but as -- again, I don't want to put words in your mouths from the past, but costs -- Enbridge has been reluctant to provide cost implications from the gas supply plan. And we are wondering how does the Board see this, and how does the Board understand nearly $2 billion annually of costs, and when Enbridge creates a plan, what are the cost implications? So that is what I was relying on.

Can you help me with your perspective on the importance or the relevance of implications from a methodological change that impacts the gas supply plan, and when should the Board become aware of that and things be on the record so it knows what it is approving?

D. STEVENS: My specific objection to your questions, Dwayne, was that in my view and Enbridge Gas's view, the gas supply -- five-year gas supply plan is not an appropriate venue to revisit decisions about demand methodology that were made in the rebasing case.

And my concern is that by answering your question around providing what detail was on the record as to implications of the design day proposal in rebasing, if Enbridge is to answer that question and provide the materials that were on the record then, it necessarily leads to further questions about, well, was that sufficient? Should something be revisited? Are there problems with what was already agreed upon? And I don't think that is in scope for this gas supply plan, and so I don't want to start down that road, and so as a result, I, on behalf of Enbridge Gas, decline the question.

I assume that when parties engaged in their discussions around, well, what is the appropriate design day methodology in the context of the rebasing case, they did so with eyes wide open with a view to, well, what are the implications in general from changing or not changing the design day methodology. But that was done in a different case, and it is not something to be revisited here.

I recognize that there is overlap between various cases, but certainly from Enbridge Gas's perspective, and I hope from the OEB's perspective, the idea is to have separate proceedings that don't repeat what happened in prior proceedings.

D. QUINN: I accept -- and I am not going to try to parse out your answer. I accept some aspects of what you are conveying. But what you didn't touch on is should the framework or process be amended. And to the extent that there are parallel, sometimes conflicting proceedings that are going on for the gas utility, when should the Board be advised of cost implications for, in this case, the gas supply plan?

D. STEVENS: I entirely agree with you that there is an issue that is part of this case as to whether forward-looking changes should be made to the gas supply framework and related processes. Enbridge Gas has indicated -- I don't have the answer in front of me, but in response to at least one interrogatory, that its view is that, generally speaking, the process is working well. We expect that we might hear different from other parties through whatever written submission process follows after the technical conference.

We will certainly consider any submissions and suggestions that are made and provide our response, but I am not sure it is particularly helpful to talk about all of this in the abstract right now. I mean, the -- I expect that the witnesses would want to take away any suggestions for changes and consider those, and that is really something that is more in the nature of argument than it is evidence.

D. QUINN: Well, an assumption that was made in that is we are moving from this technical conference to written submissions. I didn't see that in the Procedural Order. Can you help me with that?

D. STEVENS: I mean, I don't know anything more than you do, Dwayne, about what the next steps are. The Board's typical process, unless something is urgent, is that it ultimately concludes processes through written submissions by parties. So I am expecting that is coming.

I mean, from Enbridge Gas's perspective, I suppose we will see whether there is a need for any more hearing process. Our hope is that the evidentiary record can be closed off through the technical conference and that we will proceed to written submissions, but I am sure the OEB will tell us their preference in due course.

D. QUINN: Okay. That is not for us to debate here. I just wanted to make sure that I was understanding the proceeding. But let's move forward. But to do so, I want to take one step back because we have it still up on the screen, and I don't want to have to come back to here.

But there was a -- but I focused on the design day demand for the CDA. This interrogatory speaks to the Enbridge Gas area. I differentiated the CDA from the EDA because the EDA didn't seem to change, or it only changed marginally, not significantly.

So as an additional undertaking, could you provide the same comparison/analysis from the 2023/2024 design day demand to the 2024/2025 design day demand for the EDA specifically.

D. STEVENS: And to be clear, are you speaking about the EGD EDA?

D. QUINN: Yes, thank you.

D. STEVENS: Yes, we can do that.

I. RICHLER: JT-1.6.

UNDERTAKING JT-1.6: TO PROVIDE THE COMPARISON/ANALYSIS FROM THE 2023/2024 DESIGN DAY DEMAND TO THE 2024/2025 DESIGN DAY DEMAND FOR THE EDA SPECIFICALLY

D. QUINN: Okay. I think the best place to move to would be if we could turn up FRPO-36, please. Okay. So in this interrogatory, we are seeking -- I am just going to scroll up myself here a little bit. Our preamble was talking about looking at -- oh, thank you, it is on the screen now, the -- how Enbridge can look to reduce risk for ratepayers moving forward with storage as it was agreed to in the Phase II proceeding.

I don't have the specific numbers, but there was a reduction in market-based storage. We encouraged the fixing of gas prior to the winter, and we thought we would discuss that in this proceeding.

So we asked to please provide Enbridge's views on mitigating price risk of load balancing by fixing the price of an amount of gas by assessing warm winters to mitigate the volume risk and carrying on from there.

Now, reading to the -- Enbridge's answer, it is sounding like it is premature, from Enbridge's perspective, for us to be asking these questions, which came as a surprise to us, and possibly the focus was on part C. So I am going to walk through this, and hopefully we will get some answers here. If not, we will have to find a different path to get those answers.

But we had asked in A, please provide Enbridge's view on dividing the amounts of gas over the key months from December to March once it is -- once you take into account the risks of warm winters and the amount that you would need to purchase in a warm winter. Is that essentially -- well, first off, how does Enbridge quantify the amount of winter gas that it is going to purchase to supplement storage based upon additional Dawn winter deliveries?

A. STIERS: Thanks, Dwayne. So just to try to be helpful, have you had an opportunity to review the response to STAFF-15? I wonder if we might go there.

D. QUINN: Well, again, if we can put a place holder on this page and go to STAFF-15, you can show me what you like to, please.

A. STIERS: Sure. So in STAFF-15, we lay out the criteria and provide the most recent proportional breakdown of our portfolio in terms of annual, seasonal, monthly and short-term purchases. And we go on in parts C through D to also discuss the proportions of indexed versus fixed purchases made.

D. QUINN: Can we scroll a little further, please. Okay. So starting there, how do you decide how much is fixed?

A. STIERS: Well, our preference -- as laid out within the response, our preference is always for indexed purchases to reduce exposure to market variability while achieving a fair market value, which is the underpinning goal.

Fixed purchases are made based on an operational need driven by changes in demand, weather variability and so on. And so those would largely be that bucket of short-term monthly purchases within the season that you saw above in parts A through B.

D. QUINN: Okay. Let's parse this out. You are going to be, based upon our understanding, reducing the amount of market-based storage going into this winter, correct?

A. STIERS: We have.

D. QUINN: Okay. You are going to purchase Dawn winter supplies, gas delivered at Dawn during the winter, to supplement the storage that you do have, then?

A. STIERS: There will be Dawn purchases, yes, through the winter.

D. QUINN: Okay. Do you do a scenario analysis to work out how much you should be purchasing at Dawn with varying levels of cold, as an example?

A. STIERS: Just a moment.

S. DANTZER: Our winter Dawn purchases are really in accordance with our gas supply plan. So the output of the optimization model determines the asset mix and our Dawn purchase requirement.

D. QUINN: So are there scenarios analyzed, average expected winter, colder than normal winter, warmer than normal winter? Do you do any scenario analysis?

S. DANTZER: Just one second. So our winter Dawn purchase requirement is, as I mentioned, an output of the gas supply plan optimization model which really is determined -- the starting point, anyway, is determined by the demand forecast incorporated in the plan.

D. QUINN: So same question, do you do any scenario analysis to look at -- nobody has got a perfect crystal ball on the weather. You are going with whatever you have got in your model. But things will vary. Do you do a scenario analysis?

S. DANTZER: Well, as part of the gas supply plan in the annual refresh we do. There is not a scenario analysis. Demand forecast is the starting point, and then, you know, the resulting supply activity that is required to meet those demands is -- falls out of that.

D. QUINN: Okay.

A. STIERS: And I would just add to that, Dwayne. So we start with that gas supply plan, and then from there, we are managing it week to week, month to month. We create monthly gas purchase plans, as you have probably read.

But from there, we also look at the variables that I mentioned in my earlier response which change week to week, and we adjust Dawn purchases accordingly. That gives us the flexibility we need to really narrow in and hit the demand as precisely as we can.

D. QUINN: Thank you for that answer, but I am going to break this down a little bit further. Table 2 is on the screen in front of us. First off, why don't you fix a higher percentage of your portfolio?

A. STIERS: Because our preference, as I said earlier, is for indexed price purchasing to -- I think we have a response, actually, that describes it exactly.

D. QUINN: Okay. Well, let me help you. So do you have a volume risk challenge in knowing how much gas you are going to need over the course of the winter?

A. STIERS: Can you define a "volume risk challenge" for me?

D. QUINN: You don't know precisely how much volume you are going to need, so you don't fix a hundred percent of an estimated volume.

Just to your point, you say you walk through it week after week seeing where you are.

A. STIERS: We have a plan for the entire winter. We have a portfolio. We create a purchase or commodity supply portfolio that is layered with all of the different contract types that are set out in table 1 of this response, annual, seasonal, monthly and short term. And then that portfolio in and of itself and the execution of it as planned over the course of the winter season and the whole year allows us to vary those purchases as needed.

D. QUINN: But you don't fix a hundred percent at the outset. You don't fix the price of your deliveries at the start of the winter.

A. STIERS: We do not fix purchases.

D. QUINN: Right. And I again --

A. STIERS: Sorry, can I just -- I will clarify what I just said. We don't fix a hundred percent, which was the premise that you just gave, of all of the contract types set out in table 1 at the beginning of the year.

D. QUINN: Okay.

A. STIERS: For sure.

D. QUINN: Maybe what we can do is -- I am trying to use as much as I can your responses that you are willing to give and expand upon those.

So table 2, can you by way of undertaking break that table out for only Dawn winter purchases, and then for '23/'24, if that is what you are using in this case here, what percentage you had fixed for Dawn winter purchases going into the winter, and then what your expectation for '25/'26 for winter Dawn purchases, what percent is fixed and what is on index.

A. STIERS: Sorry, what -- and so just to play this back to make sure I understand what you are asking for is you would like to know what amount of fixed purchases at Dawn are transacted or fixed in advance of the winter season. Is that right?

D. QUINN: Yes, as a percentage of Dawn winter deliveries in your gas supply plan.

A. STIERS: Sure. I think we could do that, but I can tell you I -- as we describe in this response and in others, we are not in a habit of fixing Dawn purchases of the nature that you are describing in advance of seasons. That happens within the winter season.

D. QUINN: And why don't you do that?

A. STIERS: Because, again, as described at the first bullet point within the response to part C and D, our focus is on index price purchases to reduce exposure to market variability and achieve a fair market value. And in our view, index purchasing allows to do that. We do not feel that fixed does, being so far in advance.

D. QUINN: Okay. Let's -- again, let's take the original undertaking if you have accepted that.

D. STEVENS: I am not sure it is going to be useful, Dwayne. I think the answer is -- the undertaking is going to say zero.

D. QUINN: Okay. Then let's do it this way, David.

D. STEVENS: I mean, perhaps we can say zero, subject to check.

D. QUINN: Okay. Fair enough. Okay. Let's try this, then. Focused on Dawn winter deliveries only, I would like Enbridge to provide by way of undertaking what is in your gas supply plan for '25/'26, what is -- what would your modelling suggest if the heating degree days are 10 percent colder than normal and 10 percent warmer than normal, and provide those -- that -- those determined values in an undertaking.

D. STEVENS: Sorry. To be clear, Dwayne, are you asking for what would be the Dawn purchase volumes if the winter was 10 percent colder than forecast and 10 percent warmer than forecast?

D. QUINN: Yes. And -- but I am also including what is in there currently. What we are trying to do, David, is produce a scenario analysis that would assist the Board to understand the amount of variability in expected consumption at Dawn, and as a result, how much gas would have to be purchased, delivered to Dawn, incremental or decremental to the gas supply plan.

D. STEVENS: So just to play that back, you are asking for the '25/'26 winter, what would be the impact on forecast Dawn purchases, or how would the forecast Dawn purchases -- winter purchases change if the assumption was that HDDs would be 10 percent more or 10 percent less?

D. QUINN: Yes. Including -- including the average. There is three outputs: What is in your gas supply plan, what is in your -- what would be 10 percent more HDDs and 10 percent less.

D. STEVENS: Okay. One moment, please. It looks like the witnesses need to confer.

A. MIKHAILA: Sorry, Mr. Quinn. Can I just ask a simpler way of maybe doing it, if you would be acceptable to it? Can we do it based on demand being 10 percent less than -- rather than HDDs being 10 percent less, or would you prefer the HDD?

D. QUINN: What I am concerned about is the heat-sensitive component. If you did 10 percent higher or 10 percent lower, you are assuming your contract customers are consuming 10 percent more, and they may not. They might only consume 1 percent more in a 10 percent colder winter. So I would like the heat-sensitive component of your demand to be what is varied.

A. MIKHAILA: Okay. Thank you. Just one more moment.

Thanks for that. We just had a moment to confer, and we understand that there is a factor that can be applied based on, you know, 10 percent change in HDDs and how that impacts demand of the general service market, and we will use that assumption to provide that.

D. QUINN: Thank you.

I. RICHLER: Let's note that as JT-1.7.

UNDERTAKING JT-1.7: TO ADVISE WHAT WOULD BE THE IMPACT ON FORECAST DAWN PURCHASES FOR THE 2025/2026 WINTER, OR HOW WOULD THE FORECAST DAWN WINTER PURCHASES CHANGE IF THE ASSUMPTION WAS THAT HDDS WOULD BE 10 PERCENT MORE OR 10 PERCENT LESS

I. RICHLER: And while I have the mic, I just need to note that I have to step out for a short period of time in a few minutes, and Catherine will be taking over as moderator.

D. QUINN: Thank you, Mr. Richler.

What I would like to do is go back to FRPO-36. I think we have exhausted the usefulness of the STAFF-15, though I appreciate you pointing it out to me.

So I wanted to, based upon what we just discussed, ask if I were to recommend or suggest that the minimum volume -- and whether it be 10 percent warmer than normal or whatever, you want to use as your base case -- is -- can you, from the warmest winter in the last whatever amount of time you can have, do that same calculation to figure out what the bear minimum of gas you will need at Dawn would be? Can you provide that?

I am going to let you choose a number because I don't want to say, okay, 27 years back. I think we went 30 years back in a previous case, but what I am looking for is the amount of cold that is the warmest weather that you have seen in the winter and calculate that amount of Dawn-delivered winter purchases that would be required to get you through the winter.

A. MIKHAILA: Are you looking for the -- maybe the minimum Dawn purchases -- winter Dawn purchases we have made? Like, is that the same thing?

D. QUINN: No. Because -- and I appreciate you clarifying, Ms. Mikhaila. I am looking at the '25/'26. I am looking at the weather for the last 20, 30 years, whatever. What is your warmest winter? And I used, just because it is a round number, 10 percent higher or 10 percent lower heating degree days. You might find that in 2012/2013, that you had 12 percent less heating degree days than what was in your gas supply plan. You use the 12 percent to say in 2025/2026, what would be the minimum amount that we would need to purchase at Dawn to get through the winter?

