COMMISSION OF INQUIRY
RESPECTING THE MUSKRAT FALLS PROJECT

Transcript | Phase 3	Volume 3

Commissioner: Honourable Justice Richard LeBlanc

Thursday 18 July 2019

CLERK (Mulrooney): All rise.

This Commission of Inquiry is now open.

The Honourable Justice Richard LeBlanc presiding as Commissioner.

Please be seated.

THE COMMISSIONER: All right, good morning.

Just give me one minute.

All right. You remain under affirmation at this time.

And, Mr. Simmons, when you're ready.

MR. SIMMONS: Okay. Thank you very much, Commissioner.

And good morning, Mr. Colaiacovo. We had left off yesterday – I had some questions about intergenerational equity and I have one more, actually, along that line.

And if we can go, please, to your presentation, which is Exhibit P-04464, please, Madam Clerk? And it's slide 77. I am not sure which tab that is, but it's in your book as well.

THE COMMISSIONER: (Inaudible.)

MR. SIMMONS: It'll appear on your screen.

MR. COLAIACOVO: Mm-hmm.

MR. SIMMONS: Page 77, please.

THE COMMISSIONER: It's actually tab 2.

CLERK: Page 77?

MR. SIMMONS: Seventy-seven, yes.

MR. COLAIACOVO: Of the report?

MR. SIMMONS: Oh, I'm sorry. Um.

CLERK: Must be the other one.

MR. SIMMONS: 04464 – I've got the wrong reference here.

THE COMMISSIONER: Okay, 04445?

CLERK: (Inaudible.)

MR. SIMMONS: Just one moment. Fifty-five – slide 55, please.

CLERK: Good?

MR. SIMMONS: Right. So this was the slide where you'd split the – divided the cohorts into three different periods and you'd identified where intergenerational equities were. We'd already talked about, I think, the period from 2020 to 2041 yesterday when we talked about cost of service and the arrangements under the Power Purchase Agreement.

And, so the only other point I wanted to make here was that after 2041, you've got a period there for 2041 to 2070 when there is a change because of the expiry of the contract for the Upper Churchill plant. Correct?

MR. COLAIACOVO: Correct.

MR. SIMMONS: And the only point I just wanted to confirm there was that any intergenerational effects as a result of that are not tied in any way to the arrangements made for the Muskrat Falls Project, but are solely related back to the contract for the Upper Churchill plant that was put in place in 1969.

MR. COLAIACOVO: That's correct, yeah.

MR. SIMMONS: Okay.

MR. COLAIACOVO: My point was that the – there is an effect on the future of the Churchill Falls generating facility and the arrangements that could be made in 2041 because Muskrat Falls had been built –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – and my argument was that since ratepayers have contributed to Muskrat Falls, there is an argument to be made that they should benefit from the new arrangements of Churchill Falls, even though as of today, currently, there is no legal or contractual –

MR. SIMMONS: Ah –

MR. COLAIACOVO: – entitlement to that.

MR. SIMMONS: – I see. So this comes back to your analysis of the costs and benefits to the ratepayers who are paying for the Muskrat Falls Project and it ties to your – the argument you've made that there is a benefit that the, I guess, the province receives when it comes time to renegotiate the terms of what happens to Upper Churchill power, and that benefit has been derived from the fact that the Muskrat Falls Project and its transmission link to the United States has been developed.

MR. COLAIACOVO: That's correct.

MR. SIMMONS: I see. So, in order to balance that intergenerational equity, what kind of adjustment would have to be made to the benefits and costs for the ratepayers during the time period in 2020 to 2041?

MR. COLAIACOVO: So, two things. First, I think there has to be – or there could be a recognition of the value – the strategic value to Churchill Falls that Muskrat Falls has created.

MR. SIMMONS: Yes.

MR. COLAIACOVO: Secondly, that because that value was created by Muskrat Falls, and Muskrat Falls was principally being paid for by ratepayer –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – payments that ratepayers should participate in some level of benefit from Churchill Falls.

MR. SIMMONS: So your argument is: During the time period starting in 2020 up to 2041, those ratepayers in that time period should get some benefit out of the value that's going to come after 2041.

MR. COLAIACOVO: That's right.

MR. SIMMONS: So how do you do that?

MR. COLAIACOVO: Effectively, what you do is you finance it. What you do is you can effectively subsidize ratepayers for 20 years –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – by debt financing and then paying those costs after 2041, once the revenue stream has been created from Churchill Falls.

MR. SIMMONS: Okay.

MR. COLAIACOVO: The challenges with that are many and varied –

MR. SIMMONS: Yes.

MR. COLAIACOVO: – because you don't know how much revenue you're actually gonna get from Churchill Falls after 2041.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: So, there's a question of estimation and conservatism and, you know, how much of that benefit is it fair to actually transfer.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: There's also a cost because deficit – debt financing entails interest.

MR. SIMMONS: Right.

MR. COLAIACOVO: So, there's only so much that you can do, but some recognition of the ratepayer role in Churchill Falls and subsequently, at – sorry, in Muskrat Falls –

MR. SIMMONS: Mmm.

MR. COLAIACOVO: – and subsequently, Churchill Falls, I think is important. And then, some attempt to rebalance –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – the – those – between those generations, I think would be –

MR. SIMMONS: Yeah.

MR. COLAIACOVO: – appropriate.

MR. SIMMONS: So exactly how you do it may be something that would require a lot of work to find the right way and the right balance, but your proposition is that there is something that can be done, and it would be the right thing to do, I take it?

MR. COLAIACOVO: That's my point –

MR. SIMMONS: Okay.

MR. COLAIACOVO: – yes.

MR. SIMMONS: So the effect of that then would be to reduce the cost to the ratepayer of the Muskrat Falls Project during the first 50 years of the project?

MR. COLAIACOVO: Well, in particular, I think that the critical target period is the first 20 years.

MR. SIMMONS: Yes.

MR. COLAIACOVO: 'Cause that's when the highest burden is –

MR. SIMMONS: Right.

MR. COLAIACOVO: – going to be felt.

MR. SIMMONS: So the effect then of what you're proposing as a fairness measure would be to reduce the cost to the ratepayer – particularly during the first 20 years of the Muskrat Falls Project – to reduce the amount that they are paying for that?

MR. COLAIACOVO: That's right.

MR. SIMMONS: Right. And if we were to say that all this had been recognized at the time the project was sanctioned and the arrangements were put in place for financing and all this was done, would the effect of that then have been to increase the preference of the Interconnected case over the Isolated case? Because this concept of transferring fairness would only apply to the Interconnected case, not to the Isolated case, correct?

MR. COLAIACOVO: Sorry? That –

MR. SIMMONS: This would – this concept of what we're talking about, of the creation of value from the Muskrat Falls Project that should be recognized, this only applies to the Interconnected case, not to the Isolated –

MR. COLAIACOVO: That's correct.

MR. SIMMONS: – case.

MR. COLAIACOVO: Absolutely.

MR. SIMMONS: So if what you're suggesting as a fairness exercise had been implemented at time of sanction, am I correct that the result would've been that it would have increased the preference for the Interconnected case over the Isolated case?

MR. COLAIACOVO: Oh, I think that's true.

MR. SIMMONS: Okay.

MR. COLAIACOVO: Yeah.

MR. SIMMONS: Now, the divisions you have in the time periods here, of course, the first we go to 2041 and then the next division you have is 2070. And 2070 is 50 years out, and that's when the Muskrat Falls Project is paid off.

MR. COLAIACOVO: Correct.

MR. SIMMONS: So you've told us that – and I think we've had other evidence to this effect – that large civil hydroelectric projects have much longer life. There's a little plant here in Petty Harbour, close by, that I think is 111 years old now, and it's still churning out 1.5 megawatts every –

MR. COLAIACOVO: Sure.

MR. SIMMONS: – year.

So the cumulative present worth analysis was done for 50 years – a long period of time compared to normally – but I think you've identified that that 50-year period seems to match the financing period, so it matches the payoff. So it – am I correct then that it assesses the cumulative present worth for the entire period in which the ratepayers bear the full cost of that plant?

MR. COLAIACOVO: That's correct.

MR. SIMMONS: Right. But at the end of that period, the plant will still have a considerable residual value. Is that correct as well?

MR. COLAIACOVO: It will have enormous residual value there.

MR. SIMMONS: Enormous residual value. Does – you've looked at the way the modelling was done. Did the modelling for the Interconnected case take into the account the residual value of the Muskrat Falls assets at the end of the 50 years?

MR. COLAIACOVO: No, it didn't.

MR. SIMMONS: Okay.

Is there a way to have done that?

MR. COLAIACOVO: Well, what you would've done – you could've done it a couple of different ways. From – well, from an investor's point of view, you calculate a residual value – estimated residual value for that point, but then you have to discount it 50 years back to the present. So – and I mentioned this yesterday, this is the challenge of discounting over long periods of time.

MR. SIMMONS: Right.

MR. COLAIACOVO: At any reasonable discount rate, 50 years is going to bring the value down to almost nothing.

MR. SIMMONS: It diminishes it quite a bit.

MR. COLAIACOVO: Right.

MR. SIMMONS: Yeah.

MR. COLAIACOVO: So even if, theoretically, 50 years from now that plant is worth $10 billion, when you take 50 years of discounting at 7 per cent whack, it makes it worth less than $1 billion.

MR. SIMMONS: Right.

MR. COLAIACOVO: Right? So –

MR. SIMMONS: Yeah. So that's the –

MR. COLAIACOVO: So in terms of –

MR. SIMMONS: Mmm.

MR. COLAIACOVO: – affecting the difference between plans, it actually isn't going to make that much of a difference on a present value basis.

MR. SIMMONS: Now, that's from the investor point of view, what about from the ratepayer point of view? Because I've heard you make the argument that the real discount rate that should be thought of from a ratepayer's point of view is less than the return to the – to an investor. Is that correct?

MR. COLAIACOVO: Well, no –

MR. SIMMONS: No.

MR. COLAIACOVO: – that was the social discount rate –

MR. SIMMONS: Okay.

MR. COLAIACOVO: – which is more of a public policy concept.

MR. SIMMONS: Okay.

MR. COLAIACOVO: So I think my point was that the CPW calculation was for 50 years.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: There are inherent limitations in looking at one time period only. You can and should consider shorter time periods and see how different cohorts of ratepayers are being treated, but it is also important to recognize what happens the day after the contract is completed.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: In this case, year 51, for example.

MR. SIMMONS: Mmm.

MR. COLAIACOVO: And in year 51 of the Interconnected Island case, Muskrat Falls will have been fully amortized.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: It will have been – you know, paid off all of its debt obligations. It will have a low operating cost, and it will be able to provide power to ratepayers at relatively low cost.

MR. SIMMONS: Right.

MR. COLAIACOVO: In the Isolated Island case, no such benefit occurs, right? So it is an argument in favour of the Interconnected –

MR. SIMMONS: Yes.

MR. COLAIACOVO: – Island case.

MR. SIMMONS: Yes.

MR. COLAIACOVO: And an examination of what occurs in year 51, I think, is relevant when you're comparing one case to the other.

MR. SIMMONS: Yeah.

So it's – and it's an advantage of the Interconnected case that is not explicitly recognized in the CPW –

MR. COLAIACOVO: Yeah.

MR. SIMMONS: – numbers from the calculations.