S. DANTZER: Is there a delivery area that you are referring to specifically? Because the temperatures will range.

D. QUINN: They will. But let's just say for the purposes of this scenario, just like it was the 10 percent, use a different number than 10 percent, but what is the minimum? I am just trying to ensure in the sensitivity analysis that we are doing that we don't limit ourselves to 10 percent because that is the number I threw out there when the real number is 12 percent or 17 percent. Who knows.

But your folks would know because you have got 30 years, at least, of data, and you can choose, if you want, over the last 30 years what was the warmest winter and what were the resulting heating degree days. Use that for the calculation of minimum purchases at Dawn to get through the winter. Can you do that?

A. MIKHAILA: Minimum purchases for the '25/'26 year using that same heating assumption?

D. QUINN: Yes. Yeah.

D. STEVENS: Yes. Enbridge Gas can provide an indicative view of the minimum amount of Dawn purchases that it would require for the '25/'26 year, assuming that weather was the warmest that could be reasonably expected.

I. RICHLER: JT-1.8.

UNDERTAKING JT-1.8: TO PROVIDE AN INDICATIVE VIEW OF THE MINIMUM AMOUNT OF DAWN PURCHASES THAT IT WOULD REQUIRE FOR THE 2025/2026 YEAR, ASSUMING THAT WEATHER WAS THE WARMEST THAT COULD BE REASONABLY EXPECTED

D. QUINN: I just have a couple more questions, Mr. Richler, and then I will be finished for today. Excuse me.

So if we start at the top of FRPO-36, you are going to end up with an amount that it would be minimum on a sensitivity basis to -- in the last 30 years. You want to divide that across the months of December to March, in my view. Would -- could Enbridge provide comment on whether that can be done, and if so -- well, first off, can it be done?

A. MIKHAILA: Yes, we can do that.

D. QUINN: Okay. So if you do that, what I would like to do is get your -- Enbridge's views on whether you could look at dividing the amount to be fixed in certain quantities, make it -- make it 25 percent, if you want, for each of the four intervals, and then fixing the price of that volume of gas delivered at Dawn 12, 9, 6 and 3 months ahead of the winter. Could that be done?

A. MIKHAILA: We can provide that as a basis of providing you what you are looking for, not necessarily our view.

D. QUINN: Well, I'm -- Ms. Mikhaila, I realize that you -- a scenario analysis, you could create anything, so thank you for answering forthrightly there. But why wouldn't Enbridge be able to do that?

A. MIKHAILA: We'll -- we can provide that.

D. STEVENS: Is the question why wouldn't Enbridge be able to do that, or why wouldn't Enbridge choose to do that?

D. QUINN: Okay. Let's deal with both of those.

Able to do that.

D. STEVENS: And I think Ms. -- I think Amy has said that it could feasibly be done.

D. QUINN: Okay.

D. STEVENS: But -- which is a different answer than would Enbridge choose to do that.

D. QUINN: Okay.

D. STEVENS: Because the question B in FRPO-36, I read, is provide Enbridge's views; in other words, would Enbridge choose to take this approach?

D. QUINN: Okay. Let's -- let's stick with able, and then we'll go to choose in a moment.

So on able, could you produce that for the scenario I created with the warmest winter in the last 30 years? That's -- if you are limited in your data, you can just tell us that, but what that would look like to break it up into three separate -- sorry, four separate tranches, three months apart, fixing the price of that gas, and what would that be.

A. MIKHAILA: Can I just have a moment, please?

D. QUINN: Sure.

A. MIKHAILA: Thank you for that moment. I just want to ask, are you looking for us to provide this as an undertaking?

D. QUINN: Yes.

A. MIKHAILA: Okay. And just a clarification on that. In both cases, I guess, A and B, the delivery would be across the months of December to March; although, in B, the purchases would be made 12, 9, 6, and 3 months in advance?

D. QUINN: It would be made -- the -- to use Mr. Stiers' language, you would transact for a fixed price for that delivered gas, but the gas deliveries would be spread across the December to March period.

D. STEVENS: And when you are asking what would this look like, Dwayne, can you just explain what you mean in terms of -- are you simply asking what's the volume that would be transacted 12 months ahead, 9 months ahead, 6 months ahead, and 3 months ahead, or what is it that you are expecting to see?

D. QUINN: The volume from the original undertaking and then what the price -- resulting price, fixed prices would be if Enbridge transacted in that manner.

D. STEVENS: And so when you say "what would the resulting fixed prices be", is that just based -- how are you presuming that Enbridge would get that information?

D. QUINN: Start -- well, how we get the information, what was transacted at Dawn for the month of December of -- in this case, December 2025, what was that price December 1st, 2024, February 1st, 2025, and subsequent in those tranches?

A. STIERS: And -- thanks, Dwayne.

So I guess the struggle I am having is just around -- and David is alluding to it as well -- the -- what is the nature of the pricing data itself, and is it readily available to us, and is it something that the current provider that we have for that would allow us to release for these purposes? All big questions for us around this, right.

D. QUINN: No, no. Actually, the -- let's -- Canadian Gas Price Reporter, can you --

A. STIERS: So GPR is --

D. QUINN: Yeah.

A. STIERS: -- is specifically what you would like?

D. QUINN: Well, I am choosing that to ask. Is there any restrictions on publishing what the Dawn price was December 1st for gas purchased December 1st the previous year; in this case, in 2024 for delivery in December 2025?

A. STIERS: Yeah, I understand the forward -- the forecast pricing that you have proposed, and if it is readily available, which I don't have a reason right now to think it wouldn't be, then we should be able to provide that for you from CGPR, yes.

D. QUINN: Okay. Great.

D. STEVENS: And to be clear, this is being done for the '24/'25 winter?

D. QUINN: No. The '25/'26 because I want to work with the same information as you currently have right now in front of you planning for this winter. But this is a retrospective, David, admittedly, what would have happened had you purchased the gas in the manner that I am laying out here, just so we have an understanding of what that would look like, and then we will know from there.

A. STIERS: Would it make more sense for it to be the prior year, though?

D. QUINN: No. No. I want to stick --

A. STIERS: That is what is at issue in this proceeding. I just --

D. QUINN: It is not at issue in terms of price. We are talking about methodology here, Mr. Stiers, and I --

A. STIERS: Then why would the year matter so much?

D. QUINN: The year matters because you -- all of our previous requests for undertaking were for the year of '25/'26, and I want to remain consistent as opposed to having a variable thrown in that, well, this winter was different. So I am just saying you have an average of what you'd expect for this winter, vary from that average, and show what it would look if you transacted prior for the deliveries of gas at Dawn through that period.

A. STIERS: So can I -- just one more clarification, then, to make sure we have got it. So it is for this coming winter season, and you want us to go back, but we can't do the three-month time frame, then, because that is October.

D. QUINN: No. It's September 1st --

A. STIERS: September, October --

D. QUINN: Okay. So October 1st, starting in December.

A. STIERS: -- November --

D. QUINN: December 1st. So you can go September 1st.

A. STIERS: Sure. We can do that.

D. QUINN: There you go.

A. STIERS: Yeah, I think we can do that.

D. STEVENS: So to be clear, Enbridge will provide a scenario where it sets out the minimum amount of winter purchases for '25/'26 being purchased in fixed price tranches at intervals that are 12, 9, 6, and 3 months ahead of the winter, and the fixed pricing will be indicated using CGPR or similar publicly available data.

I. RICHLER: JT-1.9.

UNDERTAKING JT-1.9: TO PROVIDE A SCENARIO WHERE IT SETS OUT THE MINIMUM AMOUNT OF WINTER PURCHASES FOR 2025/2026 BEING PURCHASED IN FIXED PRICE TRANCHES AT INTERVALS THAT ARE 12, 9, 6, AND 3 MONTHS AHEAD OF THE WINTER, AND INDICATE THE FIXED PRICING USING CGPR OR SIMILAR PUBLICLY AVAILABLE DATA

D. QUINN: And I was about to end on this matter. We are going to come back to C tomorrow. But, Mr. Stiers, I didn't want to be disrespectful in the -- in what you are saying, '24/'25, why are we using '25/'26? All of those scenarios I built before were based on '25/'26, so I wanted consistency.

But just for this last interrogatory so that we are not cherry-picking one year versus another, I would be happy if Enbridge wants to show what it would look like -- would have looked like for '24/'25 winter, so that same type of process for '24/'25.

A. STIERS: Yeah, I think we are okay with the undertaking that we have accepted. So we will consider that.

D. QUINN: Well, I think the Board would be interested in seeing -- we don't want to cherry-pick one year. To your point, I wasn't trying to cherry-pick a year. I was just trying to be consistent. But in thinking about it, I thought, okay, well, we have already experienced '24/'25, so why don't we do that also. Because it should be just math. But --

A. STIERS: But if that's the case, then...

D. STEVENS: It's going -- but then it will require another rerun minimum demand forecast, et cetera, et cetera. I think we can do one year, or we can do the other year, Dwayne.

D. QUINN: Well, Mr. Stevens, this -- and I am checking with the panel on this. It's a regression analysis also, is it not? To work out how much demand you have in your heat-sensitive component, to vary it by 10 percent, what was in your 2024 -- 2024/'25 model? What was 10 percent colder? What was 10 percent warmer? You have two outputs.

D. STEVENS: Now we are talking at entirely cross purposes, Dwayne. My -- the undertaking that we provided for '25/'26 is to use the amount that we determined in JT-1.8, which was the minimum -- an indicative view of the minimum amount of Dawn purchases that Enbridge could expect in '25/'26 based on the warmest weather experienced, and then take that amount and turn it into these fixed price purchases. Now you are introducing plus 10 percent, minus 10 percent, '23/'24, all sorts of variables.

D. QUINN: I know I got off script, Mr. Stevens. I will accept that. So what we did in JT-1.8, coldest winter in the last 30 years. It might be the same one, but what the prices would have looked like if you had done this same type of 12, 9, 6, and 3 forward transaction at Dawn.

D. STEVENS: Right. And that is what we have agreed to do for '25 --

D. QUINN: For '25/'26. But Mr. Stevens said, well, why don't we do '24/'25? And I am saying yes, because I think the Board would benefit from more than one year of data.

D. STEVENS: Again, I repeat what I said, Dwayne. We can do one, or we can do the other.

D. QUINN: There is not a -- there is not a huge amount of work, Mr. Stevens. This is just math. I can do it from my utility in a half an hour or less.

A. MIKHAILA: Can I ask a simplifying question?

D. QUINN: Sure.

A. MIKHAILA: If we were to do it for both years, provided the pricing information is available, can we use the same minimum purchases across both scenarios?

D. QUINN: Why don't we use that, because if it is the coldest in 30 years, the number should be the same. Yeah.

A. MIKHAILA: Similar -- I think it would be similar to --

D. QUINN: Yeah.

A. MIKHAILA: Thank you.

D. QUINN: Okay.

D. STEVENS: We are prepared to do it on the basis that we are not running two demand forecasts.

D. QUINN: So to --

D. STEVENS: So I think it is probably cleanest, Ian, to do this as a separate undertaking, that using the same demand forecast, indicate the fixed price contract amounts at 12, 9, 6, and 3-month intervals ahead of the winter for -- using the data relevant to the '24/'25 winter.

I. RICHLER: Okay. JT-1.10. Okay.

UNDERTAKING JT-1.10: TO INDICATE THE FIXED PRICE CONTRACT AMOUNTS AT 12, 9, 6, AND 3-MONTH INTERVALS AHEAD OF THE WINTER USING THE DATA RELEVANT TO THE 2024/2025 WINTER

D. QUINN: Thank you, Mr. Richler. Those are my questions for today. And thanks for the patience of the people standing by, and thank you, Enbridge, for your answers.

I. RICHLER: Thank you, Mr. Quinn.

Next up is Environmental Defence.

K. SIEMIATYCKI: Yes. Hello, everyone. This is Kate Siemiatycki, counsel for Environmental Defence. Can you all hear me?

I. RICHLER: Yes.

EXAMINATION BY K. SIEMIATYCKI:

K. SIEMIATYCKI: Okay. Hi. So my questions are going to be fairly brief. And I may ask for the Panel's indulgence because I may seek answers that are geared towards a lawyer who hasn't spent decades working in the energy industry and who may not have done that well in, you know, science class in high school, and that's why she went to law school. So, you know, forgive me if I sort of repeat some of my questions in an effort to fully clarify and understand the content of the application.

So if I could just -- I am going to first just ask a couple of brief questions about the source countries of the gas supply. And so if I could have us go to Exhibit I.1-CCC-12. Great. Is that the correct -- let me just see here. Page 2 of 3. Do you mind going onto page 2? Sorry. There we are. Yeah, there we go. Thank you.

So in the third bullet where it states:

"Natural gas supply purchases at Dawn as well as peaking supplies are assumed to be either Canadian origin or U.S. origin volumes that have already had any tariff costs applied upon import and delivery to Dawn/Ontario by shippers. As a result, Enbridge Gas has included these purchases as 'Canadian origin supply shipped through Canada'."[as read]

So I am trying to understand what that bullet means, and in particular, whether that means that there are purchases that are made at Dawn which may have come from the U.S. or that may have come from Canada through the U.S., which are then being included in the proportion, you know, in the table above assigned as "Canadian origin supply shipped through Canada". So that is sort of the first thing I just want to confirm or clarify.

A. STIERS: Sure. Adam Stiers again. I mean, to answer simply, I think we can say confirmed.

K. SIEMIATYCKI: Okay. Okay. And do you know -- are you able to say what proportion of that subset of the Canadian origin supply shipped through Canada are made up of this subset which are those that have either come from Canada via the U.S. or from the U.S., which are being included in that, I guess, 42.8 percent? I don't know if you know offhand or if you are able to take that away and then provide that information.

A. STIERS: So to start, and others may want to add in, but we've partially answered it to the best of our ability, actually, in combination between parts A and B.

The first comment I will make is just around the nature of the integrated natural gas system. It is impossible to track molecules with any precision across North America's natural gas systems. So to know with great accuracy where molecules in particular come from is not possible.

Now, that said, in the response to part B, we do comment and provide clarification that approximately 60 percent of suppliers at Dawn would be U.S. origin in nature, and so presumably would have a tariff applied, I think, in the scenario that you are describing. And, we presume, would fall within that category of, yeah, Canadian origin shipped -- sorry -- Canadian origin supply shipped through Canada, I believe, so the 42.8 that you referenced.

K. SIEMIATYCKI: Right. So -- so if I am understanding correctly, 60 percent of the purchases from Dawn are those that have already been paid tariffs, right, and some proportion of the 42 percent -- but that amount isn't specified, I don't believe, in the answer of the, you know, 42 whatever percent -- are those that come from Dawn; is that right?