MR. COLAIACOVO: No.

MR. SIMMONS: Right.

MR. COLAIACOVO: It's not.

MR. SIMMONS: Now, so you've – at the outset of your presentation you said that all this modelling is just tools. And they're tools that feed ultimately into a judgment that someone is going to make about whether to do a project or not.

MR. COLAIACOVO: That's correct.

MR. SIMMONS: So if it's hard to factor something like that into the CPW using the tool, is it at the judgment – exercise of judgment stage that those sorts of factors are to be taken into account?

MR. COLAIACOVO: Yeah, absolutely.

MR. SIMMONS: Mmm.

MR. COLAIACOVO: I mean, as I pointed out, not everything can be taken into account in a financial model.

MR. SIMMONS: Mmm.

MR. COLAIACOVO: So other forms of analysis are required, supplementary information is required and all of that has to form part of the judgment.

MR. SIMMONS: Yes, okay.

The – you'd explained yesterday that the CPW was a form of net present value. It was just a means of discounting a stream of cost and revenue that goes off into the future down to our present day. And we've heard other evidence to the effect that that's for the purpose of trying to compare different options on as equivalent a basis as possible because the Isolated plan plays out quite differently than the Interconnected plan does.

And we've also talked about, as you've just did, that shorter periods are often used rather than a full 50. And I believe you said yesterday that one of the issues of looking at 50 years, of course, is it gets harder and harder and harder to make reliable assumptions about what's going to happen with a whole range of different variables into the future.

Have you – I'm summarizing that correctly, I think?

MR. COLAIACOVO: That's fair.

MR. SIMMONS: So a feature of – or of discounting, whether you call it net present value or cumulative present worth, is it that year by year by year less weight is given to the costs and benefits? So, for example, the cost and benefits in year one have greater weight in the number, the CPW number, than they do from year two, which has greater weight than year three, which has greater weight than year four.

MR. COLAIACOVO: That's true.

MR. SIMMONS: And that continues on out. So do we reach a point in that 50-year time frame where we've captured most of the value of the CPW and what happens after that contributes relatively little weight to the actual assessments?

MR. COLAIACOVO: The effect of discounting is – it makes – it gives representation to the fact that events far in the future –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – are not that important to people today. Those events in the future may be very important to the people at the time –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – but they're not important to people today. And that's, in effect, what discounting does, what it represents, right? They're – events in the future are much less knowable, much less reliable –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – and much less important to us today.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: So, discounting puts more emphasis on near-term possibilities than it does on far-future possibilities.

MR. SIMMONS: Right.

MR. COLAIACOVO: It's a diminishment over time; it never goes to zero –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – but it is a diminishment over time.

MR. SIMMONS: Right.

So in a sense then, the process of using discounting for evaluating the two options matches – the weighting and the discounting matches the increasing unreliability of the assumptions that you've made as time – as you look farther into the future

MR. COLAIACOVO: That's correct.

MR. SIMMONS: Right.

MR. COLAIACOVO: And the theory is that the higher the discount – a higher discount rate includes a larger premium for risk.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: So the greater the uncertainty, the higher your discount rate should be.

MR. SIMMONS: Yes.

MR. COLAIACOVO: In which case it puts more – a higher discount rate, a higher risk, puts more and more emphasis on near-term impacts.

MR. SIMMONS: Right.

So if were looking at the price of oil and we say we're reasonably confident what the price of oil will be next year, and make some sensible guesses about the general way it's going to go for the next five years, and after that it gets less and less reliable, the fact that we have a discount rate at a particular level takes into account that – or it helps us balance the relative reliability of what we know what the price of oil might be next year versus what it might be in twenty years' time.

MR. COLAIACOVO: So there's – when you're doing financial modelling and you have multiple different variables –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – with a degree of uncertainty around them, you can either include in your discount rate a sufficiently high-risk component –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – to take into account all of the variability and all of the risks. Or, alternatively, you can isolate each variable and say, okay, this variable has a high range and a low range and I'm going to run different scenarios at high and low –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – right, and see what that does to your outcome.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: In a model like the CPW model, where Nalcor chose to use its cost of capital, that cost of capital doesn't take into account, for example, the risk variability in fuel. So it's appropriate to run a high case and a low case on fuel because the cost of capital is not explicitly trying to take into account the variability of fuel. It's drawn from the regulated cost of equity and the current cost of long-term debt in the market for utilities.

Fuel is a separate set of risks, so it's not fair to say that the discount rate that was used in the modelling takes into account variability around fuel or variability around load or any of those other variables that were being addressed. The discount rate does include the variability of inflation.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: It does include the variability of the credit markets because those are explicitly taken into account in the weighted average cost of capital. So some of the risks are captured and some are not.

MR. SIMMONS: Okay, right.

Okay, so the discount – the use of a discount rate and the higher the discount rate is takes into account some of the risks associated with unreliability of prediction of what's going to happen in the future. And what you're telling us is that, in addition to that, some form of modelling has to be done to more explicitly look at variability in some of these assumptions.

MR. COLAIACOVO: That's right.

MR. SIMMONS: Okay? All right.

So that brings us, then, to the modelling. And I wanted to ask you some questions about what you've described for us as being the way you say the best modelling should be done for a decision of this sort. So let me run through what I understand you've said so far and I've got some questions so I can understand –

MR. COLAIACOVO: Sure.

MR. SIMMONS: – the practicality of it a little bit more.

So we've got – by 2011, when the reference was made to the Public Utilities Board, we have two development scenarios that are being examined: The Interconnected Option and the Isolated Option. If I understand correctly, for each scenario, you say that there are assumptions that have been made that are built into – well, into the CPW analysis.

And for those assumptions, there should be some exercise to identify – and there are many assumptions that go into it, but we need to identify the ones that have the potential to have the more significant impacts on the outcome.

MR. COLAIACOVO: That's correct.

MR. SIMMONS: You're nodding, so that would be right.

And then for those assumptions, you identify the reference number which is – I don't know if that's the most likely number or the median or the average or whatever it is, but it's the middle number. And then somehow you pick a low number and somehow you pick a high number, okay?

MR. COLAIACOVO: Lots of judgment involved in those –

MR. SIMMONS: And lots of –

MR. COLAIACOVO: – (inaudible), yes.

MR. SIMMONS: – judgment involved in that.

And then, once you have your list of how many assumptions you're going to use for variations in modelling, and you have referenced low and high for each of them, then you have to run a modelling – model a scenario for every single combination of all of those variables.

MR. COLAIACOVO: Depending on how many variables you're dealing with –

MR. SIMMONS: Right.

MR. COLAIACOVO: – it may be practical to run all of them.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: Computers do these things very quickly. If it's – if the number of variables is simply unmanageable, you could – if you had six variables and five different states, it's literally millions of combinations.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: And for that kind of a scenario, you use a Monte Carlo program. A Monto Carlo facility – a Monte Carlo program, it's a method of analysis that relies on random walks.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: So you run several thousand – a sample of several thousand different scenarios – or combinations of variables, instead of millions. But by running several thousand, it's a large enough sample that gives you the average – the outcomes that you would expect if you actually ran all of them. It's just a statistical probability exercise.

MR. SIMMONS: I'm just going to step back a little bit now to make sure I have the basics of this, and I'm not sure that I got the math right. But let's say we had two assumptions and you just said states, three states. So, low reference, high, each of those would be a state.

MR. COLAIACOVO: Right.

MR. SIMMONS: So two assumptions in three states, if you put those on a grid, you know, this grid –

MR. COLAIACOVO: Six boxes.

MR. SIMMONS: – three across the top here, across the bottom, you got nine boxes. So that's nine scenarios; three times three. Do I right –?

MR. COLAIACOVO: Two assumptions.

MR. SIMMONS: No, two times three, so that's six.

MR. COLAIACOVO: Two times three is six, yeah.

MR. SIMMONS: That's six scenarios.

MR. COLAIACOVO: Right.

MR. SIMMONS: So if you add then another assumption, you get the three assumptions, now you're up to –

MR. COLAIACOVO: Nine.

MR. SIMMONS: Up to nine and then it builds that way. So the more assumptions you add in, the greater the number of scenarios that you are going to have to run. Okay.

So – and maybe you've answered this question already, but the purpose for running all the scenarios, it seems to me that there's perhaps a couple of ways the output from running all those scenarios can be used. One is that it can be evaluated subjectively by the decision-maker or some intermediary who does some analysis for the decision-maker, who looks at it and says here's my analysis of what all this means.

But the other way is to take the outcome of all the scenarios and apply some further type of modelling to it, which would – like the Monto Carlo that you're talking about.

MR. COLAIACOVO: Right.

So there's typically two different ways –

MR. SIMMONS: Yes.

MR. COLAIACOVO: – that you can do it.

MR. SIMMONS: Yeah.

MR. COLAIACOVO: There's some different steps. So if you have three variables with three different states –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – each, it's three to the third, right? So it's actually 27 different possible combinations.

MR. SIMMONS: Yep.

MR. COLAIACOVO: Right? So you can analyze the – you take the – you run your model 27 times.

MR. SIMMONS: Mmm.

MR. COLAIACOVO: With the 27 different possible combinations of those three different variables, three states. The first thing you do is you take the average, so that you understand what the average outcome is amongst –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – all the 27.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: Second, you look for the highs and lows – what's the best scenario out of those 27, what's the worst scenario out of those 27 – to understand what the range of outcomes is that might – you might ultimately end up with.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: The next thing you look at is if you're comparing two different options, so you've run it 27 times for one option and 27 times –

MR. SIMMONS: Twenty-seven times for the other.

MR. COLAIACOVO: – for the other option, right?

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: So you're comparing the averages. You're comparing the highs and lows. Because you want to understand if one option – one option might have a higher high and a lower low.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: The other option, their high and low may be closer together. And so you get a sense of the range of variability for each option, right? Because the – variability is a proxy measurement for risk, right? So one option may be inherently riskier if the outcomes are more variable than the other option.

Another piece of analysis that you would do on the 27 outcomes is you would say, well, if I'm comparing the two different plans, in how many of those 27 cases is one plan better than the other? You might find that in 18 of the cases, one plan is superior and only in nine cases, the other plan is superior, right? So that's an important issue to unearth.

And then another step you can take is if you actually placed a probability on any of the different variables, the highs and lows. Like, for example, in some cases, you see these exercises run and – you know, oil price. If somebody gives you an oil price projection and says, there is a 50 per cent probability that oil prices are going to follow this reference curve, and there's a 25 per cent probability for the high case and a 25 per cent probability for the low case, you might similarly get a load projection that has the same kind of probability assigned to it. And you would get an export price projection that has the same kind of probability assigned to it. And then what you do is you literally multiply those probabilities and then you identify, of your 27 cases, which are the group that are more likely to happen, because they're central, they're closer to reference.

And so then you want to try and understand, in the more likely cases, which of the two plans is stronger. Because, remember, you identified that in 18 cases, one of them was better than the other. But are those the 18 unlikely cases or are they the 18 likely cases, right?

MR. SIMMONS: Okay.

MR. COLAIACOVO: And so you can make a more and more sophisticated, deeper analysis –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – if you've got the information available.

MR. SIMMONS: So several questions coming out of that. First, for the inputs, the assumptions that are inputs where we said there's a low and a reference and a high, there's an element of subjectivity on the part of whoever is making those predictions as to how high and how low and where the reference is.