A. STIERS: Sorry. Maybe you could restate it. You lost me there.

K. SIEMIATYCKI: Sorry. So another way of asking this is do we -- do we know the percentage of -- if you can go up to page 2 again. Sorry. I just want to see the exact right percentage amount. Do we know the proportion of the -- can you keep going up. Sorry. The proportion of the 42.8 percent that is made up of that portion that are those purchased at Dawn of which 60 percent are coming -- have already been --

A. MIKHAILA: I am following you. I am following you.

K. SIEMIATYCKI: Thank you. Thank you.

A. MIKHAILA: So the total purchases provided in table 1 come from table 10 of our original evidence, and, Ms. Monforton, you don't necessarily have to pull it up. But when I add up the Dawn purchases or sources of supply from table 10, it is 100,181 TJ of the 227,168 TJ.

K. SIEMIATYCKI: Are those that are purchased from Dawn --

A. MIKHAILA: Correct.

K. SIEMIATYCKI: -- and then 60 percent of the 100 are going to be those that fall into that category of, you know, they have already been tariffed, so they are being, you know, lumped into Canadian origin supply shipped through Canada; right? So roughly 60,000 TJ; is that fair?

A. MIKHAILA: Yes. But recognizing we don't procure the 60,000 TJ from the U.S. It is purchased in Canada.

K. SIEMIATYCKI: Yes, purchased in Canada.

A. MIKHAILA: But the supply origination, on a best-guess basis, that 60 percent is based on arrivals of gas at Dawn throughout an annual period.

K. SIEMIATYCKI: Right. Okay. Great. Great. That is very helpful. Thank you.

So then my next question is of that 60 percent, is there a way to calculate or do you know what proportion of that, let's say, 60 percent roughly is coming from a U.S. source as opposed to coming from Canadian sources, being transported through the U.S.? And if you don't know it, is there a way to, you know, guess it?

A. MIKHAILA: That step is a little bit more tricky because we don't necessarily know, for example, gas coming into Dawn on Vector, that might be supplied from Chicago, whether that original supply source is from Canada or from the U.S. So I don't think that is something that we can provide.

The 60 percent is just arrivals to Dawn, Canadian versus U.S. arrivals of gas at Dawn. But where the U.S. gas originates, whether some of that could be from Canada, is not something we have the ability to provide.

K. SIEMIATYCKI: And, again, as someone who hasn't been working in this sector for decades, when Enbridge contracts to purchase a supply that is coming, let's say, from Chicago or, you know, somewhere in the United States, what information is provided about the source of that gas?

A. STIERS: We typically do not receive information regarding the national origin of commodity purchased in those scenarios.

K. SIEMIATYCKI: Do you request it, and it is not provided, or you don't request it?

A. STIERS: It is not requested.

K. SIEMIATYCKI: Okay. Okay. Okay. Thank you.

So now if we could go to Exhibit I.2-ED-8, please. So if you go down, I think, to the -- yeah, to that table. Perfect. So in terms of the amounts and related percentages that have been supplied in this table of gas coming from, you know -- the source being the U.S. versus Alberta, again, as somebody who may have had to Google "regression analysis" not that long ago as a reminder to myself, you know, when I look at 52 percent coming from U.S. and 21 percent coming from Alberta, I don't think those add up to 100. So could you explain to me, where -- what is the missing percentages in this table? What am I missing here, which I am sure is a completely easy-to-answer question, I imagine?

A. MIKHAILA: The difference is just what we have just discussed, which is Dawn purchases, which --

K. SIEMIATYCKI: Oh, I see.

A. MIKHAILA: -- are not necessarily U.S. or Alberta as requested, and as well, peaking supply.

K. SIEMIATYCKI: Okay. That's all? It's just the Dawn purchases that are --

A. MIKHAILA: Yeah, and the peaking --

K. SIEMIATYCKI: -- omitted from here?

A. MIKHAILA: -- the small amount of peaking, yeah.

K. SIEMIATYCKI: Okay. Great. Thank you.

Okay. So now I just have a couple of questions about the demand forecasting. And so if we could go to I.2-ED-4. Yes. Okay. So this was a question about the -- trying to understand whether -- to what extent there's any differences in the demand forecasts for gas supply as in the asset management planning. And the first line of the answer states that design day demand forecast used in 2025 to 2034 asset management plan and the submitted five-year gas supply plan are consistent.

So I guess my questions are what does "consistent" mean, and does it mean the same, or does it mean something different than the same? And if it does, what is that?

G. BASHUALDO-HILARIO: It means the same.

K. SIEMIATYCKI: It means the same. Okay.

And are you able to provide -- I mean, I imagine it was provided in a different proceeding, but are you able to provide, then, the demand forecast tables from the asset management plan just to confirm that?

D. STEVENS: Just one moment, please.

K. SIEMIATYCKI: Thanks.

D. STEVENS: We are just asking ourselves here over at the counsel table whether the AMP includes demand forecast tables, and it's not our recollection. I don't know. Do you have a different recollection, Gilmer or Steve?

S. PARDY: Sorry. I missed that, Mr. Stevens.

D. STEVENS: Do you recall, does the AMP include demand forecast tables? That's not my recollection.

S. PARDY: I am not sure about that either.

D. STEVENS: To the extent, Kate, that there is a demand forecast set out in the 2025 asset management plan, we can provide a reference to that. But, again, I am not sure whether there is such a thing.

K. SIEMIATYCKI: Sure. I mean, if it does exist, a reference would be helpful. I guess if it doesn't, then, I mean, whatever led to the answer that it is the same, I imagine that that would have involved some cross reference, so whatever was cross-referenced to -- you know, to make sure that it is the same or to answer the interrogatory, if that could be provided, then, you know, in the event that it wasn't included in the previous AMP.

S. PARDY: I was going to say I think when we say they're the same -- and I would have to look specifically in this case. There is always the issue of timing as to when this forecast was prepared versus the other. But if I am looking at where I am sitting at today, like, if this year we only prepare one design day demand forecast, that would be used for asset management, and it would also be used for gas supply. So I think when we say it is the same, that is what we are referencing.

Now, when you look at specific -- an asset management plan versus a gas supply plan, there is always the issue of the timing of when it was prepared based on what forecast.

K. SIEMIATYCKI: So -- so I guess I am just asking for whatever -- you know, regardless of whatever assumptions or whatever year for the 2025 to 2034 asset management plan, you know, what the forecast was, you know, what those base forecast numbers were, that is what would be helpful to review.

D. STEVENS: But I think what we are saying, Kate, is that any time we are looking at the precise same preparation date for a gas supply plan and an AMP, then it will be the same design day forecast. If they happen to be three or four months off, then we may have year one's forecast in one of these documents and year two's forecast in the other document. But in any given year, there is only one forecast.

K. SIEMIATYCKI: Right. Okay. Okay. Well, then I guess what I would ask for is the reference, if there is one, within the AMP to any design day forecast that underpinned that planning. And then in the event that what that reference tells me is that there may be some differences, I guess, you know, I may be asking for further information at that point.

D. STEVENS: Certainly. We can undertake to provide or to point you to -- because I believe the AMP will be on the record -- well, I know it is on the record in other proceedings. We will provide a reference to any design demand forecast that is set out within the AMP evidence that underpins the plan.

K. SIEMIATYCKI: Yeah, thank you.

C. NGUYEN: That is JT-1.11.

UNDERTAKING JT-1.11: TO PROVIDE THE REFERENCE WITHIN THE AMP TO ANY DESIGN DAY DEMAND FORECAST THAT UNDERPINS THE PLAN

K. SIEMIATYCKI: And then my last question is -- if we can go to I.2-ED-5. So I am looking at in the response towards the end of A. It says:

"On an annual basis, the decline in average use is outpacing the rate of customer growth. On design day, the rate of customer growth is outpacing the design in design day demand."[as read]

Can you explain this to me in lay terms what that means?

I thought this would be the easiest question to answer.

S. PARDY: Sorry. Mr. Gilmer and I were just discussing because the average use is his forecast and the design day is my forecast, so it -- so, like, basically what we are saying, so the rate of customer growth is outpacing the decline in design day demand, so customer growth is increasing more than any decrease that we see in design day demand. And that is different on the annual use, which the annual use is declining more than the design day is growing. So there is two different things happening at the same time. One is outpacing the other.

K. SIEMIATYCKI: Okay. Okay. Okay. That is helpful. Thank you. Okay. Those were all of my questions.

C. NGUYEN: Okay. Up next, CCC.

EXAMINATION BY L. GLUCK:

L. GLUCK: Good afternoon. My name is Lawrie Gluck, and I am a consultant for the Consumers Council of Canada. The questions I have for the witness panel today are seeking to get a better understanding of the cost effectiveness analysis that is provided in appendix I to the application and was updated in Exhibit I to CCC-9 at attachment 1.

To that, I would like to compare the information provided in CCC-9 relative to the information provided in FRPO-37, attachment 1 with respect to Vector contracting. If we can start by going to CCC-9 at attachment 1, that would be helpful.

So my understanding of this table -- and I am going to be using the Vector analysis as the example sort of representative of the cost effectiveness analysis, and I am looking at the Vector contracting decision for the 2022 to 2023 gas year. So this would be line 32 at column D. And here what I am seeing is that Enbridge forecasted 10 cent per VJ premium to be paid for Vector supply. Is that a correct understanding of what this table is showing?

A. STIERS: Yes.

L. GLUCK: Okay. Thank you. If we could go to FRPO-37, attachment 1, page 2, please. And my understanding of this table is that it is also showing the actual cost differential -- sorry, sorry, I went ahead of myself. Can we go back to CCC-9 for a second?

So if we go to -- if we look at line 29 now, my understanding of line 29 is that that is the actual - for the 2022 to 2023 gas year, that is the actual discount that was paid for Vector supply relevant to Dawn, so it was a 26 cent per GJ discount. Is that right?

A. STIERS: Yes. And to maybe be helpful, this is -- this version, appendix I, is all Vector contracts.

L. GLUCK: Okay.

A. STIERS: Whereas FRPO-37, attachment 1, I believe, is only the two 20,000 per day contracts.

L. GLUCK: Okay. That is helpful. So if we can go to FRPO-37, I think what you are saying is going to explain the difference. When I look at this, it is showing on an actual basis, for the 2022 to 2023 gas year, it looks like a $1.52 million premium that was paid for Vector supply. And that is the correct understanding of this table?

A. STIERS: It is. Because that is the premium associated solely with two of the Vector contracts that were each for 20,000 decatherms per day.

L. GLUCK: Okay. So underpinning looking at CCC -- thinking about CCC-9 -- I don't know that we have to pull it up. Underpinning that discount that we were looking at of, you know, 26 cents per GJ, there is actually -- we know there is -- well, I know there are more contracts. There are more Vector contracts that are underpinning that number. Is that right?

A. STIERS: Yes, that is correct.

L. GLUCK: Okay. And can you explain those other contracts, what would be -- in terms of FRPO-37, what would be the line items that are sort of different? Is it the tolls? Because I would expect that the supply cost would be the same. Is that fair?

A. STIERS: Just give me a moment here. So whereas appendix I contains all four of our Chicago to St. Clair to Dawn contracts for 185,000 decatherms a day, as I just said, FRPO-37 only includes 40,000 decatherms a day on two contracts. Okay?

Aside from that, they are similar. Both accounting for certain AMA revenue and associated release values for those pipes. And I would say what I would take away from either of these is that FRPO-37 is really only a partial picture whereas the discounts set out in appendix I show the more holistic view of the discount relevant to Dawn for the aggregated Vector capacity.

L. GLUCK: And when you say it is a more comprehensive picture, is the point that you are making about there being more contracts underpinning it, or is there something else that is different? Maybe I should put it this way: If you were to take all of your contracts, all your Vector contracts and do the FRPO-37 analysis for the 2022 to 2023 gas year, would you get to the 26 cent discount on an actual basis? If you were to run that analysis, would it match that?

A. STIERS: If we were to -- so there wouldn't be any change per se. I guess -- are you asking is there a difference in the methodologies?

L. GLUCK: I think that -- yeah, I am asking whether there is something different between what is shown underpinning CCC-9 versus what is shown here in FRPO-37.

A. STIERS: I can -- maybe it would be helpful to clarify that within appendix I, not all of the AMA-related revenue or no-fill related cost avoidance and release values are actually included in comparison to FRPO-37. So in other words, the discount would become greater if we were to approach it in the same manner as FRPO-37.

L. GLUCK: That is the one difference? Is that right?

A. STIERS: Yeah.

L. GLUCK: Okay. I don't want to create a ton of work. Would it be possible just for the -- you have information year to date. So I think that is -- if you go down two pages here in attachment 1, I think you have year-to-date information 2024, 2025. If you could do this analysis for all the Vector contracts just for that one gas year.

A. STIERS: So just to confirm, you would like all Vector contract detail included in the current schedule on the screen, so November '24 to -- how far forward? Current day, you said? How many months?

L. GLUCK: What I am going to be comparing it to is CCC-9, which I understand -- I am just going to pull that back up.

A. STIERS: I think it -- it may be the end of July, but whatever it is to CCC-9, yes, we can take it to that point.

L. GLUCK: Okay. That would be great. Thank you.

C. NGUYEN: JT-1.12.

UNDERTAKING JT-1.12: TO PROVIDE ALL VECTOR CONTRACT DETAIL INCLUDED IN THE SCHEDULE AT FRPO-37, ATTACHMENT 1, FROM NOVEMBER 2024 TO CCC-9

L. GLUCK: Okay. Thank you very much. Those are my questions.

C. NGUYEN: Okay. Thanks. Up next we have GFN.

EXAMINATION BY N. DAUBE:

N. DAUBE: Lawrie, you were quick. Hi, everyone. I am Nick Daube. I am on for Ginoogaming First Nation.

My first set of questions for the Panel relates to GFN-2, and then I will be spending some time on GFN-3, and I think that is it for today.

At GFN-2, question A, in response to the general question of what Enbridge's position is for how the gas supply plan impacts or doesn't impact traditional lands or Aboriginal and treaty rights, Enbridge states in response A that:

"The gas supply plan focuses on the movement of the gas molecules using existing facilities."[as read]

A few things I am wondering if Enbridge acknowledges -- does Enbridge acknowledge that the plan also affects where the company sources its gas?

A. MIKHAILA: Yes. The gas supply plan is planned around the sources of supply.

N. DAUBE: Do you as a result of that acknowledge that the plan also has an impact on which areas of your existing network will experience greater or less use?

D. STEVENS: Sorry, what do you mean by that, Nick? When you say "which areas of your network", are you talking about the distribution network?

N. DAUBE: Right, existing pipelines --

D. STEVENS: But are you talking about Enbridge Gas Inc.'s distribution network? I am just distinguishing that from sort of upstream transmission pipes that are bringing in the gas to Ontario, which aren't Enbridge Gas pipes.

N. DAUBE: Well, I am trying to understand the answer in A, which seems pretty limited in what it is acknowledging. It says:

"The gas supply plan focuses on the movement of the gas molecules using existing facilities."[as read]

So if the Panel has already acknowledged that it also affects where the gas is sourced, presumably that as a consequence also means that the gas is flowing in different parts of the system, different ways, different sources coming from different places would have an impact on all of that. Or no?

D. STEVENS: Again, I am sure the witnesses can speak to this, but I think predominantly, this speaks to what adds are being used to bring the gas to Ontario, not what happens when it gets to Ontario. Regardless of the gas supply plan, a customer in Oakville needs whatever supply they need on peak day.

N. DAUBE: Okay. Well --

D. STEVENS: So the Enbridge pipes to get the gas to Oakville will be used the same whether the gas came from Pennsylvania or Alberta.

N. DAUBE: Right. I guess what I am asking is if you are sourcing from, say, northern parts of the network versus southern parts of the network or elsewhere, doesn't that mean that carrying through the network, there will be different flows?

D. STEVENS: And, again, I think if you look at the map of transmission pipes, it -- the distribution network is used the same either way. It is the upstream network to get the gas into the delivery areas that changes.

N. DAUBE: Okay.

D. STEVENS: I should let the witnesses speak --

N. DAUBE: Yeah, I would agree.

D. STEVENS: -- I am just trying to move things along.

N. DAUBE: Thank you, David.

A. MIKHAILA: I agree with what David just said. Many of the sources of supply and the transportation pipelines that are used to get that supply to Ontario are not Enbridge Gas pipelines.

So, for example, if the supply is coming from Empress, it will be transported on TransCanada to our system, our distribution system. And if it is coming elsewhere, like the Appalachian Basin, it will be transported on a pipeline like Nexus to Dawn. And our distribution system is not necessarily impacted by that upstream supply source.

N. DAUBE: Well, this is -- so digging in I am interested once it is in Ontario. Am I misunderstanding, wouldn't it be the case that if the original source is Empress and TransCanada versus Nexus to Dawn, that has an impact on, you know, where gas is flowing once it is in Ontario and the types of flows that you see, again, once in Ontario?

A. MIKHAILA: Once it is in Ontario --

N. DAUBE: Versus a scenario, for example -- sorry. I phrased it poorly. Versus a scenario where it is purely coming from one source or another or some other scenario of balance.

A. MIKHAILA: Once it is in Ontario from the third-party pipeline, there could be the use of our Dawn Parkway system to move it from our interconnection with TransCanada to storage at Dawn. Otherwise, if it is coming from, you know, a U.S.-based source, it will generally land at Dawn or -- but I think maybe that is one use of an Enbridge Gas asset for a supply source difference between where it is sourced from.

N. DAUBE: And, presumably, if you were sourcing a hundred percent from one of these sources, that would impact the need for other assets on your system. Is that right?

A. MIKHAILA: I am not sure what you are referring to, sorry.

N. DAUBE: If you were sourcing 100 percent from Empress TransCanada, wouldn't that mean that assets that you use in closer proximity to Nexus and Dawn, when you are sourcing from that location, wouldn't that mean there is less need for those assets? I know that is not what you are proposing, but wouldn't that be the case if you are sourcing a hundred percent from Empress and TransCanada?

A. MIKHAILA: Sorry. Less need for what assets?

N. DAUBE: Well, you tell me. Pipelines that you are currently using in relation to Nexus and Dawn.

A. MIKHAILA: Just give us a moment, please.

D. STEVENS: But to be clear, Nick, you are asking about Enbridge Gas Inc. assets?

N. DAUBE: Yeah.

A. MIKHAILA: Just using your example, if we were to, say, source a hundred percent of our supply from Empress, then it could have an impact on our design of the Dawn Parkway system. I think -- is that what you are trying to get at?

N. DAUBE: Yeah.

A. MIKHAILA: It could. I don't know. We haven't run that scenario. But it would also significantly impact the diversity of our supply arrangement. It is not something we would be looking to do.

N. DAUBE: Yeah, that is fair. And all sorts of different scenarios when you run the range between those two extremes more than they could, it stands to reason that they would have an impact on your need for assets that you currently have in place. Isn't that right?

A. MIKHAILA: I would say limited to the Dawn to Parkway -- like, our transmission systems. Our distribution systems would not be impacted by the supply source.

N. DAUBE: Distribution, no. And the first you said was which?

A. MIKHAILA: Transmission.

N. DAUBE: Okay. What sorts of impacts would it have on transmission? And I understand these scenarios might make no sense from diversity perspectives, reliability perspectives. I am just trying to understand what the impacts would be.

A. MIKHAILA: I can't speak to those impacts because we haven't assessed those scenarios.

N. DAUBE: Okay. A related consideration in these extreme scenarios or scenarios leading up to those extreme scenarios, I guess, wouldn't there be a similar impact on the kind of maintenance activities that you need to perform on system assets?

A. MIKHAILA: I can't speak to the maintenance activities of our assets.

N. DAUBE: Can anyone on the panel?

D. STEVENS: Is your question, Nick, assuming all the gas came from Empress, and assuming that somehow meant less, not more, Dawn Parkway capacity, then there would be less Dawn Parkway maintenance requirement?

N. DAUBE: Yeah. All of this takes place in the context of response A --

D. STEVENS: I wonder if this actually goes a different direction than you are expecting. If all the gas is coming in from Alberta, there is actually a need for more, not less Enbridge transmission capacity. Because there is more gas flowing from Parkway to Dawn.

N. DAUBE: Yeah. That may be. Which would be an impact.

D. STEVENS: Right. But an increasing impact.

N. DAUBE: Sure. It would produce -- thank you for that. And would produce presumably similar impacts when it comes to related maintenance that is required as a result of that increase or decrease -- increase in this scenario, decrease for infrastructure. Is that right?

D. QUINN: Nick, this is Dwayne Quinn. I want to give the witness panel, if I may, Mr. Stevens, the opportunity to either confirm or evolve --

N. DAUBE: Dwayne, I appreciate the intervention, but that is actually the most helpful answer that I have gotten so far, so I would like to run with Dave for a little while longer, and then we can see if the panel agrees.

D. QUINN: Sorry, Nick, I was just trying to make sure the record was clear. I will leave it at that.

N. DAUBE: Yeah. Thank you. I appreciate it, Dwayne.

D. STEVENS: I don't -- I mean, Steve Pardy, do you have any comment on whether, you know, change in the utilization of a transmission facility changes the associated maintenance costs?

S. PARDY: I think that is --

N. DAUBE: I am sorry. So what we have heard -- that wasn't the question. What we have heard from David is that -- and which I would like the panel to agree with or disagree with, was if you were sourcing, for example, a hundred percent from Alberta, from Empress, there would be an increased need for certain infrastructure. So why don't we stop there and just see whether you agree with those statements.

S. PARDY: And I guess this is a very hypothetical situation.

N. DAUBE: Oh, yeah, yeah. Listen, I don't need to debate into whether this would ever happen or whether it would make sense from other perspectives.

S. PARDY: Well, I am trying to envision if it happened. The Dawn Parkway system was originally designed to flow in the direction you are talking, so it has evolved over the years with different contracts and different projects. And would -- if we changed everything, would things be different? Probably.

A. MIKHAILA: I think I --

S. PARDY: Sorry. I was going to say if it led to projects, we would have to bring those projects to the Ontario Energy Board for leave to construct applications, so the impacts of those, and the impact of our decisions that affected that we would -- that would be taken into consideration.

From a maintenance perspective, it could be more, it could be less, it could be different maintenance that we are doing. So it is not necessarily one way or the other.

N. DAUBE: But it would almost certainly be different in any case, right?

S. PARDY: Different in what sense?

N. DAUBE: From the status quo.

S. PARDY: We would still have to inspect our pipelines, we would still have to operate our valves, we would still have to do annual maintenance. Like, those sorts of things wouldn't go away just because gas is flowing differently or flowing less.

N. DAUBE: Yeah, maybe I am not phrasing it right, but that is not quite the question. I am just saying the type of maintenance that you would need almost certainly would be, even in details, different if the infrastructure is getting heavier use, if there is more infrastructure, if there is less infrastructure that is needed as a result of the gas plan. The frequency of the maintenance, where the maintenance is most needed, all of those things in the details would presumably be different.

S. PARDY: I am not sure. Like, some stuff may be. But like I said, there is a lot of maintenance that we do in our system. It is required by the fact that we are using the system, not necessarily driven by how much gas is flowing on an individual day. So if we have to do annual valve maintenance, we have to do annual valve maintenance whether it flowed one molecule or 500 molecules. So that is the part I am struggling with. And it is a very -- it is so hypothetical, like, I can't -- you are asking me to give a specific response to a hypothetical question, and that is what I am struggling with.

N. DAUBE: Sure. But, you know, accepting the hypothetical, a hundred percent sourced from Alberta, are you saying that maintenance activities down to their every detail, who is showing up in what location for what purpose over the course of -- over the course of a year is going to be exactly the same as under the status quo gas supply plan? I assume the answer is absolutely not. With different types of use, different infrastructure in place, we can't say exactly how the maintenance activities will change, but for sure they would change in some respect. Is that incorrect?

S. PARDY: I think my answer is I don't know.

N. DAUBE: Okay. So when you say -- when the company says "Hence the gas supply plan does not have any impact on traditional lands or Aboriginal treaty rights", maybe I suggest to you that how it should be phrased is we don't know whether the gas supply plan has any impact on traditional lands or on Aboriginal and treaty rights. Is that correct?

D. STEVENS: It sounds an awful lot like argument to me, Nick. I mean, I think you have Enbridge's position. You have put forward a stark hypothetical, and there is no clear answers to that hypothetical. I am not sure how that changes Enbridge's view. It may change your argument, but I don't know where Enbridge's view changes based on all this.

N. DAUBE: Yeah. David, I don't think the problem is the questions here. I think the questions have been fairly straightforward. And at this point, you have given more evidence than the panel. So, respectfully, I would ask that, you know, let the panel either confirm the statement they have already given or qualify it, and that you let them do it without coaching. So if you are unwilling to do that, that is fine, but I think --

D. STEVENS: That is fine, Nick. Please go ahead, witnesses.

L. WHITWHAM: Good afternoon, Nick. Lauren Whitwham.

So the question that we are looking at, the gas supply plan itself in its detail does not have an impact on traditional lands. However, as you were alluding to, the maintenance, any projects that come off of that, they do have impacts on traditional lands in which we have consultation programs in place for leave to construct as well as engagement for maintenance activities for Nations in close proximity. Does that help?

N. DAUBE: Okay. Somewhat. Thank you.

Can we go to D, please. This should be fairly brief. Enbridge says:

"Should an Indigenous group express an interest in being engaged on the gas supply plan, Enbridge Gas will consider ways to do so on a go-forward basis outside of the regulatory process."[as read]

So I am happy to take this as an undertaking or however the company would prefer. So Ginoogaming is interested, and what it would like is a commitment for Enbridge Gas to discuss this, the mechanics of it, at the Indigenous Working Group.

L. WHITWHAM: When you say "mechanics of it", do you mean the mechanics of the plan?

N. DAUBE: So exactly -- I guess what I am getting at is should -- the statement at the moment is should an Indigenous group express an interest in being engaged on the gas supply plan on a go-forward basis, so Ginoogaming is expressing that interest. And when I say "mechanics", I mean how is that going to happen for the next round would be discussed at the Indigenous Working Group.

A. MIKHAILA: I think we have also agreed to provide the Indigenous Working Group with a presentation on the gas supply plan as something in our response to GFN-1D, part D. So I think that can probably be coordinated.

N. DAUBE: Okay. Thank you.

On E and F, I am not quibbling with the answer except I think that the way the questions are phrased yield yes/no answers, and I am not sure whether Enbridge is agreeing with the two questions or not. So I wonder if it is possible just to clarify whether Enbridge is saying yes or no to E, which is:

"Does EGI agree that a requirement to engage with impacted First Nations on significant developments such as the energy transition would help to ensure that the concerns and perspectives of EGI's First Nations customers are identified?"[as read]

So in its answer, is Enbridge trying to say yes, and here is the explanation? Or is it trying to say no, and here is the explanation? Or something else?

L. WHITWHAM: I would go with we are saying yes, and that is why we are engaging with Indigenous groups and the IWG on energy transition currently.

N. DAUBE: Okay. And does the same go for F?

L. WHITWHAM: Yes.

N. DAUBE: Thank you.

Okay. Going to GFN-3 and your answer to A. The question asked what criteria Enbridge used to determine the subjects it would address in section 6 of the GSP, which is achieving public policy. Enbridge listed two OEB decisions in guidance documents.

And so my question is this: Does Enbridge Gas say there is anything in those documents that would preclude the consideration of how the gas supply plan affects First Nations as part of the public policy section?

S. DANTZER: Steve Dantzer here. No, there is nothing that precludes that.

N. DAUBE: Okay. Can we go to C, please. And Enbridge says it is not -- this is the second sentence:

"It is not clear that reconciliation is a public policy that directly applies to gas supply plans."[as read]

So two questions up front. The first is, is it fair to say that consulting with First Nations, and whether that is at the Indigenous Working Group or elsewhere, would likely assist Enbridge in assessing the potential impact its gas supply plan has for reconciliation or its impact on First Nations?

L. WHITWHAM: Can you repeat that, please?

N. DAUBE: Yeah. And being fair to the previous answer, it may be that you are agreeing with it, and you are saying, yes, we are already doing that. So the question is, is it fair to say that consulting with First Nations, in general -- and this can be at the IWG. It can be elsewhere. Is it fair to say that consulting with First Nations would assist Enbridge in assessing the potential impact of its gas supply plan on First Nations, on reconciliation?

L. WHITWHAM: Thank you. So the word -- so we would say that we would be happy to engage to assist in learning about the impacts of the gas supply plan on First Nations. Yeah. We would be happy to engage to learn of the impacts through the IWG or through other means.

N. DAUBE: I guess what I am -- at the risk of asking an open-ended question, I guess what I am struggling with here is can you give me -- I don't understand how Enbridge can talk about the impacts of the gas supply plan on First Nations if there is no evidence in the plan of consultations with First Nations that present the plan to them and ask them, how does this affect you?

So that's -- I think that's as plain language as I can get with it, although I am happy to try again. How is it that Enbridge can talk about the impacts or lack of impacts on First Nations if there is no evidence of consultation with them for the purposes of this plan?

A. STIERS: Hi, again, Mr. Daube. Thank you. So I think maybe to clarify things to your points and reiterate what has already been stated slightly differently is the company is committed to engagement through the Indigenous Working Group, and you heard us commit to meeting with First Nations to better understand things like impacts.

I don't think that the gas supply plan, as it is currently presented, necessarily has a dedicated section, and I think that is the point you are making. However, it is not clear to us at this time that it should. I think what we are committing to at this point is the engagement in principle and helping to understand and support a dialogue going forward regarding gas supply plan and its potential impacts. I think that is about as far as we are willing to go.

N. DAUBE: Okay. At D -- the answer to D, that is, the company says that Enbridge Gas does not always explicitly reference reconciliation, but this doesn't mean the company isn't guided by the Indigenous reconciliation action plan. Does that statement apply for the purposes of the gas supply plan as well and not just the company's actions in a general sense?