MR. COLAIACOVO: Absolutely.

MR. SIMMONS: Right. So at some point, you're relying on someone's judgment to come up –

MR. COLAIACOVO: You're always relying on someone's judgment.

MR. SIMMONS: Okay. And if then – then from that point, we're relying on, again, to some extent judgment of knowledgeable people to identify which are the assumptions that have – that need to be modelled? Maybe (inaudible) –

MR. COLAIACOVO: Partly.

MR. SIMMONS: Okay.

MR. COLAIACOVO: Partly, because I think when you run your sensitivities – and that's the step before you start doing scenarios –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – so you prepare your financial model, and your financial model might have a dozen different variables in it, right? And you know, because you've been advised by professional forecasters, for each one of those different variables, that there's a certain range that you're dealing with. And so when you run a sensitivity, you say, well, what's the difference in my model outcome between the high case and low case for this particular variable?

MR. SIMMONS: So (inaudible).

MR. COLAIACOVO: And if it's a very small change, if it's less than a per cent or 2 per cent, then you wouldn't bother paying attention to that variable anymore, right? So –

MR. SIMMONS: So there's an element of objectivity because it's the output or the, of –

MR. COLAIACOVO: That's right.

MR. SIMMONS: – of the model run that tells you whether you changing this assumption has had a big impact or –

MR. COLAIACOVO: That's right.

MR. SIMMONS: – a small impact. So, okay.

But then you say also that you – you said, if you assign probabilities. Now, why wouldn't it be necessary to assign probability? Why would you not assign probabilities, and what difference does it make whether you assign probabilities or not?

MR. COLAIACOVO: Yeah. So if you assign probabilities, it allows you to focus on the most likely cases, quote, unquote.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: That assumes that you can assign those probabilities with some – there's actually some underlying credibility in the assignation of those probabilities.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: In many of these instances, people just say: Well, you know, the reference case is a 50 per cent likelihood. Why is it a 50 per cent likelihood? I mean, you defer to the judgment of professional forecasters.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: That's their job. They do it every day. And so that's what you do, you defer to them. But assigning probabilities to high and low forecasts is notoriously difficult.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: And so it's – whether you assign those probabilities or not, it's, I think, one of the more minor aspects of the exercise. The – I think the more important issue is to actually get a sense of, through sensitivities, which variables are more important and then running scenarios on all of the important variables.

MR. SIMMONS: Okay.

So, on the probabilities then, it sounds to me like if you choose to incorporate the probability of different scenarios in your model, there is, again, some element of subjectivity on the part of some knowledgeable person who's going to assign a probability.

MR. COLAIACOVO: That's right.

MR. SIMMONS: And if you can't get a reliable – enough information to allow you to assign probabilities, then you ignore it and just proceed without assigning –

MR. COLAIACOVO: That's right.

MR. SIMMONS: – probabilities. Even though there may be greater – there may, in fact, be greater probabilities that some scenarios will occur than others.

MR. COLAIACOVO: Right.

MR. SIMMONS: So that – this kind of introduces an element, to my mind, an element of – not so much error, but an element of variability in the outcome of the modelling exercise.

MR. COLAIACOVO: Yeah, yeah, absolutely.

MR. SIMMONS: Yeah. Okay.

And as for who would assess the probabilities, we'd be looking to the experts who are supplying the information on which we base the assumptions, as opposed to the people doing the modelling.

MR. COLAIACOVO: That's right.

MR. SIMMONS: Okay.

So once you've selected – once you've identified the assumptions, identified the high and low ranges, maybe applied probabilities, run a bunch of scenarios, now you have to somehow digest and analyze that evidence. You said you could do a Monte Carlo-type analysis.

MR. COLAIACOVO: Typically, Monte Carlo analysis is required only if there are many variables –

MR. SIMMONS: Many variables.

MR. COLAIACOVO: – with many (inaudible).

MR. SIMMONS: Right.

So if there's not – and it sounds like we're still dealing with, I don't know, 80 to 100 –

MR. COLAIACOVO: Mm-hmm.

MR. SIMMONS: – scenarios before you get to a Monte Carlo.

So what do the people doing – who are conducting this exercise then do with all those scenarios? Do they just present all the results to the decision-maker and the decision-maker looks at them and makes their own subjective evaluation? Or is there some sort of recognized process by which that information is analyzed for use by the decision-maker who's going to exercise the judgment.

MR. COLAIACOVO: No, I think the – I mean, you know, the – it's some of the different metrics that I just – I pointed out.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: The average of the different scenarios, the high and lows of the scenarios, the number of scenarios that favour one option versus the other option.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: Critically – an understanding of what the highs and lows mean for different stakeholders in each case. So, for example, you can be working with a problem where one option has a majority of scenarios where one option is better. But there are three scenarios in which that option leads to bankruptcy, right? The other option is inferior in many scenarios but there is no scenario in which the other option ever leads to bankruptcy.

So that presents an interesting judgment call. Do you want to go with the scenario that on average gives you better outcomes but risks bankruptcy? Or do you go with a scenario that on average gives you the worst outcomes but never risks bankruptcy? And so that's where judgment comes in. And ultimately the decision-maker has to make that choice, but they should know what those risks and options are before they make it.

MR. SIMMONS: Right.

Now – and you've made the observation, of course, that what was done in the case of the Muskrat Falls Project with the CPW analysis and the way the cases were run, produced a number – you would say limited number of sensitivities. But in your view, running more cases and doing more of the analysis, you just described, would have added value –

MR. COLAIACOVO: Yes.

MR. SIMMONS: – to the process. Okay.

Now – so where do we look to find a – some sort of recognized description or a manual or a publication or a book or an authority that would tell us how to do everything that you've just described, aside from calling you up and getting you to do it for us.

MR. COLAIACOVO: So Monte Carlo models (inaudible) –

MR. SIMMONS: But it's more than Monte Carlo models (inaudible) describing there.

MR. COLAIACOVO: No, no, I know. But Monte Carlo models were developed as a substitute for the kind of analysis that I'm talking about where there are too many cases –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – right, to calculate, right?

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: The problem has been, kind of, long recognized in financial economics and in decision-making theory. Monte Carlo models were invented 40 years ago, 50 years ago.

MR. SIMMONS: Mmm.

MR. COLAIACOVO: So, the history of this kind of analysis goes back a long way. The application –

MR. SIMMONS: (Inaudible.)

MR. COLAIACOVO: – to this kind of – of this kind analysis to electricity system planning, I think, is somewhat more recent. But, nonetheless, if you look at electricity system planning work, even in Canada – and there's more in the United Stated that's been done over the last 40 years or so – there's a higher and higher degree of decision-making analysis sophistication that has been growing over time, particularly when, for example, a jurisdiction is deciding to build a nuclear plant for – you know, you go back to the 60s and 70s when nuclear plants were being built across North America, there were some very large and sophisticated decision-making processes around whether they should go ahead or not.

So, can I point to a book that exists –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – that says this is how you do it? No, I can't.

MR. SIMMONS: Mmm.

MR. COLAIACOVO: But in the electricity utility business where there have been very large infrastructure investments – not just of hydroelectric plants, but other kinds of system assets – there have been sophisticated decision-making processes.

MR. SIMMONS: So, with something else we've looked into in this Inquiry has been the bid estimating, capital estimating, you know, capital cost estimating. And we've seen, for example, that there are recognized industry, I'll say, authorities like AACE – I don't know if you're familiar with that, I can't give you the exact name of the acronym – but they provide guidance, they have published standards where panels of recognized people have contributed, they've spent time to put it together, and they're – it's a, you know, number of pages that give some guidance to someone about how to do a particular type of estimating and about how to analyze risk, about – in estimating.

And in addition to that, we've also heard that there are practices, varying views, consultants and experts who bring expertise into how they do all those things. So, it seems to be a combination of – there's someone you – where you would go and look it up in a book, and also you rely on what experts can bring you when you go and find them.

It sounds to me like the type of process you are describing for doing the financial modelling, is far more that latter and much less the former, where I – there's no standard-setting authority –

MR. COLAIACOVO: No.

MR. SIMMONS: – or reference authority that's gonna give us any kind of written guidance, and the people who are gonna make the decision are going to have to go out into the industry and find the people who can give them the advice on how to do this.

MR. COLAIACOVO: I think there are – you're right that there are no standards.

MR. SIMMONS: Mmm. There's none referenced in your report, correct?

MR. COLAIACOVO: No, there's no – there's no industry association or –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – of course, you know, standard-setting body.

MR. SIMMONS: Is there a standard text?

MR. COLAIACOVO: There are finance texts and there are decision-making texts and – but this is – it's a matter of practice.

MR. SIMMONS: Mmm. Right.

MR. COLAIACOVO: Okay?

MR. SIMMONS: Like in the public utilities realm, there's sort of – several books that are kind of the Bible about how to do public utilities regulations. There's nothing equivalent for the type of process that you're – decision-making process that you're advising us on here.

MR. COLAIACOVO: No.

MR. SIMMONS: Okay.

MR. COLAIACOVO: Having said that, you know, Manitoba Hydro followed this process in 2013 for their –

MR. SIMMONS: Right.

MR. COLAIACOVO: – their NFAT. In Ontario, the Ontario Power Authority, when it was designing its system, did multiple volumes of complex research and analysis in 2005 when it was deciding on its supply mix. The – you know, that the idea of using portfolio theory and risk analysis is not uncommon in electricity system planning and hasn't been uncommon for quite some time. And that's really what this is all about.

MR. SIMMONS: Okay.

So, your fairly specific description of generating the multiple scenarios and how you analyze them, would that be an application of the kind of principles that you're describing there, or is that something that is – has been very specifically applied, in your experience, in situations other than the Manitoba Hydro one that you had spoken of?

MR. COLAIACOVO: Oh, it's both.

MR. SIMMONS: Mmm.

MR. COLAIACOVO: I mean, the – from a financial modelling perspective, identifying sensitivities and running scenarios is absolutely standard.

MR. SIMMONS: Yes.

MR. COLAIACOVO: That's standard financial modelling practice.

MR. SIMMONS: Mmm. Right.

MR. COLAIACOVO: So, first you run the sensitivities, then you run scenarios.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: There's no question about that. Applying that to large infrastructure choices is a matter of application. It's taking a standard financial modelling technique and applying it to a particular situation.

MR. SIMMONS: Okay.

So you've described your experience with Manitoba Hydro which you've said was in the – was in 2013?

MR. COLAIACOVO: Yeah.

MR. SIMMONS: Okay.

And, it's already in Mr. Smith's questions, he already pointed out that in 2011, with the referral to the Public Utilities Board here, the question of examining and testing whether the Interconnected Option was least coast as compared to Isolated, was squarely in the hands of the Public Utilities Board, which is an independent regulator from Nalcor. And they independently retained Manitoba Hydro International – affiliated with Manitoba Hydro but a different organization – who came in to look at this process and contributed some sensitivities.

And when we look at the work that they – Nalcor's work that they analyzed and what they contributed, it doesn't seem to go nearly as far as what you're describing. So –

MR. COLAIACOVO: Which I found very curious. But I would point out that the sensitivities were done by Nalcor –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – before Manitoba Hydro –

MR. SIMMONS: Yes.

MR. COLAIACOVO: – International became involved.

MR. SIMMONS: Yes.