L. WHITWHAM: And I apologize if I misunderstand your question, but -- so the gas supply plan did not reference reconciliation, but that does not mean that Enbridge in our -- in our commitments is not -- we recognize reconciliation. We have the IRAP, the Indigenous reconciliation action policy. That's out there to advance commitments that we made, that IRAP sets out our commitments towards reconciliation. And just because we don't reference it in the gas supply plan doesn't mean that Enbridge isn't committed towards the goals that are laid out in the IRAP.

N. DAUBE: Yeah, I am just trying to put it in a positive way. Are you -- so it doesn't necessarily mean -- I think there are some double negatives or straying pretty close to double negatives here at the moment.

What I am trying to determine is whether Enbridge is saying that the gas supply plan is influenced in some -- in some way, shape by the Indigenous reconciliation action plan.

L. WHITWHAM: The -- the purpose of the -- the gas supply plan was not influenced by the IRAP. The IRAP, the Indigenous reconciliation action, can be applied to aspects of the business, but it is actually a layout of the commitments that Enbridge is working towards. So if some of the aspects of different plans help to support the commitments within the IRAP, that is great, but the IRAP doesn't necessarily apply to all of the plans that we -- that Enbridge Gas puts forward.

N. DAUBE: Okay. I think the answer to most of these is they aren't there, but I want to give you the opportunity to disagree with me. I don't think there is any section in the gas supply plan that addresses matters of specific concern to First Nations. Do you disagree with that?

A. MIKHAILA: Sorry. Was the question were there any sections of the gas supply plan that address the concerns?

N. DAUBE: Let me ask it in a different order. I count one reference to "Indigenous", and it is in the context -- it is on page 17 of the report, and it comes in the context of stakeholder feedback. It will be 20 on the PDF. Maybe I am on a different version.

D. STEVENS: Is your question, Nick, whether the gas supply plan sets out what Enbridge understands to be concerns or issues of Indigenous groups and then responds to them?

N. DAUBE: No. So my question is -- you can just -- this isn't a material part of the question. I think there is only one reference to "Indigenous" or use of the word "Indigenous" in the plan, and it comes in a general description of stakeholder feedback. There is only one reference to "First Nations", and it comes in a description of 20 First Nations as customers.

So the original question with that context, which is the main question, is can you take me, please -- can you refer me to any section in the plan that Enbridge says addresses matters of specific concern to First Nations?

A. MIKHAILA: There are no specific sections.

N. DAUBE: And is there any section you can point me to where the company says it has specifically been guided by the Indigenous reconciliation action plan?

A. MIKHAILA: There are no specific sections that state that either.

N. DAUBE: Okay. These are my final couple of questions. Am I right to assume that to the extent that non-commercial considerations, including ethical considerations or goals relating to reconciliation, form part of a gas supply decision, we would see those non-commercial considerations referenced in your gas supply plan in your application?

D. STEVENS: What do you mean by an ethical concern, Nick?

N. DAUBE: Well, anything public policy related -- well, David, again, I don't think this is --

D. STEVENS: I think it is entirely appropriate for us to understand your questions, Nick. You don't need to berate me for trying to understand what you are asking.

N. DAUBE: Well, David, I wouldn't call it "berating". I would call it checking to see if the panel understands the questions. Let me rephrase it.

Am I right to assume that to the extent non-commercial considerations form part of a supply decision, you would be telling the OEB that in your application?

A. MIKHAILA: For commercial arrangements where, you know, the elements that go into a decision that we have made, those material elements we would include in our evidence for decisions that we make.

N. DAUBE: Okay. Thank you. Those are my questions.

I. RICHLER: Thank you, Nick. We are going to take a break. Let's come back in one hour at five past 2:00.

--- Luncheon recess taken at 1:05 p.m.

--- Upon resuming at 2:04 p.m.

I. RICHLER: Okay. Let's go back on the record. Welcome back. Next up is Daniel Vollmer for Minogi Corporation. And, Daniel, just to confirm, the schedule that was circulated had you down as representing Minogi Corporation and Three Fires Group, but I understand that it is actually only Minogi Corporation; is that correct?

D. VOLLMER: Yeah, that is correct.

I. RICHLER: Thank you. Okay. Please go ahead.

EXAMINATION BY D. VOLLMER:

D. VOLLMER: Thank you. So I am just going to change the order of my questions to follow the responses to Ginoogaming. So to start off, as a follow-up to your earlier response to Ginoogaming before the lunch break where I think I heard you say that it isn't clear why the gas supply plan should have a section about First Nations' concerns and impacts. And then in Enbridge's responses to interrogatory 5B, Enbridge indicated that it does not support including a dedicated First Nations consideration -- or however you want it to be worded -- section in the annual update.

So I was wondering, just a quick -- if you could just explain perhaps why it is Enbridge's position that the plan shouldn't include that kind of section?

A. MIKHAILA: The framework includes the elements that we are to include in our gas supply plan, one of those being public policy, and we don't feel that the -- we're not -- it is not clear that public policy directly includes the Indigenous and First Nations matters.

D. VOLLMER: So I guess in that fifth interrogatory from Minogi, we use the OEB staff's report that, like, specifically noted that -- in the adjudicative process, that it would allow the OEB to consider whether specific First Nations' concerns need to be addressed in subsequent annual updates. So I am just wondering if the OEB staff report notes that there might be concerns, and there might not be, and then why it is Enbridge's position that there likely isn't or couldn't be?

A. MIKHAILA: I think if there are First Nations matters that, you know, those groups like yourself representing your clients feel that need to be, I think that is a matter of argument for you to argue and for us to respond to.

D. VOLLMER: Okay. But from just a general perspective of understanding these issues, this is how the gas supply plan has addressed these issues, you don't think that that should be in the plan?

A. MIKHAILA: No.

D. VOLLMER: Okay.

And then my last question is for TFG/for -- Enbridge indicated that it does not intend to incorporate the Indigenous participation proposal from the Phase II rebasing decision as part of the small volumes of RNG expected to be procured under the current voluntary RNG program. And I guess just notwithstanding your response, I was wondering if you could confirm whether that proposal could apply to the supply of RNG that is to be procured under the RNG?

A. MIKHAILA: Are you asking if it -- like, the math could work so we could do it or --

D. VOLLMER: Yeah. Basically, yeah.

A. MIKHAILA: The volumes procured are so minimal from the voluntary RNG program that the administration of, you know, that element, I don't think, is -- is not something we are going to pursue at this time.

D. VOLLMER: Okay. Thank you. Those are all my questions.

C. NGUYEN: Okay. I think we can move on to BOMA then, which is Mr. Li, I think.

C. LI: Yes. Yes. Can you -- can you hear me?

C. NGUYEN: Yes, we can.

EXAMINATION BY C. LI:

C. LI: Yes? Okay. Okay. Well, good afternoon. My name is Clement Li representing Building Owners and Managers Association Toronto or BOMA Toronto. I have a few clarification questions on your responses to BOMA Toronto's IR questions. So let's start with BOMA-2 -- actually, there is no need to go to BOMA-2 because your response actually point me to PP-2 to refer to PP-2.

So let's go to PP-2, page 2. In the second paragraph -- let me just read it. It says:

"Please see attachment 1, which outlines the 2024 adjustments applied to the demand forecast and the energy policies/signals considered when developing the adjustments."[as read]

Can you tell me when -- when did you do -- when did you develop the adjustments?

J. MURPHY: Yes. So the adjustments for this forecast were developed in Q1 of 2024 and then were applied to the 2025 to 2034 demand forecast, and the first five years of that applies to the gas supply plan.

C. LI: So Q1, 2024. So -- so thank you. Attachment 1 and attachment 2, were they developed or were they prepared around the same time?

J. MURPHY: Attachment 1 was a presentation that was given to the IRP technical working group in May and continued discussion in June of 2024. I believe attachment 2 was just prepared to respond to the IR.

C. LI: Oh, I see. But you are saying when it comes to attachment 1, the analysis was done in Q1, 2024; right?

J. MURPHY: The analysis was, yeah, completed in Q1 of 2024. That is correct.

C. LI: Right. And then attachment 2, the analysis, was done when, then? I am sorry.

J. MURPHY: If you'll just give me a second, I will just check on that.

C. LI: Thank you.

G. BASHUALDO-HILARIO: Gilmer Bashualdo-Hilario here. Attachment 2 is the result of the demand forecast being produced after we apply the assumptions developed and shown in attachment 1.

C. LI: Okay. So timing-wise, is it in 2024, or is it -- is it --

G. BASHUALDO-HILARIO: Yes.

C. LI: Yeah. Okay. So it is before -- before 2025. I see. Okay.

G. BASHUALDO-HILARIO: Correct.

C. LI: All right. Thank you.

So let's go to attachment 1. If you go to page number 4 of 13, so you see that there is -- on the left-hand side, there is "new buildings," right, and then there is "uncertainties." I see you listed "Toronto Hydro rate application," and then you said "no distinct building heat electrification forecast for '25 to '29." I just want to make sure I understand it correctly.

Oh, actually, before that, does it apply to all sectors, or this impacts only your adjustment, like, in specific sectors such as residential or commercial?

J. MURPHY: The adjustments that we made to the forecast are to the mass market forecast and are for residential and commercial buildings, but --

C. LI: No. I am talking about this specific --

J. MURPHY: -- residential and commercial customers.

C. LI: I am talking about this specific Toronto Hydro statement.

J. MURPHY: This statement on this page, it is just confirming the policy and market signals that we were observing with respect to Toronto. I would have to go back to confirm. I believe that would be for building electrification that they didn't have a forecast of existing customers that would be on gas, switching to building -- heating their buildings with electric measures.

C. LI: Right. So it applies to both residential and commercial buildings, can I assume?

J. MURPHY: I will say subject to check.

C. LI: Okay. Thank you. So if I understand this correctly, does it mean that this uncertainty makes your forecast of ET a little bit more conservative because there is uncertainty?

J. MURPHY: Yes. I think that's a fair statement. We have mixed signals.

C. LI: Yeah.

J. MURPHY: And whether that is in all of Ontario or in Toronto specifically, there is mixed signals about the pace and timing of any building electrification, and so that has led us to be a bit more conservative in our forecasting.

C. LI: Okay. Thank you.

In the same attachment 1, if you -- you don't really -- you can just go to page 8, but I am talking about if you go to page 8, page 9, page 10, I see you listed many assumptions, right. So it appears that you are describing, I guess, appliances in residential homes. So can I assume all these assumptions apply to residential customers only?

J. MURPHY: In the adjustments that we made, so the work that was done in 2024 for the 2025 forecast, the way the assumptions were put together was really based on residential, but it was also applied to commercial customers as well. I believe in the next version, so it is not applicable to this gas supply plan, we have looked a bit differently at commercial customers. But in this instance, it was applied to all residential and commercial customers.

C. LI: But I don't see any commercial. If I look at page 8, page 9, page 10, where does it say it is commercial? You just -- you are using residential figures, and then you sort of apply that to your commercial forecast? Is that what you are saying, or there are specific commercial assumptions there?

J. MURPHY: Yes, that is correct. So the reduction in the forecast or the adjustments that are made to the forecast was applied to both the residential and commercial forecasts, but it was developed based on residential assumptions.

C. LI: Residential only. I see.

J. MURPHY: The year after this, we have gone on to have a separate and distinct adjustment done -- like, calculated a bit differently for commercial. But for the forecast that fed into the gas supply plan, it was just based on the residential --

C. LI: Right.

J. MURPHY: -- assumptions applied --

C. LI: Sorry. Sorry. I am sorry. Keep going. I am sorry. Sorry to interrupt.

J. MURPHY: No, that is okay. Yeah, it was just the residential assumptions were then applied to commercial as well to come up with this.

C. LI: Right.

J. MURPHY: This -- these few slides are based on -- are for customer egress, so we used residential assumptions to come up with an egress rate, and then that was applied to residential and commercial forecasts.

C. LI: Right. Understand. But -- and, obviously, this is what you use for the application -- I mean, for this proceeding, like, this is the one, the version?

J. MURPHY: Correct.

C. LI: Okay. Okay. Thank you. That is helpful.

If you go to -- let's move on to BOMA-3 -- but then again, you point to response to PP-2, so let's stay with -- let's stay at PP-2. Okay. You talked about how you use the City of Toronto policy, different version of Toronto Green Standard, or TGS, again, listed at attachment 1, page 1. I got that. I followed that.

But if you go to BOMA-3, our question was asking -- I am asking again now -- whether you have monitored other cities in Ontario, not Toronto, but other cities such as, just picking example like Ottawa, regarding emission reduction or green policies. For example, in Ottawa, I believe they have high performance development standards, but that is just one example.

So did you -- I guess the first question is did you monitor other cities other than Toronto? And then I have a follow-up question after that.

J. MURPHY: Yes. We are monitoring the development of policies at various municipalities in our service territory.

C. LI: Right. Right. But you did not incorporate those policies in this, because it seems like you only -- you have only incorporated the City of Toronto policy into this forecast -- or into this ET adjustment; is it correct?

J. MURPHY: Yes, that's correct. We have included Toronto because the City of Toronto has some specific policies that are in place and a bit more mature than some of the other municipalities. That is to say that there is more clear understanding of the timing and the impacts that it could have on our forecasts.

And so as of the 2025 forecast, that is when we actually first included specific adjustments for Toronto. And we continue to monitor the other jurisdictions, municipal jurisdictions to see if or when it would be appropriate to include specific adjustments for those municipalities.

C. LI: So it is an informed decision that you know that there are other policies in other cities, but you are just incorporating City of Toronto policy at this point, and then you keep monitoring. Maybe in the future, you will do it, but you have not done it in this -- in this forecast; is it correct?

J. MURPHY: Yes, that's correct.

C. LI: Okay.

J. MURPHY: We are continuing to monitor.

C. LI: Do you have a list of what you monitor in terms of other cities? Like, how many are you talking about? Are you monitoring 10, 5, 20? I am just curious.

J. MURPHY: I would -- I would say that there were, I think, roughly 15 to 20 municipalities that had varying green development standards or green building standards that were in place but still in the -- being implemented. Although, I will note that now with Bill 17 that came out recently, that the Ontario government has said that green building or green development standards are not allowed. And so --

C. LI: Yeah.

J. MURPHY: -- those types of policies, you know, we are watching to see what happens with them. Do they become voluntary, or do they -- does the municipality get rid of them altogether? So we are watching the ones that had them in place, and then there was a number, you know, could be another 20 where they were working or had signalled they may implement a similar policy but hadn't yet put them in place.

C. LI: I see. Well, would you undertake to provide a summary of your review of all these activities regarding policy in other cities?

D. STEVENS: Is that something that we can pull together easily, Jennifer? Is there some sort of summary available now? I am just cautious about doing a whole lot of work on summarizing something that's (indiscernible) given your observation that recent legislation Bill 17, I believe you said, may render these somewhat toothless.

J. MURPHY: I believe we would be able to provide a summary. Perhaps it is just on a best-efforts basis, if it exists, versus creating something from scratch.

D. STEVENS: Would that work for you, Clement, that Enbridge will undertake to search and see if it has a summary of the current status of municipal green standards or similar policies and provide --

C. LI: Yeah, I can -- I can accept that, I mean, as long as, I mean, it is reasonable. I hope it is not all just yes and no, like, there is a little bit of information. But I understand best effort, so, yes.