MR. COLAIACOVO: So – because in its initial report November of 2011, the sensitivities were already included in that report from Nalcor. So Nalcor did the sensitivities –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – in the financial model.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: They just didn't take the next step of then running scenarios –

MR. SIMMONS: Right.

MR. COLAIACOVO: – that involved combinations of those sensitivities.

MR. SIMMONS: Now – and this is where there's – there seems to be a gap of some sort, where the independent regulator retains an expert who is expected to bring the kind of expertise to do critical analysis of the way this decision has been done and they don't suggest that this scenario approach that you've described is to be used. I mean, what else is the PUB to do in that case, if that's – if they're not getting that advice?

MR. COLAIACOVO: I can't answer that question.

MR. SIMMONS: Mmm.

MR. COLAIACOVO: I don't know why they wouldn't have recommended that.

I think it is interesting that in the regulatory process, intervenors and the regulator itself requested scenarios be run. They requested, for example, that a combination of a low load and low fuel in –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – some particular format be run through the Strategist model. And Nalcor did so –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – and replied and said, okay, here's the outcome – here's the result of running those – the combination of those two different variables.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: Why the next step was not taken – instead of just running two or three of those combinations, why not run the full set of combinations –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – why was that not done at the time, I can't answer that question. It should have been done.

MR. SIMMONS: Right. Okay.

And you say it should have been done based on the evidence you've given and your analysis of what would be a better way to do –

MR. COLAIACOVO: That's correct.

MR. SIMMONS: – it. Would you say it rises to the level where it was an accepted industry – utility industry practice for decision-making that this is the way it is done – to run all these multiple scenarios – or do you have enough experience across it to be able to say whether that's the case or not?

MR. COLAIACOVO: So system planning, as an exercise, is relatively recent.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: The tradition – the traditional utility model which was followed across most of North America from approximately 1920 'til 1990 –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – was monopoly utilities in each province of Canada or State in the United States or a particular jurisdiction. And the utility would occasionally build a new coal- or oil-fired facility and would string, you know, poles and wires to deliver electricity to customers.

The whole thing was quite sleepy. And it was a fairly standard model. Beginning in the 1990s with the development of combustion – gas combustion turbines and a movement to deregulate parts of the industry and separate transmission from distribution and generation, an enormous amount of development began across the North American utility industry.

Regulations in a regimes really have gone through massive change in the last 30 years. Plus there've been an enormous amount of technological developments around conservation and demand management and renewable energy. So now there are far more options than there used to be to manage an electricity system. And as a result electricity system planning has become a discipline.

The first system plan that actually is worthy of that name I think that I can recall in Canada is the 1989 system plan in Ontario that was proposed and never adopted. British Colombia did some very early work in system planning in the late 90s and early 2000s –

MR. SIMMONS: Can I interrupt for a second? When you're talking about system plans, are you talking about something we may have heard of as described as an integrated resource plan?

MR. COLAIACOVO: That's right.

MR. SIMMONS: Okay.

MR. COLAIACOVO: Integrated resource plans.

MR. SIMMONS: As opposed to the conventional system planning that's –

MR. COLAIACOVO: That's right.

MR. SIMMONS: – done by an operator of the –

MR. COLAIACOVO: That's right.

MR. SIMMONS: – (inaudible).

MR. COLAIACOVO: In –

MR. SIMMONS: Okay.

MR. COLAIACOVO: – integrated resource planning. It –

MR. SIMMONS: So that's what you're talking about.

MR. COLAIACOVO: – is what I'm talking about.

MR. SIMMONS: Yeah.

MR. COLAIACOVO: And integrated resource planning really has arisen because now there is proliferation of technologies and a proliferation –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – of options.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: And when you have a proliferation of technologies and options you have make choices.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: How do you make choices? You have to gather data and do analysis and do financial modelling to make choices, right? And so, integrated resource planning is where you find the use of these tools. It's where you find portfolio theory. It's where –

MR. SIMMONS: Oh, okay.

MR. COLAIACOVO: – you find financial analysis.

MR. SIMMONS: Right.

MR. COLAIACOVO: It's all in integrated resource planning.

MR. SIMMONS: Right.

And we've heard evidence that integrated resource planning, that model of planning does require a greater application of utilities resources than the more conventional approach. In other words it's more costly, administratively costly to do integrated resource planning. That's something that we have heard as one reason, which is not to say that that's a reason not to do it, but it's a consideration, I'm going to suggest, given the size of the market, because we are in a small province with a small population. Is that a – and in your view does that have any bearing on what kind of resources and what kind of effort you can put into achieving that sort of level of planning?

MR. COLAIACOVO: I think integrated resource planning is – it's the same as any other capital cost. It's an – it's an upfront expenditure that you make in order to ensure that your long-term investments are as efficient as possible.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: Right? So because there are many options today in terms of how to manage an electricity system, electricity – investing in electricity resource planning is how you make the best choices, and how you avoid pitfalls. If you don't invest in integrated resource planning, then what you're at risk of is being inefficient and over time delivering a poorer, more costly system to customers.

MR. SIMMONS: Okay.

Okay, so we've been talking about, kind of, the utility side of the modelling here now, and I want to move on a little bit to some of the other factors that you've talked about just briefly. And if we can go back to the presentation, please, at 04464, Madam Clerk. And this time I think we're going to page 26.

Okay, so I've brought you to this page just for the quote from Minister Kennedy, from when the sanction of the project was announced in 2012, you went to this yesterday. And he, in addition to the – meeting the energy needs and stabilizing rates, he also referred to economic, employment and social benefits. I think these are some of things that you identified as being benefits that fell on the taxpayer side of the ledger, for which ratepayers were bearing some of the risk but not some of the benefit.

MR. COLAIACOVO: That's correct.

MR. SIMMONS: Now – but my question here, though, is do you see these sorts of benefits as being ones that also should be modelled; and, if so, whose role in this mix would it be to model those benefits so that the value of them can be taken into account in the judgment call about whether to do the project?

MR. COLAIACOVO: Yeah, and those typically are modelled.

MR. SIMMONS: Are?

MR. COLAIACOVO: They typically are modelled – at least to a reasonable degree. I mean, there's a tremendous amount of uncertainty, for example, and economic multiplier effects.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: But they typically are modelled, because government does care about those things. And they are relevant in the decision-making process.

Now, I know from the record of exhibits that are available that there was some modelling done internal to the government about exactly those issues.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: I didn't spend time reviewing, you know, that modelling, because it was kind of outside of scope. But the – some work was done, and the government was aware of that work. It was presented in Cabinet documents and so on.

MR. SIMMONS: So the outcome of modelling those types of benefits, that wouldn't be included in the CPW analysis comparing –

MR. COLAIACOVO: No.

MR. SIMMONS: – the two options, correct?

MR. COLAIACOVO: No, it would not.

MR. SIMMONS: So that is a separate piece. Those – the results of those models are separate inputs that go to the decision maker, in addition to the question of which has the least utility-based cost –

MR. COLAIACOVO: That's correct.

MR. SIMMONS: – that goes to the decision maker. Okay.

Okay, some – just a couple questions about your evidence concerning the potential for purchase of power from Hydro-Québec prior to 2041, and the relationship to the negotiations that would have to take place for what happens after the expiry of the current Upper Churchill project in 2041.

So you've – I mean, you've made the argument quite strongly that the development of the Muskrat Falls Project and the transmission has value that will improve the province's negotiating position for what happens after 2041. And I may have asked you this already, but that value has not been incorporated into the CPW analysis in any way –

MR. COLAIACOVO: No it has not.

MR. SIMMONS: – has it? No. Okay.

And in addition to that, in your review of the other materials that fed into the decision making in addition to the CPW analysis, you didn't see that explicitly recognized as a value for the project either?

MR. COLAIACOVO: No.

MR. SIMMONS: So it doesn't appear to have been explicitly factored in. If it were included in the decision making and factored in, could it have had any effect other than to favour the Interconnected case over the Isolated case?

MR. COLAIACOVO: Oh no, it definitely favours the Interconnected case. There's no question about that.

MR. SIMMONS: Okay.

Now, I want to go to your report, please, P-04445. And we'll go to page 34. This is just a reference for something that I think you actually said in your evidence eventually yesterday. So beginning at line 4, there's a paragraph here where you make the case that if negotiations were entered into with Hydro-Québec to purchase power in order to bridge the Island's power needs, 2041, it's inevitable that – because of Hydro-Québec's interests – that "would morph into" – the term used in the report – "would morph into" a negotiation about what happens after 2041.

MR. COLAIACOVO: I think that's correct.

MR. SIMMONS: Okay.

And you've also told us about the value of the development of the Muskrat Falls Project to the province in those post-2041 negotiations. So this is just a point logically connecting those things. It would seem to me that if there were to be negotiations for purchase of power to 2041, they would have to happen before a final decision is made on whether or not to build the Muskrat Falls Project. There'd –

MR. COLAIACOVO: That's correct.

MR. SIMMONS: – be no point otherwise.

MR. COLAIACOVO: Yes.

MR. SIMMONS: And if those negotiations then progressed to include what happens after 2041, inevitably, the province would be in a disadvantaged position because they do not have the benefit of proving the transmission route to the United States.

MR. COLAIACOVO: That's correct.

MR. SIMMONS: Right.

Which would – and although you haven't made that connection here, that would seem to be – to me, to be another reason why it would have been disadvantageous to try to purchase that power from Quebec.

MR. COLAIACOVO: That's correct.

MR. SIMMONS: Okay.

Back to the presentation, please, P-04464, slide 7.

It's just a few questions concerning fairness again and kind of leading into some of the mitigation questions.

So this is where you've presented the two tests that can be applied for the fairness opinion. The first being whether the proposed project is at least as financially favourable as the available alternatives, which is slightly different than the PUB question of whether it's the least-cost option; you're saying it's got to be just as good, not necessarily better.

MR. COLAIACOVO: That's correct.

MR. SIMMONS: Right.

That test sounds like a pass/fail.

MR. COLAIACOVO: Pretty much.

MR. SIMMONS: Okay.

MR. COLAIACOVO: The problem with it – so, in some contexts, because this is a – typically these tests are applied to transactions.

MR. SIMMONS: Mmm.

MR. COLAIACOVO: We do mergers and acquisition transactions every day and we provide opinions on valuation and fairness opinions on transactions.

And so the typical question is a company has received an offer – someone wishes to buy the company and the board of directors is looking at that offer. And the question is, is it a fair offer? Well the basic problem that the board has is –

MR. SIMMONS: Mmm.

MR. COLAIACOVO: – could we sell the company to someone else for more money, which would benefit our shareholders, right? So that's the simple test, right? It's a yes-no question: Is there a higher price available from someone else?

MR. SIMMONS: Right.

MR. COLAIACOVO: And in that kind of circumstance, it is a pass-fail question, it is a yes-no question. If there is no other potential buyer who's willing to offer you a higher price, then this is the best price. But in a complicated situation like the one we're – you're dealing with when you're talking about system plans and choices between Interconnected versus Isolated –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – you're not dealing with a simple pass-fail because there's a high degree of uncertainty. There are all those probabilities and cases, some of which favour one option and some of which favour another option. So coming to the conclusion, is it at least as financially favourable, becomes a much more nuanced issue.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: It's not a simple pass-fail question at that point.

MR. SIMMONS: Right.

So because the final decision on whether to do this project was going to be one of the application of judgment – and this analysis is an input into it – is it conceivable that the Interconnected case could have what I'll call failed this test by being analyzed as not financially the most favourable but still, in the judgment of the decision-maker, be the project that was the right one to build?

MR. COLAIACOVO: Yeah, so now you get to a question of what was the decision – what was the basis for the decision, right?

MR. SIMMONS: Mmm.

MR. COLAIACOVO: If you ask the question: Which option was better – excuse me – better for the province –

MR. SIMMONS: Yes.

MR. COLAIACOVO: – writ large.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: Well, the province's concerns are ratepayers, yes, but also taxpayers and the environment and local economic development and, you know, future prosperity in the province and best use of all of the province's assets and resources.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: And that is a multi-part – you know, multi-interest decision that you're then trying to make. On the other hand, if you narrowly ask the question which is better for ratepayers –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – then you're focusing on costs.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: And I think as I pointed out in the report, the question to the regulator was always very narrow: Which one is cheaper for ratepayers?

MR. SIMMONS: Yes.

MR. COLAIACOVO: There was no ambiguity in that.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: Which allows you, from a fairness-opinion perspective, to focus narrowly on, you know, that question which is still not easy to answer because of all the uncertainty involved.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: Right?

So identifying just ratepayers and saying is it fair to ratepayers, makes you focused on the cost issues and the risks around costs.

MR. SIMMONS: Okay.

MR. COLAIACOVO: If you ask the question: Is it fair for the province –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – is it desirable for the province –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – you get into a whole other decision tree.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: Right?

But I also think that was never terribly clear. The minister's announcement quite obviously points to jobs and economic –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – development and natural –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – resources and all those other things, right? But the justification for the project appeared to always be that it was going to be the cheapest for ratepayers.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: So there was a fuzziness in the communication around how the decision was made and why it was being made the way it was made.

MR. SIMMONS: Okay, thank you.

So the second part of the test for fairness opinion there is the one that looks at, I'll call it, the allocation of cost, benefits, risks and opportunities among stakeholders. And from your analysis looking – taking the narrow approach of saying, is this fair to ratepayers, you've expressed the view that because there are so many other benefits that accrue to taxpayers, to the province, that there's an element of unfairness to the ratepayers here.

So, first of all, the application of this part of the fairness opinion test doesn't strike me as being a pass-fail, it strikes me more as being an identification of an issue to be addressed somehow.

MR. COLAIACOVO: Yeah. It's – well, I think this is a recognition that given uncertainty, right –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – and you have a lot of uncertainty in this instance – I mean, you can't answer the question conclusively which is the most financially favourable, because it depends on future outcomes.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: And those future outcomes, the risks and opportunities of those future outcomes are going to be distributed by the project, in certain way, by the decisions and contracts and arrangements, right?

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: And so who – what is the allocation, what is the distribution of those risks and opportunities? And so you have to analyze that, right? And in the analysis, it turns out that ratepayers are bearing, you know, at least in the formulation of the decision in 2012 –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – because since then there have been government announcements that have changed things.

MR. SIMMONS: Sure.

MR. COLAIACOVO: But in 2012 ratepayers were bearing a substantial amount of risk with very little upside opportunity. And that was different from the government, the shareholders of Nalcor, who were guaranteed a return, right, and had upside opportunity but were not bearing the downside risk.

MR. SIMMONS: Okay.

So if in 2012 at the time of – before the sanction decision was made, if you'd been retained to do this sort of analysis then – and I know we're applying hindsight here, but let's put you back there and say the outcome of your fairness analysis would have been the same and you would have come to the same conclusion, that the ratepayers are bearing too much risk for too little benefit and the taxpayers are getting a big benefit for very little risk, then if that were to be addressed then, it would have required some kind of change to the project structure, financing, commercial, whatever in order to reallocate some of those either risks to the taxpayer or benefits to the ratepayer – and you're nodding –

MR. COLAIACOVO: That's right.

MR. SIMMONS: – so that's – on a high level that's what would have had to be done.

MR. COLAIACOVO: That's right.

MR. SIMMONS: Now, had that been done at the time, is that something else that would have favoured – then favoured the Interconnected case –

MR. COLAIACOVO: Yes.

MR. SIMMONS: – without making any change to Isolated?

MR. COLAIACOVO: Absolutely. Like, as I made the point in both my report and presentation, in a majority of the scenarios –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – the Interconnected Island plan was favoured.

MR. SIMMONS: Yeah.

MR. COLAIACOVO: There was no question that the ancillary benefits of the two options –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – the jobs and the environmental impacts and the future of Churchill Falls, which was a big consideration –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – all of those things favour the Interconnected plan. The significant weakness was the allocation of risks and benefits.

MR. SIMMONS: So we know now that the province has been – has a plan for rate mitigation which, having heard your evidence and read your report, sounds like what it really is, is some reallocation of those benefits – to move benefits from the taxpayer pool over to the ratepayer pool to redress a fairness issue that perhaps could have been identified at the time of sanction.

MR. COLAIACOVO: That's correct.

MR. SIMMONS: Yeah.

And we're at a point where the ratepayers haven't started to pay yet for the project 'cause it's not finished.

MR. COLAIACOVO: Right.

MR. SIMMONS: So if it's possible to implement a plan along the lines of what they said or to do something to redress that balance at this point, would it have made any difference whether that was decided at time of sanction or whether it's done now?

MR. COLAIACOVO: From a ratepayer perspective?

MR. SIMMONS: Right.

MR. COLAIACOVO: As long as the redress happens before they begin paying the bills –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – the effect – the practical effect is the same.

MR. SIMMONS: Okay.

MR. COLAIACOVO: Now I have – I'm – I've looked very – at a very high level –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – at the proposed changes –

MR. SIMMONS: Yes.

MR. COLAIACOVO: – but they're – they appear to be along the lines of what you suggest.

MR. SIMMONS: Right.

Is it something as simple as saying the government won't collect its dividend or will return its dividend to the utility so it can be applied against rates – that would probably be, from what I can see, the clearest example of how value would be transferred from the taxpayer to the ratepayer.

MR. COLAIACOVO: Yeah, and there is a risk that, in fact – so there are two different issues, right? One is the balance between the ratepayers and taxpayers –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – and, you know, particularly, for example, all the value from exports –

MR. SIMMONS: Mmm.

MR. COLAIACOVO: – in the original decision in 2012, all export revenue was supposed to go to the shareholder as opposed to the ratepayer –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – which seems, on its face, to be quite unbalanced. Because ratepayers are paying the full cost of the underlying asset that's producing that export energy. So, you know, it doesn't appear consistent with traditional regulatory economics where ratepayers get the value of assets that they pay for. So, you know, that's a clear example.

On the other hand, taxpayers did put in real equity in the project –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – and would expect some return on that equity. But it always – returns on equity are not guaranteed, they're not set in stone, there is always a risk involved. So, should the taxpayer get an 8 per cent return on equity regardless of what happens, that's not how the markets work. That's not how shareholder returns work.

MR. SIMMONS: That's not even how utility regulation works.

MR. COLAIACOVO: That's not even how utility regulation works, right? So, you know, is it fair for all value to be transferred from taxpayers to ratepayers? No.

MR. SIMMONS: Mmm.

MR. COLAIACOVO: But there has to be some sharing of risk burdens, right?

MR. SIMMONS: Right. And in your view, a rebalancing.

MR. COLAIACOVO: A rebalancing.

MR. SIMMONS: Okay, good.

Thank you very much. I don't have any other questions.

THE COMMISSIONER: Thank you, Mr. Simmons.

Concerned Citizens Coalition.

MR. HISCOCK: Good morning, Sir, Will Hiscock on behalf of Concerned Citizens Coalition, and that's a group of individuals who were early critics of this project, early persistent critics. I have a number of questions for you; the first one is on the financial risks after commercial operation.

On page 13 of your report, under risk to the Newfoundland and Labrador government, you mentioned the additional equity to fund cost overruns, and there are other financial risks to the province after all equity has been injected and commercial operations begin.

Are there other financial risks after all the equity has been taken care of? I guess, basically, are there financial risks that flow to the province through NL Hydro's Power Purchase Agreement and the obligations to the Muskrat Falls Corporation, even after the equity is in place?

MR. COLAIACOVO: Sorry, I'm just trying to get the – so on page 13 of my report – so it says, "Additional equity required to fund cost overruns …." And then, "Loss of provincial economic competitiveness in the event that costs to ratepayers prove higher than budgeted."

Those – that's what you're referring to?

MR. HISCOCK: Yes, and Madam Clerk, if we can go back to 04445, it was there under NL Government –

THE COMMISSIONER: So can I – sorry, I'm just lost right at the moment because I'm still trying to find out where you are.

MR. HISCOCK: Okay.

THE COMMISSIONER: So are we on the presentation that Mr. Colaiacovo –?

MR. HISCOCK: No, the report. Not the presentation.

THE COMMISSIONER: (Inaudible.)

MR. HISCOCK: Yes.

On the report, there's a chart – Table 2 it's called, and there's an NL Government section here where they're looking at the risks and opportunities and costs and the benefits. And under the Risk section, there's the equity to fund cost overruns, is noted there, right?

But there's other financial risks to the province after all of the equity has been injected and after the commercial operation begins, correct?

MR. COLAIACOVO: Well, the financial risks – I mean, there's – typically, there is financial risk in owning any corporation, but those wouldn't actually be – I don't think the financial risks inherent in Nalcor would be different afterwards than they are before, as long as it was fully funded. I mean, there's always financial risk in owning an enterprise, but I don't know that those would actually change.

MR. HISCOCK: There's a Power Purchase Agreement, right, with – and NL Hydro is on the hook, right, the take-or-pay –

MR. COLAIACOVO: Well, ratepayers –

MR. HISCOCK: – contract.

MR. COLAIACOVO: Ratepayers are on the hook, in fact.

MR. HISCOCK: Okay.

MR. COLAIACOVO: So it's ratepayers that are on – and that's why in the row above, Newfoundland ratepayers are the ones who are at risk for that take-or-pay contract. That's a ratepayer risk as opposed to a government risk.

MR. HISCOCK: Well, I'd suggest to you that the ratepayer risk is flowing through NL Hydro, and in a situation where that can't be borne, it's NL Hydro who, ultimately, is going to be left holding the bag on that, and that's backed by the Government of Newfoundland and Labrador.

So while it may not be a direct risk to the Government of Newfoundland and Labrador as a legal entity – on the first instance – as the people who are backstopping NL Hydro and Power Purchase Agreement through that federal loan guarantee mechanism –

MR. COLAIACOVO: Right, but –

MR. HISCOCK: – the Power Purchase Agreement –

MR. COLAIACOVO: – the federal loan guarantee mechanism required that legislation be put in place to ensure that take-or-pay contract could ultimately be recovered from ratepayers. So not even the regulator is in a position to reject those costs, was my understanding, and that makes it a ratepayer risk because it flows through NL Hydro, but it flows to ratepayers.

MR. HISCOCK: Okay.

So if NL Hydro puts out the bill and the ratepayer can't pay, right, then it's NL Hydro?

MR. COLAIACOVO: Yes.

MR. HISCOCK: You know what I mean. If that comes to a crunch where the Power Purchase Agreement is forcing us to buy more electricity than we can actually afford, the rates can't go that high et cetera, et cetera. It's NL Hydro but really it's the government who's backstopping that Power Purchase Agreement.