C. NGUYEN: JT-1.13.

UNDERTAKING JT-1.13: TO SEARCH AND SEE IF ENBRIDGE HAS A SUMMARY OF THE CURRENT STATUS OF MUNICIPAL GREEN STANDARDS OR SIMILAR POLICIES AND PROVIDE IT

C. LI: Thank you. Okay. So -- sorry. Just -- okay. If you go to page 6 specifically -- I am sorry -- attachment 1 again, page 6. There you list side by side, like, Toronto-specific adjustment, and then you have Ontario adjustments. Again, Toronto, I understand you follow TGS different versions.

For Ontario, I am not sure if I understand where these figures came from. Can you explain? Oh, you know, I don't expect you to have all your numbers and analysis off the top of your head. But if you prefer to answer or you prefer to undertake to explain how you came up with these Ontario adjustments, that would be -- that would be great.

J. MURPHY: I am looking back at page 3 where we talked about the signals that we were seeing at the time that the analysis was completed for new buildings. And while at that time we didn't see any policies that would prevent gas in new buildings or, said another way, that would prevent new -- the developers of new buildings from installing gas equipment, we did see some amount of developers building without gas. It's a -- it's a pretty small percent, to our knowledge, because it is hard to get at this type of market data. But there is a small amount of builders that are building without gas today.

So we -- if we go, then, back to page 6, I think we have taken an attempt at trying to come up with, you know, what would that -- what would the impact look like. When we did this work with the adjustments to forecasts back for the rebasing application, which was the first time we started doing energy transition adjustments, we assumed that that percentage would be 1 percent. But as of this forecast, we actually made it a little bit steeper, and for all of Ontario outside of Toronto, we set that as a 3.5 percent reduction in 2025.

I will say that is maybe a little bit of a mix of future telling and, you know, reading what is happening in the market, so it might not be -- like, I don't think there is a specific source I could point you to. It is not based on a certain policies, but it is more that voluntary not attaching to the gas system.

C. LI: So it's, like, market -- market knowledge and forecasts?

J. MURPHY: Right. That's correct. It would be based on what we are seeing happening in the market.

C. LI: Right. Right. Okay. All right. So it is the same thing for '26 and '34, I guess? Similar?

J. MURPHY: Yeah. At that time, this was what we included in the forecast. I think what we are seeing today is maybe not quite as steep as we had assumed it could be. So every year, we do look at the adjustments, and we work with Gilmer's team as -- and Steve's team on forecasting, and we look at, you know, the policies. We look at the market conditions, what we are hearing from customer surveys, and we update these numbers. So at that time, this -- this -- these are the trends that we built into forecasts.

C. LI: So are you saying -- are you telling me that if you are going to do a forecast tomorrow, these numbers likely will be slightly lower?

J. MURPHY: I would say we are starting to think of this for the next forecasting exercise for 2027 forecast, and my team would look at what the current conditions are, and I would suspect that you are probably right. It may be lower today just based on, you know, different factors that are in place today that didn't exist in 2024 -- or different market conditions, I should say, that didn't -- weren't in place then.

C. LI: Okay. Okay. That is helpful.

So let's move on to my last question, which is about BOMA-5. In BOMA-5, you stated that the impact of hybrid heating systems such as electric heat pumps has not been explicitly modelled, but you did mention that the impact of that will eventually show up in a forecast due to historical consumption trend. Did I -- is it the right interpretation of your answer?

J. MURPHY: Yes. We haven't included an adjustment of forecasts for hybrid heating, but --

C. LI: Right.

J. MURPHY: -- we believe that the use of hybrid heating would gradually, as that technology becomes more -- or that configuration of equipment becomes more popular, you would start seeing the changes in our observed demand.

C. LI: So just to make sure I understand it, so can you go to CME-3, table 1. Table 1 to the next page, right. Okay. So there you -- let's just focus on commercial sectors only. So based on what you just said or based on your response provided in BOMA-5, so ET adjustments shown in columns B and D do not include any impact from hybrid or -- or -- or heat pump -- switch heat pump, electric -- electric heat pump heating system; correct?

And then -- and then the -- can I also assume that the historical consumption trend will eventually show up in the forecast that would affect column A, the base forecast under row 5, average use per customer? Is it -- is it -- did I read it correctly?

G. BASHUALDO-HILARIO: Yes, that's correct.

C. LI: Okay. Okay. Okay. That is very helpful. That is all the questions I have. Thank you.

C. NGUYEN: Okay. Thank you. I think up next we have VECC, but Mr. Garner indicated that he was having connection issues today. Is he online?

T. FEARON: No.

C. NGUYEN: Okay. So I think we can just keep moving in the schedule, which would be Energy Probe.

Tom, are you there?

T. LADANYI: Yes, I am.

C. NGUYEN: Okay. Great. Go ahead.

EXAMINATION BY T. LADANYI:

T. LADANYI: I am ready to go. Very good. So good afternoon, Panel. And if you remember from this morning, my name is Tom Ladanyi. I am a consultant representing Energy Probe. On September 10th, I sent you a letter -- or, actually, to the OEB with a copy to you, listing my areas of focus and time estimates for a technical conference, and all of my questions are related to your answers to interrogatories.

So my first area of focus is what I call the scarcity of capacity on the TCPL pipeline system. Can I have on the screen your response to Exhibit I.4-EP-1, please. A little bit more. Sorry, the other way, please. Yeah, let's go first to the question part. So I will just read you the last sentence in my preamble just to show you where Energy Probe is coming from:

"Energy Probe believes that home heating with electricity will become more costly in comparison with natural gas over the forecast period, and the decline that Enbridge is predicting will not happen."[as read]

So that is our belief, and it is contrary to a belief of many of the parties in this proceeding.

And in part A:

"Has Enbridge considered what it needed to do if there is growth instead of decline in demand over the forecast period?"[as read]

And in your response, you stated:

"As noted in the five-year gas supply plan, scarcity of existing pipeline transportation capacity continues to be a concern as Enbridge Gas has observed that available capacity has become increasingly scarce."[as read]

Now, as some of you may know, I worked for TCPL for many years. I worked for TCPL in the '70s and the '80s, and I was involved in pipeline construction in northern Ontario. In fact, I was in charge of pipeline construction in northern Ontario in the mid '80s. So I am very familiar with the issues with pipeline expansion. I was also on the TCPL tolls task force when I worked for OPG for a number of years.

So can you tell me -- and I have not researched this. Maybe you can tell me. So as far as I know, TCPL has three pipelines through northern Ontario, and a few years ago, line 2 was out of service because of corrosion issues. Has line 2 been placed in service, or is it still out of service? Would you know that? Because that would affect capacity.

S. DANTZER: Yeah. Good afternoon. It is Steve Dantzer. We are not aware of the specifics with respect to mainline capacities or constraints or the inner workings, kind of, that you are referring to in that question, so I can't really comment.

T. LADANYI: Yes. So what I am getting at, have you had any discussions with TCPL about their potential expansion in northern Ontario? For example, building another pipeline? Because I understand TransCanada would build a pipeline if one signs a long-term contract with them. Have you had any of those discussions?

S. DANTZER: Sorry, just give one second, please.

A. STIERS: Hi, Mr. Ladanyi. It is Adam Stiers. So I think the best response we can probably give you to this one is supported by our response to STAFF-5. There we explain that the company is in regular discussion with TransCanada and continues to participate in open seasons, both for existing and new capacity annually or whenever open seasons are released, and depending on the nature of the capacity and the services that are offered. We --

T. LADANYI: I think --

A. STIERS: -- we go on to assess any capacity that ultimately becomes available relative to its forecasted need.

So you are asking about whether or not we have explicitly pushed for expansion capacity. I think we are communicating with TransCanada our needs, which are also described in detail throughout this application, the specific delivery areas where we are experiencing constraints, and would look for opportunities to support new or existing capacity open seasons to serve those areas in the future.

T. LADANYI: Okay. Thank you. Can you tell me a bit more how that is progressing, these discussions with TransCanada. You told them what your needs are. I am sure they are aware of it. Is there a possibility they are actually coming back with some kind of response to you? Can you tell us a little bit more about how this is progressing.

A. STIERS: I am not aware of any novel projects being developed for new capacity at this time, but perhaps somebody else is.

S. DANTZER: The only thing I can add is, you know, as this interrogatory response STAFF-5 outlines is we have participated in recent open seasons, and, you know, any incremental capacity is publicly listed on the contract demand energy report that you are probably aware of.

T. LADANYI: So is there another open season coming up this fall? Would you be aware of that?

A. STIERS: So there was just an existing capacity open season and a new capacity open season. I am not sure all results of those have been posted, but the company did assess and, where appropriate, participate.

T. LADANYI: Okay. I won't press you any more. It is probably confidential what your strategy is. And really, for the purpose of this technical conference, we don't have to know the details. I am very pleased to know that you are participating in the open seasons and that you are looking for the best solutions for the ratepayers.

A. STIERS: We are.

T. LADANYI: So my next area of focus is the impact of Iroquois pricing on peaking services. And for that, can you turn to Exhibit I.5-EP-2, Energy Probe 2.

So is Enbridge concerned that it may be relying too much on peaking capacity, peaking services and increasing cost of such services due to lack of availability of pipeline capacity? Can you discuss that with me? Do you feel like there is -- and I read your evidence. I feel there is too much belief that you can meet the needs of your customers with just with peaking capacity, but peaking capacity is kind of volatile, isn't it? Is this what you say in this response?

A. MIKHAILA: I think we share the concern about the, you know, future reliance on peaking services and the lack of available transportation capacity in light of options available to us. There might not be other options to serve the demand and peaking services being that last option available to us. But we do have concerns with the quantity as well as the potential price risk associated with them.

T. LADANYI: Now, the commodity price risk, the bottom of the page -- if you can scroll up a bit, you can let me see more of it on the screen. You mention Iroquois and the effect it has on the pricing. And I should mention, by the way, since unlike Kate I have been in this business for more than five decades. Okay. So I started in the '70s. And at one time, I was actually working on the Iroquois project, and I testified on behalf of Iroquois before the New York State Public Service Commission in '86 and '87.

Anyway, leaving that aside, why would Iroquois pricing have a large impact on the market area of Enbridge Gas considering Iroquois is really just kind of like a lateral of the TCPL system?

A. STIERS: In our experience through the RFPs that we conduct for peaking services annually, the price for services is typically tied to Iroquois as a pricing point.

T. LADANYI: So you watch Iroquois closely to see what is going on there all the time. Is that right?

A. STIERS: We do, yes.

T. LADANYI: Okay. Thank you. My next area of focus is the impact of tariffs on gas supply planning. Can you please turn to 1.2-STAFF-10. And in A, STAFF asked:

"What volume of gas currently transported through U.S. pipelines under Enbridge Gas's gas supply plan would be subject to any Canadian imposed tariffs? Please also identify as a percentage of total supply."[as read]

And you provided an answer, which is on the next page. That is right. It says:

"Of the 531,283 TJ of '24/'25 annual supplies, approximately 289,719 TJ per day could be subject to any Canadian imposed tariffs, approximately 55 percent."[as read]

I would like to better understand the problem of the tariffs. And now I would like you to turn to figure 11 of your evidence, if it is possible, which is on page 62. Now, my screen is on PDF 65 and -- I think this is good, yes. Okay.

So I am only putting this up for the purpose of discussion, so see what we are talking about. So you can see the yellow line which is the Great Lakes Gas Transmission, which is operated by TransCanada pipelines, and I think it is maybe wholly owned now. At one time, it was 50 percent owned. So let's talk about that pipeline for a minute.

So gas gets off the TransCanada mainline, which is the red line, and enters the U.S. in Manitoba. Okay. And goes south of the Great Lakes, and then re-enters Canada south of Sarnia. And so gas that comes in from that pipeline, would it be subject to tariffs entering the U.S.?

A. STIERS: Your premise was Canadian retaliatory tariffs. Now I believe you are asking if U.S. tariffs would apply to --

T. LADANYI: Yeah, actually, I --

A. STIERS: -- the gas volumes transiting the U.S.

T. LADANYI: Yes, that is --

A. STIERS: So I will just restate it to make sure I understand it.

T. LADANYI: Yes.

A. STIERS: So Canadian origin, national origin, volumes transiting the U.S. en route for consumption in Canada again, would those be subject to U.S. tariffs is the question.

T. LADANYI: Possibly, but let me explain to you the problem here because that is why it -- it is a much more complicated problem, at least in my mind. Maybe you understand it all.

So as far as I understand, the Great Lakes Gas Transmission system, certainly Canadian gas comes into the U.S. in Manitoba, and then it goes south of the Great Lakes. Now, all of that gas does not re-enter Canada. A lot of that gas ends up with American gas distribution companies along the way, you know, in Wisconsin and Minnesota and Michigan, and some might even end up in Chicago.

A. STIERS: Yes.

T. LADANYI: Then along the way, that pipeline picks up American gas in Michigan. So when the gas molecules re-enter Canada, that pipeline has got Canadian and American gas. So since you want to talk about Canadian retaliatory tariffs, on re-entry to Canada, does Canada apply tariffs only to the Canadian molecules or only to the American molecules or both American and Canadian molecules?

A. STIERS: So what I would say in response is there aren't any Canadian retaliatory tariffs, so we can't say how that would work. I can give you a sense of whether or not or what has applied from a -- and I believe we have responded to this in both STAFF-10 and CCC-12, what volumes or magnitude of U.S. tariffs have applied to volumes, Canadian gas transiting the U.S. That is all that has applied, and it has not been material to date.

T. LADANYI: So there are no tariffs on gas no matter what the source is on re-entry into Canada south of Sarnia? The gas ends up all at Dawn, so there are no --

A. STIERS: With the exception of a very immaterial volume that was transiting before an exemption under the U.S. MCA or CUSMA, exemption applied to those volumes which was basically from March 4th to March 6th of 2025. There is no tariff being applied to the volumes that we are procuring.

T. LADANYI: Now, this morning I was listening, and there was discussion about Vector, and I was -- remember, I have been five decades in this business. So Vector is actually the extension of the Alliance Pipeline which goes from northern BC, across Alberta and Saskatchewan, enters the U.S., and ends in Chicago area. And then Vector was built after that to take those volumes and any other American volumes from Chicago area into Canada.

So you mentioned -- you never mentioned gas from BC. Do you actually get any gas from BC, or are you are calling it all Alberta gas, but, in fact, some molecules might, in fact, be from British Columbia.

A. STIERS: Again, and I don't -- I say this for the benefit of the record, not necessarily you, Mr. Ladanyi, you are well aware of the integrated nature of North America's natural gas system and that molecules aren't tagged in any shape or form.

The premise of our responses has been that, for all intents and purposes, the volumes that we're purchasing at AECO or Empress are Alberta gas. Western Canadian, we call it. Whether or not it is possible that some amount of British Columbia could be in there, I cannot say.