MR. COLAIACOVO: It's the taxpayer.

MR. HISCOCK: It's the taxpayer. So that's a risk that –

MR. COLAIACOVO: But –

MR. HISCOCK: – carries on long after the equity is invested in this project, right?

MR. COLAIACOVO: Yes. That – there is always a contingent liability that flows back to the government and I think that's true of all public infrastructure.

MR. HISCOCK: Okay. And we've discussed in this Inquiry before – because this isn't necessarily a remote risk. And to suggest it's on the ratepayers, I'd suggest, isn't necessarily that real, in that price elasticity means that if we keep raising the price, people are going to start using – they will stop being ratepayers. You know, the citizens will stop being ratepayers 'cause they won't use the electricity. They'll find alternate sources of energy, or leave the province. I mean, really, people, you know, can only afford to pay so much on a heat bill.

So to suggest that ultimately it's not really a risk to the province because the ratepayers will pick up the bill, presumes the ratepayers can afford to pick up the bill.

MR. COLAIACOVO: But the – this is also where you – well, you're correct. There is a theory in energy economics that – and utility economics of a death spiral.

MR. HISCOCK: Yes.

MR. COLAIACOVO: Right?

MR. HISCOCK: And that's what I'm taking about, it's in a death spiral –

MR. COLAIACOVO: That is if prices –

MR. HISCOCK: – yeah.

MR. COLAIACOVO: That's right. That if prices go – ultimately are increased high enough, then demand collapses which causes prices to go higher until the system falls apart. And the – in that instance, because Newfoundland Hydro is owned by the province, then the residual risk falls on the province. You're correct.

MR. HISCOCK: Okay.

If – the next question is on the strategic value of the alternate route. And I appreciate what you've been suggesting in terms of there being a real value to the combination of – well, basically the Labrador link and then the Maritime Link as well, but being able to flow power through to northeastern United States, effectively, directly from Labrador.

I wonder if there was really as much strategic value, though, as you've suggested in a certain sense. And that is that, you know, these kind of subsea cables and so on have been laid internationally, have been built internationally. The technology was readily available, correct?

MR. COLAIACOVO: The technology was available and some – and subsea work has been done, but I think that the work done in the Straits of Belle Isle, for example –

MR. HISCOCK: Mm-hmm.

MR. COLAIACOVO: – pretty unique. There are not very many subsea cables that are in iceberg danger zones. And even the Maritime Link is fairly unique in terms of its length. There were some real advances there.

MR. HISCOCK: Okay. Because I would've thought that it was less – that the question was rather – it would've been less whether it was technically feasible rather than to prove that it was economically feasible, and that that would be the real advantage in terms of Churchill Falls. Wouldn't be for us to say, you know, now we realize we can lay undersea cables, and this is a big step forward because technologically –

MR. COLAIACOVO: Yeah.

MR. HISCOCK: – we didn't think last year we could do that.

MR. COLAIACOVO: It's not just a technological thing, though, because this also involved negotiation between two different provinces, between two different utility companies –

MR. HISCOCK: Mm-hmm.

MR. COLAIACOVO: – coming to agreements that span, you know, the entire route into the United States. It's more complicated than just the technology of laying undersea cables.

Back in the 1960s, there were some undersea cables, right? But it was simply considered impractical and not feasible at the time. The reality is putting together the Muskrat Falls plan and the transmission route, all right, and the co-operation between the utilities and the indication, frankly, from Emera of them, you know, since that time, also exploring another transmission cable to go from Nova Scotia to Massachusetts and so on. All of that kind of development points to the reality of this alternate route.

MR. HISCOCK: Okay. So it wouldn't have been the technical as much as the economics of the undersea linkages, and then the commercial or almost political success of being able to make arrangements with Emera, Nova Scotia and through New Brunswick, that that political, commercial arrangements were in place. That's one of the big strategic –

MR. COLAIACOVO: Yeah, I think it's –

MR. HISCOCK: – values here more so?

MR. COLAIACOVO: – the combination together. It's the technical success –

MR. HISCOCK: Mm-hmm.

MR. COLAIACOVO: – right? But it's also the commercial arrangements and the demonstration of political will to get it done.

MR. HISCOCK: Have you costed what sort of upgrades would have been – would be needed in Nova Scotia and New Brunswick, or do you know if there would be upgrades needed in Nova Scotia and New Brunswick if we were to try and bring through actual Churchill Falls power –

MR. COLAIACOVO: No, you would need –

MR. HISCOCK: – you know, at 2041 (inaudible)?

MR. COLAIACOVO: – you would need brand new lines.

MR. HISCOCK: Right.

MR. COLAIACOVO: You would – it would only make sense to do a full DC line, likely directly all the way to the United States, potentially with one off-ramp in Atlantic Canada. It would have to be entirely brand new. To carry that much power, you couldn't rely on any of the existing systems.

MR. HISCOCK: And that would require new arrangements with Emera, Nova Scotia and –

MR. COLAIACOVO: Absolutely.

MR. HISCOCK: – so on, all the way through.

MR. COLAIACOVO: Yep.

MR. HISCOCK: Okay.

So we're not saying that we've got anything in place for 2041, but we've done it once; we can do it twice.

MR. COLAIACOVO: That's right.

MR. HISCOCK: That's effectively the argument.

MR. COLAIACOVO: That's right.

MR. HISCOCK: All right.

If Hydro-Québec and the Government of Newfoundland and Labrador reach an impasse, what is our worst case scenario? If new transmission lines through the Island, across the Strait of Belle Isle and Cabot Strait are not economically feasible as an alternative to wheeling through Quebec, what would be our options at that point?

MR. COLAIACOVO: Well, I'm not sure why they wouldn't be economically –

MR. HISCOCK: Okay.

MR. COLAIACOVO: – feasible. Because I think they – that's the whole point, is that the infrastructure put in place in Muskrat Falls has shown that it is economically feasible to carry that power. So it's created that actual option.

MR. HISCOCK: Has the economics of the trans-Labrador really been demonstrated though?

MR. COLAIACOVO: So the cost of going from a three-strand, 900-megawatt Labrador-Island Link to go up – you know, multiply the number of strands: 15 strands to get to 5,000 megawatts. You're not multiplying the cost of the link by five, right? Because you have a route. You, you know – it's – do I know the exact cost numbers? No, I don't. I think you would have to have engineers to cost out the whole thing. But you also would be going – you wouldn't be going to bottom – no, sorry, not Bottom Brook – Soldiers Pond. You would be going directly, you know, across the Island and then down to Nova Scotia. And then –

MR. HISCOCK: Right.

MR. COLAIACOVO: – from Nova Scotia, you would keep on going. It would be a different – a slightly different route, a different infrastructure. But I don't think you would simply multiply the cost of the existing infrastructure to come up with that cost estimate.

MR. HISCOCK: I'm just suggesting the mere existence of this Inquiry and its work suggests that the economics of the project that has been built are somewhat in question at the moment.

MR. COLAIACOVO: Yeah, but is that because of the transmission infrastructure, or is it because of the power generation station?

MR. HISCOCK: I would suggest it's – the evidence is towards the power generation, but nonetheless, I think it does raise questions all around to suggest that this is – you know, that we've staked our claim to being able to do this economically and that it is economically feasible because we've already done it. It strikes me as a little bit maybe of an overstatement in that the current project has got its own issues, and we would be looking a slightly different route and a lot more cable; we don't necessarily know what that number would be that would upgrade the power system in Nova Scotia, upgrade the power system in New Brunswick via a line from there after.

MR. COLAIACOVO: Right.

MR. HISCOCK: We don't have those costs in there.

MR. COLAIACOVO: You're right. But I think they are calculable and I think that's an effort worth pursuing. I think it also has to be borne in mind that it is the second-best option, right? The best option is a transmission route through Quebec. It's shorter; it's more efficient. But that second-best option is important because it creates a negotiating position.

MR. HISCOCK: And the only other option we would have if the economic – if the route through to the United States following the Maritime Link and so on, if that route wasn't economically feasible, then our only alternative with the Churchill Falls power is – besides keep giving it to Quebec at whatever Quebec demands – is to use it ourselves.

MR. COLAIACOVO: Yeah.

MR. HISCOCK: And while that may be feasible, that would effectively make the whole Muskrat Falls generation plant a waste of time. It would – you could mothball it and have no difference really –

MR. COLAIACOVO: Well –

MR. HISCOCK: – you know, at that point.

MR. COLAIACOVO: – you're still getting power from the Muskrat Falls generating station. Yes, it's expensive because of the cost that it's turned out –

MR. HISCOCK: But we would have more free power than we could possibly use anyways out of Churchill Falls, so excess power is of no value, really, at that point. Is there any way we could use all the power from Churchill Falls and still need Muskrat Falls power?

MR. COLAIACOVO: Well – yeah, that's interesting. The – so one of the options in a place like Labrador is, for example, server farms, which are being built in places like

Iceland. And, you know, server farms use a massive amount of power. They also have cooling requirements, so being in a colder environment is good. You know, theoretically, you could build an enormous number of server farms and run them on power from something like Churchill Falls. Is that practically feasible to use, you know, effectively 3,500 megawatts worth of baseload? You know, probably not. Could you use some of it? Absolutely, you could, right.

MR. HISCOCK: And we could look at methods of using that but, I mean, your evidence yesterday, I mean, we looked at the two key energy-eating ones, that would be one, aluminum smelting being the other one.

MR. COLAIACOVO: Mmm.

MR. HISCOCK: We could fill Labrador with that stuff. The chances that we use all of the Muskrat Falls –

MR. COLAIACOVO: (Inaudible.)

MR. HISCOCK: – or Churchill Falls power is slim. And the chances that – that the additional power from Muskrat Falls would have any value under that scenario, would you agree, is remote?

MR. COLAIACOVO: I think you're assuming – I think you're making the assumption that getting the power to market is uneconomic.

MR. HISCOCK: Yeah.

MR. COLAIACOVO: And if you make the assumption that getting the power to market is uneconomic, that's gonna throw a question on any power that's coming out of Labrador. In which case, building local demand is the only way to have value, right.

MR. HISCOCK: And if we build the local demand, then Muskrat Falls – the reasonableness of Muskrat Falls generation starts to look very precarious.

MR. COLAIACOVO: Right.

MR. HISCOCK: Okay.

Cost overruns, on page 45 you say, "In the case" – and this is from your report, I'm generally going to be referring to the report and not the slideshow presentation.

THE COMMISSIONER: So that's 04445, then.

MR. HISCOCK: Yes.

On page 45 you say: "In the case of the Interconnected Island plan, sensitivities for construction cost overruns were calculated in the 2010 version of the models. Note, however, that in 2012 CPW calculations, cost overrun sensitivities were not" – sorry – "specific to the Muskrat Falls Project, but were instead calculations of generally increased capital costs for all plan assets over the entire 50-year span. Moreover, model runs which included schedule failures were not made public during the Muskrat Falls Review process, and no such model runs from 2012 were included in information made available to MPA for this report."

Does this mean that the increased capital costs were applied equally to both options to the – okay.

MR. COLAIACOVO: When they ran the sensitivities and they said 25 per cent increase in capital cost, they increased not only the Muskrat Falls cost by 25 per cent, but they also increased the cost of everything else in both of the plans by 25 per cent and then ran the calculations. When I did my calculations, I did an alternative where I only increased the cost of the Muskrat Falls plan by 25 per cent and then looked at that in comparison with the Isolated Island plan.

MR. HISCOCK: Would you agree that there was an oversight in that initial planning – and obviously you do, or I assume, because you went and done it yourself afterwards – but in applying those cost increases equally to the two different options, when one would be expected, given the history of megaprojects that have the large –

MR. COLAIACOVO: I think –

MR. HISCOCK: – cost overruns?

MR. COLAIACOVO: – yeah, I think you're testing two different things, right. On the one hand, I was interested in testing what if there was a cost overrun with the project.

MR. HISCOCK: Mmm.

MR. COLAIACOVO: Right. There is a separate scenario where you ask what if all projects just become more expensive, because all projects have to meet higher standards or something, and it costs more money to do projects. Fine, right? Those are actually two different things. Probably worth testing both of those different things.

MR. HISCOCK: Mm-hmm.

MR. COLAIACOVO: But my point was at the time, they didn't look specifically at just the project going over budget and what would the impact of that be.

MR. HISCOCK: Right.

On page 50 of your report, you say the following – and I'm just gonna read this into the record there: "The PPA price was not found through the use of a simple mathematical formula, but instead was the result of iterative financial modelling. This was required in part because of the commitment to make the PPA an inflation-adjusted fixed price for 50 years (i.e., the initial price … be set at in-service, then adjusted upwards every year by the projected 2% inflation rate)."

And Morrison Park tested the – sorry – has Morrison Park tested these iterative calculations to understand fully how the PPA works in setting prices over 50 years?

MR. COLAIACOVO: I examined the modelling that was done.

MR. HISCOCK: Mm-hmm.

MR. COLAIACOVO: I looked at several different steps in the iteratives.

MR. HISCOCK: Sure.

MR. COLAIACOVO: Didn't go through every single one of them, but I basically did it enough to understand what PricewaterhouseCoopers was doing and, you know, they did exactly what they said they were doing with it, so.

MR. HISCOCK: Okay.

In your report again, at page 51 this time, you stated: "In short, export prices were projected to grow much … faster than inflation from 2017 to 2030, before retreating to inflationary growth thereafter. This assumption was embedded into the PPA price, and hence was a feature of the CPW analysis. Had a lower export price scenario been tested, would have resulted in a higher PPA price, and hence a less compelling picture for the Interconnected Island plan in the decision-making process." That's from your report.

MR. COLAIACOVO: Mmm.

MR. HISCOCK: Are you saying that this led to a lower CPW for the Interconnected Option and made it appear more attractive than the Isolated Island Option?

MR. COLAIACOVO: Yes. This was in the modelling that was done in the summer of 2012. And I think I've got a note in here somewhere, but –

MR. HISCOCK: Mm-hmm.

MR. COLAIACOVO: – the arrangements on the federal loan guarantee were not finalized at that point. The arrangements for the federal loan guarantee were only finalized, I think, in November. And so when they finalized the arrangements on the federal loan guarantee they actually made a change in the way this – the PPA price was calculated because they fixed it at an 8 per cent return from domestic sources, regardless of exports – regardless of exports.

But in the summer of 2012 when they went through the modelling exercise and put the results before Cabinet, the – what I say here in this paragraph is true –

MR. HISCOCK: Mm-hmm.

MR. COLAIACOVO: – the assumption about export prices did actually effectively lower the PPA price, for – that fed into the CPW calculations, right? But the final PPA price, it was set regardless of exports.

MR. HISCOCK: Okay.

I'd like to ask you a few questions about the disaster scenarios that you've – in your report. On page 56 of your report you refer to the scenarios and you say: "'Disaster' scenarios for any particular plan should be a particularly strong focus for analysis, because the preconditions for 'disaster' need to be thoroughly understood, and the possibilities for mitigation in the course of such a scenario should be considered. If a plan is ultimately chosen, the combination of variables that might lead to disaster should always be top of mind."

Do you consider where we are today with Muskrat Falls to be a disaster scenario?

MR. COLAIACOVO: Well, my understanding is that the budget is now over $4 billion higher than it was at the time of the decision, which is more than 50 per cent increased. That generally qualifies as a disaster, yes.

MR. HISCOCK: And if we combine that with dramatically lower exports prices than were predicted and a low demand in absolute terms, not only not growing at the rates that they had suggested, those other factors would also tend towards a disaster scenario?

MR. COLAIACOVO: Yeah, that, I think, is fair to say. That is at the – one of the bottom corners of the grid of possible scenarios.

MR. HISCOCK: Yeah. In our worst-case scenarios we're headed – we're looking at one of those –

MR. COLAIACOVO: Right.

MR. HISCOCK: – really nasty scenarios that you would've modelled.

MR. COLAIACOVO: That's right.

MR. HISCOCK: On page 58 you say the following: "As a result of the fact that many Nalcor assets are not included in the financial models (nor are any Newfoundland Power assets or independent power producer assets either), it is not possible to make any calculations about ultimate ratepayer prices or total costs based on the information presented (though Nalcor did so during the Muskrat Falls Review, based on additional information). The CPW models available deal only with part of the power supply for the Island, and can only be evaluated based on how well they do what they aim to do."

I'd like to bring us to Exhibit P-01988, and this is a Nalcor presentation – 01988, Madam Clerk – is a Nalcor presentation, and we're going to page 29 of that presentation.

The presentation shows the revenue requirements for Muskrat Falls at 11.66 cents per kilowatt hour of the blended costs in 2021, of 22.89 cents per kilowatt hour. This amounts to $808 million in revenue requirements for 2021. The same table, on page 29, shows other costs amounting to $794 million, an amount of comparable magnitude.

Would you expect that a similar balance between Muskrat Falls and non-Muskrat Falls assets would apply throughout the CPW period?

MR. COLAIACOVO: You have me at a disadvantage with this material. I looked at this presentation in the past, but I'm not sure what exactly you're trying to get at here.

MR. HISCOCK: Well, the balance, I guess, between Muskrat Falls assets and non-Muskrat Falls assets, when we look at it here, it appears to be a rough balance between the two.

MR. COLAIACOVO: Right.

MR. HISCOCK: And I'm wondering if you have any reason – or, I guess, have any thoughts after the materials you reviewed, as to whether you would expect that to change much during the CPW period. If there was discussion in any of it about other assets dropping off. I mean, obviously Muskrat Falls is Muskrat Falls. I guess it's the – the question is on the non-Muskrat Falls –

MR. COLAIACOVO: Right.

MR. HISCOCK: – assets, you know?

MR. COLAIACOVO: Yeah, so if you recall, the take-or-pay contract causes Muskrat Falls to deliver an increasing amount of power every year –

MR. HISCOCK: Mm-hmm.

MR. COLAIACOVO: – to Newfoundland. Some is set aside for exports, but in the first years it's approximately 2,000 gigawatt hours. By the time you get out to the 50th year it's 5,000 gigawatt hours. So it's a rising volume of energy. It really does depend on the future of load growth in the province as to what the balance is between Muskrat Falls costs and other costs.

So if load grows to absorb more of that power as time goes by, then the balance between Muskrat Falls power and other power on the Island, you know, may be fine –

MR. HISCOCK: Yeah.

MR. COLAIACOVO: – if the load doesn't grow and it has to be exported at some price, compared to whatever the cost is in the take-or-pay contract, then that will change these balance calculations. So it's very difficult to speculate what the balance will be.

MR. HISCOCK: Okay.

On this, we have – on this page 29 of this exhibit there's – the blended cost is 22.89 cents per kilowatt hour.

MR. COLAIACOVO: Mm-hmm.

MR. HISCOCK: I'd like to take you to chart 5 in your own report. If we could go back to the main report and to page 59 of that report? And I'm wondering if that figure, the 22.89 cents, is comparable with the green line in chart 5?

MR. COLAIACOVO: Right. Okay.

So the green line here is showing the dollars per megawatt hour in nominal dollar terms in the reference case that the power from Muskrat Falls was supposed to be, you know, charged to Newfoundland ratepayers at.

And so if you're – if you note that the dollars per megawatt hour, the scale on the right hand side – so 100 and 200 – and so that – you can see that in the early years, that power was costing for, you know, approximately – well, just under 20 cents a kilowatt hour – $200 a megawatt hour, right?

MR. HISCOCK: Mm-hmm.

MR. COLAIACOVO: And that would've been the cost of the power from Muskrat Falls in the reference case, in nominal dollar terms, and then rising at time goes by. But it's a – in the early years, because only 2,000 gigawatt hours is being delivered, it's a relatively small part of the pool of power that's being consumed in Newfoundland because Newfoundland's load is something on the order of 8,000 to 9,000 gigawatt hours.

And so the bulk of power is still coming other assets in Newfoundland in the early years, and that was always the intention, and then as that –

MR. HISCOCK: So – sorry, does this reflect the – is this is blended cost, then?

MR. COLAIACOVO: No. This is not the blended cost.

MR. HISCOCK: This is the Muskrat-specific cost –

MR. COLAIACOVO: This is the just the –

MR. HISCOCK: – right?

MR. COLAIACOVO: – Muskrat cost.

MR. HISCOCK: Okay. Yeah. That's what – that's – I guess I wanted – that's one of – the main thing I wanted to make sure –

MR. COLAIACOVO: Yeah.

MR. HISCOCK: – that we had out of this was that –

MR. COLAIACOVO: Yeah.

MR. HISCOCK: – that this is not the blended cost for –

MR. COLAIACOVO: No.

MR. HISCOCK: This is the Muskrat Falls –

MR. COLAIACOVO: It's –

MR. HISCOCK: – specific cost.

MR. COLAIACOVO: – exclusively –

MR. HISCOCK: Okay.

MR. COLAIACOVO: – Interconnected Island incremental power, and that was the point that I made in that line that said it's – you know, the blended cost was not available.

MR. HISCOCK: No.

MR. COLAIACOVO: You need a whole bunch of other information in order to calculate the blended cost.

MR. HISCOCK: How will the energy and unit-cost numbers shown in charts 5 and 6 be affected if load were level throughout with zero load growth? If the load growth (inaudible) – if our future load growth –

MR. COLAIACOVO: Right.

MR. HISCOCK: – if we just levelled out energy use at this point –

MR. COLAIACOVO: So –

MR. HISCOCK: – how would that change these?

MR. COLAIACOVO: Yeah.

And so the difficulty with that is you can't – it doesn't actually make sense. I didn't – in my analysis, I calculated some of those scenarios –

MR. HISCOCK: Mm-hmm.

MR. COLAIACOVO: – with low load growth, but I only calculated the net cost because in effect what you're doing is your exporting some of this power.

MR. HISCOCK: Right.

MR. COLAIACOVO: Right? And so what happens is the green line just shoots way up because you're exporting the power at a loss, right?

MR. HISCOCK: Right.

MR. COLAIACOVO: So where the power, you know, from Muskrat Falls costs call it 20 cents, or something like that, and if you are only exporting it a five, you have to make up the 15 difference, right.

MR. HISCOCK: Okay.

MR. COLAIACOVO: So the net cost to the Newfoundland ratepayer for the reduced amount that you actually use becomes very, very expensive.

MR. HISCOCK: And it is – and it's all – let's just go back there, in a scenario where we have low or no load growth, were exporting increasing amounts of power rather than using that power.