T. LADANYI: And similarly for the Vector volumes that you get in Chicago, they are essentially bought -- they are from the Chicago which has Canadian and American gas. That's right? So it is -- and also including possibly British Columbia gas for all we know. And that gas gets into Canada to Dawn, and it is without tariffs, and it is not affected in any way by the tariffs. In fact, tariffs don't even enter your planning. Is that right?

A. STIERS: They don't apply at this point in time, no.

T. LADANYI: Okay. I have a better understanding. Thank you very much.

Now, I have just one more area of questions. If you can turn to Exhibit I.5-EP-4. Can we have that on the screen, please. And I asked you for the reasons of the changes, and you said:

"The decrease in in-franchise supply in the Enbridge CDA over the forecast period is a result of a reduction to direct purchase customer supply (Ontario Transportation Service) as some customers will shift their delivery from the Enbridge CDA to Dawn effective November 1st, 2025."[as read]

So this is more in the area of -- that my friend Dwayne should have been asking this morning. Or maybe he knows all these answers already.

So how do you know in June 2025 when you filed your updated evidence that this will happen effective November 2025? Did you have some indication? Or, like, how would you know this event is going to happen in the future?

A. MIKHAILA: We had a request from some OTS customers to shift their obligation from the Enbridge CDA to Dawn. And as part of our planning for the gas supply plan, we recognize the ability to provide that shift to those customers, and so we permitted it, and so we were aware that they were going to be shifting their obligation point at that time.

T. LADANYI: All right. So you know it is going to be -- you have a fairly good idea how many, what the volumes would be, you would say, or you are expecting some more than -- now? Or you can know everything now and have a really good idea of what is going to happen November 1st?

A. MIKHAILA: We know the exact volumes based on the customers who provided the request, and we permitted it.

T. LADANYI: So they have to provide the request in advance. Is that right?

A. MIKHAILA: Yes. We have to ensure we have the facilities able to meet the request.

T. LADANYI: And if you don't agree to the request, they just can't do it. Is that right?

A. MIKHAILA: That is correct.

T. LADANYI: You will be happy to know that these are all my questions. Thank you very much.

I. RICHLER: Thank you, Tom.

Okay. Up next, we have Pollution Probe. Mr. Brophy, are you on the line?

M. BROPHY: Yes. Can you hear me?

I. RICHLER: Yes, we can. Please go ahead.

EXAMINATION BY M. BROPHY:

M. BROPHY: Okay, great. Thank you. I just need to switch the view because when I have it in the main view, for some reason, all the controls disappear, which has never happened before. So it may take me a second in between.

Good morning, Panel. My name is Michael Brophy. As I mentioned this morning, I am here today representing Pollution Probe. And it looks like hopefully we will be able to get through all of our questions today and not split until tomorrow which will take away the -- any issues with the witnesses that won't be able to attend after today.

Okay. So the first question relates to STAFF-11A. And you can pull it up if you need, but I will give you the context. So Enbridge's response to STAFF-11A indicates that the Province's Integrated Enbridge Plan, or IAP as it is referred to, is a new policy document and that Enbridge is still assessing or hasn't fully assessed what this policy document means for Enbridge. Do I have it right so far?

J. MURPHY: Yes, that is correct.

M. BROPHY: Okay. Thank you.

And so it sounds like Enbridge hasn't done any analysis related to the IP on its business, but if you look at the response to Pollution Probe 13, it shows that somebody at Enbridge went through the full document to find the references to natural gas, and they referenced -- they seem to fall in about two to three pages buried in the 152-page provincial IEP. So who did that analysis?

A. MIKHAILA: Those references were -- if you want to call it an analysis or the -- you know, the references to natural gas and the policy statement or the natural gas policy statement included in the integrated energy plan was done in response to provide an answer to this undertaking where it -- you know, the question gave a reference that maybe there was limited references to natural gas and that was somehow indicative of the importance of natural gas in the future and that -- the references to natural gas in the integrated energy plan was completed to provide an answer to that interrogatory.

M. BROPHY: Okay. So the analysis done to respond to Pollution Probe 13 is the only analysis irregardless of the answer to STAFF-11A. So Enbridge's initial response is there was no analysis, but then you did the analysis to respond to Pollution Probe 13 so --

A. MIKHAILA: I wouldn't call the answer to Pollution Probe 13 an analysis.

M. BROPHY: Okay.

A. MIKHAILA: I think it was a review of the document to indicate where natural gas had been stated in the integrated energy plan.

M. BROPHY: Okay. Okay. That is my understanding, so thank you. I just wanted to make sure I had that clear.

The next reference is GFN-3A, and it relates to questions from GFN on Enbridge's achievement -- or assessment of one of the three principles, which is achieving public policy. So in the response to GFN-3A, Enbridge indicates that:

"Enbridge Gas follows the guidance set out in the following two OEB decisions and guidance documents when determining the subjects to be included in section 6."[as read]

So the achieving public policy elements. And Enbridge referenced those two documents; one is section 3.1.4 of the framework for the assessment of distributor gas supply plans, and the second reference that Enbridge gave was OEB staff recommendations outlined in the OEB staff report on the review of the 2024 annual update of Enbridge's gas supply plan. Does that sound familiar so far?

A. MIKHAILA: Yes, that was the response.

M. BROPHY: Okay. Thank you. And so those two references of what Enbridge looks at when determining what to include or assess for public policy elements of the gas supply plan. Those two documents are fairly high-level reference documents. They are not kind of detail, paint-by-number instructions to Enbridge, but they lay out high-level requirement.

So could you be more specific on how Enbridge applies that high level to ensure that all relevant public policy issues are identified and adequately reflected in the gas supply plan? Do you have any other process, or do you just -- whoever the staff is that is charged with that for each gas supply plan reads those two and determines what that means? How does that work?

J. MURPHY: Yes, so Enbridge looked at the guidance, and as you noted, it is not very specific. So we looked at the guidance provided in those two references, and we determined that, broadly, climate policy or energy policies that would influence our customer's demand or their supply types, that those were relevant policies that we would look at in the gas supply plan.

M. BROPHY: Okay. So given that you are answering, Ms. Murphy, it is the energy transition team that reviews it for that purpose, or is it the gas supply plan team? Or both, perhaps?

J. MURPHY: I would say it was a combination of both where we discussed the types of policies that we believed were relevant, and then, yes, my team looked at any energy or climate policies. And I believe there is a section in there as well on tariffs, and that would have come from the gas supply team.

M. BROPHY: Okay. And was there any third party review or input to see if there was anything missing, or it was just Enbridge's judgment on what made sense?

J. MURPHY: There was no third party input.

M. BROPHY: Okay. Okay. Thank you.

The next question is related to Pollution Probe 15. So there is the question there, and then attachment 1 is in the response as well. So just while you are pulling that up, I will ask the first question. So it shows a new diagram that links Enbridge Gas supply into the IRP process. And when was that new process diagram established?

A. MIKHAILA: The process diagram that was included in the question, my understanding, was originally part of the IRP hearing but didn't necessarily reflect the decision from the IRP hearing. And so in order to create a document that did reflect the decision, we prepared diagram 1 from Pollution Probe 15, attachment 1, in response to the question asked in the interrogatory.

M. BROPHY: Okay. So when was that new diagram established?

A. MIKHAILA: The later half of August 2025.

M. BROPHY: Oh, so recently. Okay. And, you know, as you noted -- and I don't remember all the details in the decision back in the IRP, that was 2021, but, you know, I don't think the board specifically approved or denied the old diagram, and there has been some proceedings and discussions on IRP since then. So your understanding is that the new diagram reflects everything related to IRP up to, you know, that date you gave in 2025. Is that right?

A. MIKHAILA: That is my understanding. This isn't an internal process diagram that we use. We created it to respond to the interrogatory.

M. BROPHY: Okay. And that is helpful too because my next question was does this sit in an Enbridge policy manual somewhere? And, well, you can answer the question, but I am assuming --

A. MIKHAILA: No, it does not.

M. BROPHY: Okay. And when I compare the original diagram to the recently updated one, it looks like the updates was really just to move the IRP assessment boxes to after the asset management plan is developed. Is that -- that is the only changes really. Is that correct?

A. MIKHAILA: Yes, that is my understanding is the IRP official process -- I am not sure -- begins or is initiated once there is a project identified in the AMP.

M. BROPHY: So my understanding, and I won't go too far into the weeds because it would link back to decisions and requirements from the OEB but -- is that Enbridge needed to consider IRP in developing the AMP. So I was a little confused. If you have moved it after the asset management plan, it means IRP is not considered.

A. MIKHAILA: I think there is first a need identified. A project is created for purposes of the AMP. And then prior to proceeding with that project, the IRP process is initiated to determine whether that project can be deferred, delayed or cancelled. But at the first start of the IRP process is a project need identified in the AMP.

M. BROPHY: If a project could be deferred, delayed or cancelled, wouldn't you want that to be reflected in the AMP? Because, otherwise, the AMP doesn't reflect your current reality of your planning. Do you see what I am saying?

A. MIKHAILA: I can't really speak to the AMP process, sorry.

M. BROPHY: Okay.

J. MURPHY: I could just maybe add the AMP document does have an appendix that includes the IRP analysis.

M. BROPHY: Oh, in the IR, you mean? The IR response?

J. MURPHY: No. Sorry. In the asset management plan, there is an appendix --

M. BROPHY: Okay.

J. MURPHY: -- that -- as Ms. Mikhaila is saying, the needs are identified. And there is a project that is defined in our asset management plan, but also in the asset management plan, there is analysis as to the IRP assessment. That is presented in the AMP as well to show where we feel there could be an IRP alternative implemented.

M. BROPHY: Well, I guess that is one of the reasons I was confused as well because you would have to do some IRP analysis in order to put that into the AMP, so -- but it sounds like it is a fairly new diagram. It hasn't really been tested out per se and kind of --

A. MIKHAILA: The diagram might be something we prepared for purposes of the interrogatory, but this is the process that we do follow.

M. BROPHY: The process laid out in attachment 1 of Pollution Probe 15?

A. MIKHAILA: Yes, that is correct.

M. BROPHY: Okay. And I think I know the answer to this, but given that you developed that new process diagram recently this year, I am assuming there wasn't any stakeholder consultation or OEB review of that yet. Is that right?

A. MIKHAILA: My understanding is the process diagram reflects the IRP decision on how we are meant to approach IRP. I don't know if Ms. Murphy has anything else to add.

M. BROPHY: I guess the question is even more simple. This is the first time we are seeing the diagram. That is correct? A new diagram.

A. MIKHAILA: It is the first time you are seeing the diagram, yes.

M. BROPHY: Okay. Yeah, thanks. I am sure we could spend hours on IRP, but I am trying to stay out of the weeds, if possible, on that. Okay, thank you.

Okay. So the next question is on Pollution Probe 2, and it is attachment 1, page 9. I can give you the reference again if you need it. That includes a table of probabilities for customer disconnections from the natural gas system based on the number of natural gas appliances that they have. Yes, that is the one. Perfect. We see it on the screen now.

So for the probability of connection number shown in that table, can you provide the analysis and documentation you used to calculate those values?

J. MURPHY: Just to clarify, you are referring to the probabilities on the right-hand column?

M. BROPHY: Right. Correct, yes.

J. MURPHY: I am not sure that we have anything that we could provide. Those numbers, I don't think there is a calculation, per se, behind them. We did look at our residential customer surveys to understand the percentage of customers -- so the column in the middle -- that have one appliance, two appliance, or three plus. So that -- that is grounded in a residential end-use survey, which I am certain is filed somewhere. Although I can't think off the top of my head which -- if that is in rebasing or where that would be filed, but that type of survey is frequently put on the record.

The probability of system disconnection is more of an art than a science, where we have made some assumptions based on the number of appliances. So we are assuming that if a customer gets to the end of their equipment lifespan and they only had one piece of equipment that -- and keep in mind, this was done in 2024 for the 2025 forecast -- that at that point in time, we assumed that with one appliance reaching the end of the life, that there -- we just were very conservative and said they would electrify.

Then for customers with two appliances where one of those gets to end of life, we thought, well, is that -- you know, would that be hundred percent? We think probably hundred percent not likely. And we came up with a value of 25 percent and then repeated for three or more where we've said, well, if one piece of equipment dies, say -- say you have a furnace, a water heater, and a pool heater or gas stove or whatnot, it would be a much smaller probability that customers would fully electrify their whole home and detach from our system, so we have put that at 5 percent. But I don't think there is anything we can really point to as much in this case.

In the next version after this one, so the one that we did in '25 that would feed into the 2026 forecast, I think we have refined that approach a little bit more and tried to use a bit more of the -- what customers are telling us around their preferences for gas.

And in this one as well, I will say, like, if you look at the information above the table, we did have customers saying that -- about 26 percent said at the end of their equipment life, they would replace with a non-gas option. So we did try to tie into that a bit, but it is difficult to determine what customers will do once they get to that purchasing decision.

M. BROPHY: Okay. No, I appreciate that response. And I understand that, you know, it's Enbridge staff kind of, you know, judgment or -- you know, I am not -- I am trying to not use the word "analysis" because you don't have, like, written documented analysis on those figures.

So the new version that you have done, does it have any math that kind of links those numbers, or -- or, again, is it just staff judgment to land at the probability of system disconnection?

J. MURPHY: I think I would have to go back to check to see what math is around it. As I said, it is based on feedback from customers from the residential end-use survey, as was this, as you can see. But any -- like, what those numbers would be for the next version, I don't have that with me today.

M. BROPHY: Okay. So if you could undertake to go back and take a look, and if it is exactly kind of the same as what is here with no additional kind of information that would help us understand it, then you can choose whether you file it or not. But certainly if there is anything there in the new analysis that helps us understand the analysis that would be done, that would be -- that would be helpful if you can file that.

D. STEVENS: I think that will show up, as Jennifer was saying, Mike, in next year's update. The demand forecast that was used for the five-year supply plan was premised on the ET adjustment explained in this presentation. So we are getting ahead of ourselves to start looking at filing and questioning and understanding subsequent adjustments. I think that is better done in the context of the next demand forecast, which will be in the next annual update.

M. BROPHY: And I can appreciate that and certainly look forward to the next annual update if there is additional useful information there. The -- I guess the challenge, David, is that, you know, if this doesn't look right based on, you know, a review of the information that is available, as Ms. Murphy had mentioned, you know, we have looked at the survey information and, you know, the same kind of things that Enbridge staff looked at to come up with those probabilities.

And I guess the challenge is -- and I know you said earlier, David, that you don't know the OEB's process going forward, that they may have an oral portion, they might just go to written submissions, you know. It is unclear to all of us how the Board intends to unfold the process.

But, you know, if we were to lay out issues and then Enbridge came back and started referring to new analysis and rationale that you are saying you don't really want to provide in this proceeding, then I think it would be -- that would appear a bit unfair that, you know, you would be including information that we had asked to see and you didn't provide. So that is -- you know, if you are saying that you wouldn't be using that in this proceeding, then, you know, we could probably wait until the next one, but certainly interested in anything that helps us understand these numbers a bit better because they didn't -- they didn't look right to us.

D. STEVENS: Sure. Well, thanks for that explanation, Mike. I absolutely agree with you that it would be entirely unfair for us to start relying on things once they became convenient to us and that we declined to provide to you. So that's certainly not something that we are planning to do, but we are hoping to keep the scope of this case to -- to the forecasts that are set out in this case, not what is coming up in future years.

M. BROPHY: Okay. Thank you. I will move on.

So the next question is in relation to SEC-1. And in attachment 1 to that interrogatory, Enbridge provided the Enbridge Gas Inc. Gas Supply Procurement Policies and Procedures dated July 23rd, 2021. And, well, I guess the first question is, is there separate gas supply manuals for Union and Enbridge, or have they been fully integrated into one now?

A. STIERS: No. This is the sole policy document.

M. BROPHY: Okay. So that's -- that's a fully merged utility. And I think based on the question, I am interpreting that that is all you have? That is the totality of the internal, you know, protocols and guides and reference that reflects Enbridge's gas supply area? Is that accurate, or is there another manual somewhere?

A. STIERS: This -- this is full representation of our procurement policies and practices within the gas supply department.

M. BROPHY: Okay. Thank you. And then just because it is dated July 23rd, 2021, so there has been no update since July 2021; correct?

A. STIERS: Correct.

M. BROPHY: Okay. And you probably agree that it is, you know, a long time ago, several years ago. So has there been any reviews done since July 2021, or no?

A. MIKHAILA: Yes. It was reviewed, at least within my time within the gas supply department -- I believe it was last fall -- and deemed that there was no changes necessary at that time.

M. BROPHY: Okay. So that is just an internal review. They said, we don't see anything, so you didn't have to, you know, write up reports or go up the chain with that? You just -- is that correct?

A. MIKHAILA: That's correct.

M. BROPHY: Okay. Thank you. And I didn't see anything in this gas supply manual that relates to scorecard or metrics; is that correct?

A. STIERS: Yeah, subject to check, I think that is right, Mr. Brophy.

M. BROPHY: Okay. So then if Enbridge's gas supply manual doesn't have any direction in relation to scorecard and metrics, where does that come from?

A. STIERS: Sorry. You mean within the gas supply plan itself, where does the scorecard --

M. BROPHY: Correct.

A. STIERS: You're referring to a scorecard? We would refer to it as the performance metric section.

D. STEVENS: Sorry. I just wonder if we are -- are we at cross purposes here? Are you speaking about sort of employee scorecards, Mike, or are you --

M. BROPHY: No.

D. STEVENS: -- speaking of the scorecard that is found within the gas plan reporting each year?

M. BROPHY: The second. So, yeah, I guess if there is nothing in the manual, that is done outside somehow.

A. STIERS: So the procurement policies and practices manual doesn't include any section because the performance metric requirements are specific to the OEB framework and deal solely with the gas supply plan and the presentation and tracking of that plan.

M. BROPHY: So, yeah, I think I understood about half of that. But the -- so the gas -- the OEB requirements don't -- do not dictate scorecard in the metrics for Enbridge. Enbridge chose those, so then there is decision-making at Enbridge on metrics and scorecards being done. And, sure, you had been, you know, filing them in your annual plans for review, I wouldn't say approval, but at least review annually for five years. But I guess that process to develop or to change those metrics, that is just -- it is just something that is done outside the gas supply manual process, then; is that right?

A. MIKHAILA: I think that is fair. This document we have turned up is the procurement policies and procedures, and I don't think that the performance metrics are part of these policies and procedures.

M. BROPHY: Okay. So if there is no kind of written guidance on gas supply metrics and scorecard in any manual, would it be fair to say that that is just management and staff discretion at Enbridge, then? You look at it. If you think a change is needed, you do it, but it is not -- there is no -- no written guidelines, then, other than the broader, you know, OEB, you know, requirements that you would apply; is that accurate?

A. MIKHAILA: Yes. I would say we would review the performance metrics, and they have been reviewed through the annual update process of filing the gas supply plan.

M. BROPHY: Yeah.

A. MIKHAILA: And, you know, where we have heard feedback of changes, we have incorporated those. And as we prepare it annually, we may review it to see if there is anything else that we would like to add, but there isn't a manual document or -- that describes how we go about doing that.

M. BROPHY: Okay. Thank you. And I am trying to remember back to five years of annual plans, but I -- I can't remember if there were changes or not. But I know some of the changes, you know, suggested by parties weren't made, so, again, that is up to the discretion of Enbridge at this -- at this point, whether you make those changes; is that correct?

A. MIKHAILA: We definitely have made changes throughout that time period, and that has come through feedback in the annual update process as well as, as you hopefully have seen, the targets and variance ranges we added this year.

M. BROPHY: Oh, yes. Okay. Thank you.

Okay. The next question is on STAFF-13. And you were talking about the asset management plan earlier with Environmental Defence, and it was noted in STAFF-13 that there is -- there is information in an asset management plan addendum that is going to be coming this fall that links to -- I think it is transmission projects that were part of the analysis that you are using, and so, you know, we are kind of middle of September, so when -- when would the AMP addendum -- when is the plan to file that?

D. STEVENS: The -- I am just looking, and the witnesses don't seem to have a definitive response, Mike, but --

M. BROPHY: Okay.

D. STEVENS: -- historically what has happened is it has been filed during November, like, either the very end of October or during November of a year.

M. BROPHY: Okay. November. And then I guess there is a notice that goes out to parties; is that the way it works?

D. STEVENS: My recollection is it has been provided to parties in the last major rates proceeding.

M. BROPHY: Okay. So then it would be -- it would be -- if it is filed, say, October or November, then -- because you are already in your 2026, right, if it's the case, so it would be 2027, I guess? Is that --

D. STEVENS: Again, subject to confirmation, I think it is filed under an older docket number. I don't think it is filed as part of -- there is no approvals being sought, so I wouldn't expect it is actually being filed as part of a --

M. BROPHY: Sure.

D. STEVENS: -- forward-looking rate application.

M. BROPHY: Okay. So is it possible for you just to take that away and let us know when you think it will be filed? And if there is a standard old docket number that you use, maybe just provide that.

D. STEVENS: Yeah. Maybe it is easiest for us just to do that by undertaking.

M. BROPHY: Okay. Thank you.

D. STEVENS: Turning around. So we will advise as to when the AMP update will be filed during 2025 and under what docket number.

M. BROPHY: Thank you.

I. RICHLER: Let's mark that or record that as JT-1.14.

UNDERTAKING JT-1.14: TO ADVISE AS TO WHEN THE AMP UPDATE WILL BE FILED DURING 2025 AND UNDER WHAT DOCKET NUMBER

M. BROPHY: Okay. Thank you. Okay. The next one, I am going to skip. I think you answered that with your BOMA discussion.

Oh, okay. So this is -- when we were talking about scorecards, I was thinking of asking --

I. RICHLER: Mike -- Mike, sorry. It's Ian. I am sorry to interrupt, but we're -- I am just looking at the clock. We are due for our break. Is now an okay time for us to do that, or do you need to finish?

M. BROPHY: Sure. No. That sounds fine.

I. RICHLER: Okay. Well, let's take -- let's take 15. Let's come back at 3:45, actually. Okay. Thanks.

--- Recess taken at 3:29 p.m.

--- Upon resuming at 3:45 p.m.

I. RICHLER: Mr. Brophy, you ready to resume?

M. BROPHY: Yes.

I. RICHLER: Please go ahead.

M. BROPHY: Okay. Great. The next question I have is in relation to Pollution Probe 5D, and it links back -- just before the break, we had talked about the scorecards a little bit. And in Pollution Probe 5D, you will see the response says that:

"The percentage of certified gas in the portfolio was added to the performance metrics as part of the 2023 annual update in response to stakeholder interest."[as read]

Does that sound right? I think it is on the screen now.

A. MIKHAILA: Yes, that is correct.

M. BROPHY: Okay. And I didn't want to ask this for all the changes, but this one jumped out to me in particular, because I recall that there has not been much support for certified natural gas over the past few years as part of the gas supply plan discussions. And is there a specific reference that you have from the 2023 annual plan, which stakeholders asked you to add it?

A. MIKHAILA: I think it was part of the questions asked, and we included it in our annual update presentation, so that was transcribed, and I believe it was on the record there. I could go back to the questions and ask -- and look, but I believe Pollution Probe was one of them.

M. BROPHY: Okay. Yeah, if you wouldn't mind, that would be great just to find where the linkage came from. Because I remember lots of discussions about it doesn't actually cost ratepayers anything more because it is not one of your criteria that then you use that increases the costs in your procurement. I remember that because then --

A. MIKHAILA: I think I want to be careful when we say that it doesn't cost ratepayers more. The way we procure certified gas does not cost ratepayers more. If we were to have a strategy and try to achieve a certain level of certified gas, that would come at a cost to ratepayers.

M. BROPHY: Yes. Yeah, fair enough. So, yeah, if you can -- you can let me know the response, that would be great.

D. STEVENS: To be clear, Mike, are you asking which stakeholder asked for percentage of certified gas in the portfolio to be added to the matrix and when?

M. BROPHY: Yes. Yeah, that would we great.

D. STEVENS: Okay. Well, we can see what we can find out.

I. RICHLER: That will be JT-1.15.

UNDERTAKING JT-1.15: TO ADVISE WHICH STAKEHOLDER ASKED FOR PERCENTAGE OF CERTIFIED GAS IN THE PORTFOLIO TO BE ADDED TO THE MATRIX AND WHEN

M. BROPHY: Okay. Thank you.

The next question is on Pollution Probe 26, attachment 1, which includes the most recent gas supply plan approval deck for Enbridge senior management. And it -- the response to Pollution Probe 26 indicated that the presentation and approval of the gas supply plan occurs in September each year. So if it is approved in September each year, I guess the question is why can't the gas supply plan be completed and filed in, say, end of September or mid-October, that kind of timeline, if it is already approved by Enbridge?

S. DANTZER: So the approval of the gas supply plan that is reflected in this presentation approves -- well, as part of that contracting decisions for the upcoming gas supply plan effective November 1st of that year, and so those activities typically would follow this internal approval process.

A. MIKHAILA: And we should note that there is quite a bit of effort involved in preparing the actual regulatory filing itself as well. So although the gas supply plan may have approval, there is a significant effort to prepare the evidence required for the regulatory process, which isn't an immediate turnaround. But once the plan is approved, the contracting decisions occur, and it is also at the busiest time of our department's year, which is during the winter, start of November.

M. BROPHY: And that is exactly, you know, why I asked. So it sounds like, you know, the ingredients are in the, you know, approvals that you gained from Enbridge management in September, but the time to pull together what you are going to file and -- and especially given that it is a busy time for you, then that is what pushes it out longer, I think; is that -- is that correct?

S. DANTZER: That's fair. I would also just add to that that there is additional information as part of the framework that is required, namely the three-year historical review information that is not actually available until the following year.

M. BROPHY: Okay. Okay. Thank you for that.

And so if we can go to page 3 of the document that is on the screen, so that is Pollution Probe 26, attachment 1. So this is kind of the -- you know, the ingredients that go into your kind of gas supply planning, and I won't walk through every slide after this. But, you know, there is some things I was able to map to, you know, what is in the materials that you filed, so portfolio alternatives and costs, evaluation of guiding principles that came from the OEB framework, design day requirements you have talked about. So the long-term strategy, is that something that was filed? That is the only piece I was missing.

S. DANTZER: There is nothing specific with relation to the long-term strategy. I would say that is sort of embedded throughout a lot of the themes that you see in our gas supply plan filings. You know, longer-term demand forecast, even, like, something like scarcity of supply, that is some of the elements of a longer-term strategy.

M. BROPHY: Okay. So is the long-term strategy, like, a document, or it is just, like, a term of phrase meaning that you look into the future on all the other things?

S. DANTZER: Yeah, it is the latter. There is no --

M. BROPHY: Okay.

S. DANTZER: -- document for it, yeah.

M. BROPHY: Okay. That is -- I think that is why I was confused. Thank you.

Okay. And this should be my last question, and it relates to FRPO number 7. And in FRPO number 7, the response says that the gas supply plan evaluates cost effectiveness on the basis of the total annual portfolio costs, which is comprised of commodity, transportation, and storage costs. When evaluating incremental contracting alternatives, Enbridge Gas evaluates the cost effectiveness of contracting alternatives by comparing changes in the total portfolio cost, and then you give an example reference.

So my understanding of that answer is that incremental gas supply decisions are made by comparing those costs against the base portfolio costs in dollar per gigajoule and, you know, against the base gas procurement portfolio; is that correct, or is it something different?

A. MIKHAILA: That is not correct. I think we discussed this a little bit with Mr. Quinn this morning. It is really on a total portfolio cost basis, so total cost of the gas supply plan, not on a per GJ basis.

M. BROPHY: Okay. So if any incremental decisions you make are equal or lower than your portfolio costs before you apply that incremental decision, then that is -- that is a green light for you, and if it is higher, then that kind of pushes you to challenge it more; is that -- is that correct?

A. MIKHAILA: No. I wouldn't characterize it that way. I would say when we have alternatives -- where we have a shortfall, for example, and there is alternatives to meet that shortfall, we would evaluate each of those alternatives through what we have referred to here as a holistic analysis by including meeting those shortfalls in the gas supply plan and assessing how the optimization model handles the alternatives of meeting that shortfall and the cost that comes -- comes along with each of those alternatives and then assessing those costs against each other when making a decision.

M. BROPHY: Okay. I think I understand that. And then, like, the portfolio, even before you have to make incremental decisions, what's the way that you evaluate that to assess whether it is cost-effective and a good baseline to compare to other decisions that come along?

A. MIKHAILA: So the base -- or the base gas supply plan, I guess, is just the -- the forecast cost of meeting the demands with the assets that we currently hold. And I think what you are asking for is incremental -- incremental costs are assessed against that base.

M. BROPHY: Yeah, so that was what we talked about a minute ago. But if you are using the baseline as the comparator to incremental decisions, how do you know the baseline is a good comparator, or if there is a better mix?

A. MIKHAILA: I think based on the assets that we hold to meet the demand, the optimization tool is the one that provides the cost-effective way of meeting the demands with the assets we hold. In a -- in an environment where we might have multiple options available to us to, you know, change the portfolio, they might be assessed differently. But in the current environment where transportation is scarce, the assets that we do hold are generally the only ones that are available to meet those demands, and so we don't have options to assess the base cost against.

M. BROPHY: Okay. Okay. And that links, then, to the earlier question about the asset management plan addendum that linked to some transmission projects, because then the new projects that open up new supply from a transmission perspective, and I guess you then assess that, you know, using a -- using a whole methodology that we don't need to get into here so -- okay. I think that is -- that is great. So I think that is all my questions. Thank you.

I. RICHLER: Thank you, Mr. Brophy.

We are a little bit ahead of schedule, which is great. My suggestion would be that we call it a day, come back tomorrow. We should still be able to finish up before lunchtime tomorrow. Unless there is any strong objections to that approach, let's -- let's adjourn, and see you all tomorrow morning at 9:30. Thank you.

--- Whereupon the proceeding adjourned at 3:59 p.m.