MR. COLAIACOVO: Right.

MR. HISCOCK: We're selling it at whatever 25 per cent of its cost –

MR. COLAIACOVO: Well, depending on what the export price is at the time.

MR. HISCOCK: Yeah. But it is going to be at a loss almost certainly?

MR. COLAIACOVO: Yes.

MR. HISCOCK: Okay. And it's the ratepayer who then is going to – the ratepayer who is – use home efficiencies or something to keep their own load down, so we've got no load growth in Newfoundland. The effect of increasing efficiencies and so on within the Island is that we subsidise an increasing amount of exports to America or whatever.

MR. COLAIACOVO: We have the same problem in Ontario right now.

MR. HISCOCK: Yeah. I think it might be useful, and certainly my clients believe it would be very useful, if these charts were able to be updated to reflect the changed circumstances, cost overruns, and low power demand that we've been seeing.

MR. COLAIACOVO: Yeah. The difficulty with – as I mentioned in the report, when you change the load profile, what you're also doing is you're changing assumptions about the necessity for assets in the future, right? So, even the Interconnected Island plan – yes, Muskrat Falls get built, but the Interconnected Island plan assumes that in 2032, you build your first combustion turbine –

MR. HISCOCK: Mm-hmm.

MR. COLAIACOVO: – right? But if load is lower, you probably don't need to build a combustion turbine in 2032. So that actually changes the costs in the Interconnected plan, right? If you – maybe you don't need that combustion turbine until 2037, right? So, you delay it by five years; it's going to reduce costs; it's going to change the curves. But in order to calculate those kinds of impacts, you have to run a Strategist model.

MR. HISCOCK: Yeah.

MR. COLAIACOVO: Right? So that's not something that I could've done. You know, it's a system-planning, a resource-planning problem. Given a much lower load than was assumed back in 2012, you have to plan for a different future and make adjustments at this point.

MR. HISCOCK: Have you seen anything to suggest that information, the current rates and so on and the current projections that were being given are based – have taken into account the realities of this reduced load? Because the load seems to have a very significant impact on these models over time, right, in terms of the costs –

MR. COLAIACOVO: Yes, it does.

MR. HISCOCK: – just as much as the capital cost of the project up front is going to drive it. Decreased load is really going to drive these costs up as well, aren't – isn't it?

MR. COLAIACOVO: Yeah, decreased load makes an enormous difference to the performance of the system from a financial perspective.

I think that applications to the regulator over the last few years, you know, for approval for rates and so on in the medium term have been updating the load projection each time –

MR. HISCOCK: Mm-hmm.

MR. COLAIACOVO: – and adjusting accordingly. All of the participants in the Newfoundland Power system have to make adjustments based on –

MR. HISCOCK: Yeah.

MR. COLAIACOVO: – what's happened.

MR. HISCOCK: I'd like to talk a little bit about your planning scenarios you discussed and including 2041 here. You continue to come back to the Churchill Falls contract and, just for an example, on page 57 you say – quote – "It should … be stated here that Churchill Falls, and the dramatic strengthening of Newfoundland's strategic position vis-à-vis Churchill Falls, was not addressed as part of the scenarios and models presented. In certain versions of models presented at various stages of the decision-making process there was reference to the eventual availability of energy from Churchill Falls after 2041, but the broader issues of strategic and commercial value were simply never addressed." It wasn't "taken … account in the CPW calculations, nor was there any attempt made to suggest, in any addendum, how the value of Churchill Falls might play into the decision-making process." You carry on from there.

Would this have led you to select a shorter time horizon, one which segued into 2041? I mean, you've talked about doing the CPWs at various stages –

MR. COLAIACOVO: Yeah. I think –

MR. HISCOCK: – but –

MR. COLAIACOVO: – the question of – I think it is limiting to consider only 50 years, right? It's important to understand what happens to ratepayers over time. And I think even in the reference case – and, you know, those two charts that you just had up a minute ago, actually show you that the Isolated Island plan was going to be cheaper even in the reference case between, you know, the beginning of the period and 2032, 2033 approximately.

MR. HISCOCK: Mmm.

MR. COLAIACOVO: And then it becomes more expensive in the reference case. And it's important to recognize that, right? Yes, over 50 years, the Interconnected Island plan is cheaper in the reference case, but there is an explicit trade-off. It's more expensive, but you know, until 2033 or so, and then it's cheaper. And, you know, that should have been recognized. And looking only at a 50-year CPW kind of covers that up.

MR. HISCOCK: Yeah.

And because we have, you know, one of the most important – arguably the most important resource in the Island coming back into the fold in 2041 – and really our power generation needs are amply met and then some from even a trickle from Churchill Falls – wouldn't it have made a fair bit of sense to find a way of bridging those just couple years, like, '33 to '41, '35 to '41? We're talking about six years of expensive power –

MR. COLAIACOVO: Yeah.

MR. HISCOCK: – it doesn't seem excessive, you know.

MR. COLAIACOVO: So I think it's a legitimate question to ask about what the viability of the Holyrood station would be for that period of time.

MR. HISCOCK: Mm-hmm.

MR. COLAIACOVO: I mean, the Holyrood station was first commissioned in 1971. It's an oil-fired station. It's already coming up to 50 years as it is, and oil-fired stations typically don't last that long. So you – to say that you could add 20 more years of life on to it, you know, you would have to ask engineers, but I think you're raising some very tough questions about whether it could be made to reliably last that long.

And if you have to build anything new, that becomes then the question, right? If you're building something new to bridge a small number of years, how much money are you stranding in that process? And then you have to build the transmission line because, yes, the power is going to be available at Churchill Falls in 2041, but you're still going to have to build the Labrador-Island Link at that point in order to get access to that power, right? So –

MR. HISCOCK: But, in fairness, we are either going to have to build it anyways or we're going to get hit for basically the cost of building it from Quebec and not build it.

MR. COLAIACOVO: Right.

MR. HISCOCK: So, you know, that's an investment that's coming down the road, either as a lost opportunity and we shovel the money over to Quebec, or we spend it ourselves and get the link built, right? So that money was going to be – is going to be spent quite likely, right?

MR. COLAIACOVO: Yeah. But, you know, if you had to build, for example – if Holyrood was failing, and you had to spend a billion dollars on a new oil-fired combustion turbine facility, and that combustion turbine facility would have 30, 40 years of life in it, reasonably, but you only needed it for five or 10 years and then you're writing it off because, essentially, you have access to Churchill Falls power, you know, then you have to amortize that stranded asset to ratepayers and that would have to be calculated.

And so I think, in fairness to Nalcor, they did that calculation –

MR. HISCOCK: Mm-hmm.

MR. COLAIACOVO: – right? They calculated, okay, replace the Holyrood plant with a new oil-fired combustion turbine and then build a transmission line to Churchill Falls in 2041 and strand the oil-fired plant –

MR. HISCOCK: Yeah.

MR. COLAIACOVO: – and amortize it to ratepayers, and it doesn't look attractive. In the reference scenario, it certainly doesn't look attractive.

MR. HISCOCK: In the scenario where we were told that the reliability of a – of power coming out of Labrador was problematic and we could have major interruptions and that there was strong advice that we have an alternative – as in basically a replacement for Holyrood for standby power in case the power gets knocked out for a year in Southern Labrador, would that – that knocks out that whole scenario, though, because we got to build a power plant anyways, then, in that case, right?

MR. COLAIACOVO: I'm sorry, I'm a little confused about what you're –

MR. HISCOCK: Well, my understanding is, is there's been fair evidence at this Inquiry about reliability issues and that a replacement for Holyrood might almost be required not even from a generation perspective, but from a reliability perspective or that it would be advantageous from a reliability perspective, given the distance that our energy is now travelling and the topography –

MR. COLAIACOVO: Yeah.

MR. HISCOCK: – and geography, et cetera.

MR. COLAIACOVO: Yeah. Normally transmission lines that are multiple – like, multiple wires, when you've got redundant transmission capacity, that's considered reliable. I mean, there are lots of jurisdictions that have long transmission lines. Quebec itself has long transmission lines, as does Manitoba, as does BC, as does Ontario.

And in many instances, you don't have local generation to compensate for the long transmission lines. You rely on the fact that you have redundant transmission capacity. And that's what your reliability is.

What you're building here in the Labrador-Island Link is a three-strand transmission line, designed, you know, for reliability purposes. So I am somewhat surprised at that comment.

MR. HISCOCK: So from your view, that wouldn't be a consideration on the reliability front and – but the Muskrat – what we're talking about, though, anyways is that – I guess you would agree that if – that Holyrood is the big piece – big piece of the puzzle in terms of giving an advantage to an Interconnected system is not having to replace Holyrood –

MR. COLAIACOVO: That's right.

MR. HISCOCK: – that otherwise the Island made – the Isolated Island Option and deal with it in 2041 would have made perfect sense, except that we would have this stranded six-year-old facility –

MR. COLAIACOVO: (Inaudible.)

MR. HISCOCK: – or whatever-number-year facility – okay.

I'd like to jump on to page 71 of your report, talking about the federal exposure – the limited federal exposure on this deal. You note on that page: "The Government of Canada provided a debt guarantee" to the province "and effectively took the entire debt of the Project as a contingent liability on the Canada balance sheet," that allowed "the project to benefit from a much lower interest rate than would have otherwise been possible. However, the FLG required stringent commercial terms to support the project such that the scenarios in which there is a default that would invoke the federal government's participation are almost certainly limited to natural disasters of epic proportions." End quote.

You make no reference to insufficiency of demand or weakness in the provincial economy. Is this because your understanding is that the province has guaranteed that all cost will be paid and the federal government will be indemnified against all adverse economic events as contrasted with a natural disaster (inaudible)?

MR. COLAIACOVO: I don't think there's an explicit guarantee of that kind anywhere, but if you look at the construction of the arrangements –

MR. HISCOCK: Mm-hmm.

MR. COLAIACOVO: – that's effectively what happens, because there's a take-or-pay contract –

MR. HISCOCK: Yeah.

MR. COLAIACOVO: – and a take-or-pay contract is legally enforceable and – you know, so therefore it goes to ratepayers. And as you've pointed out, in the absence of ratepayers in that potential extreme future –

MR. HISCOCK: Death-spiral scenario, yeah.

MR. COLAIACOVO: – it – the death – you know, the death-spiral scenario, it then falls to the shareholder of Newfoundland Power, which is the provincial government.

MR. HISCOCK: Right.

And so that structure means that really Newfoundland has got to be wiped out before Canada is at risk?

MR. COLAIACOVO: Yeah, a more likely scenario is, as I've said here, a massive storm that actually attacks the assets themselves and therefore, you know, you can't transmit the power, the power is stranded; therefore no – you can't deliver on the take or pay contract and therefore the liability doesn't fall on the Newfoundland ratepayer, the liability falls on the project.

MR. HISCOCK: Okay.

MR. COLAIACOVO: All right.

MR. HISCOCK: (Inaudible.)

MR. COLAIACOVO: And therefore the federal loan guarantee supports the project.

MR. HISCOCK: So it's really a scenario where, for physical – reasons of physical technical limitations, we're not able to get the power to the ratepayers in Newfoundland.

MR. COLAIACOVO: That's right.

MR. HISCOCK: In that instance, the federal government could be in trouble. In any scenario where power makes it to the Island –

MR. COLAIACOVO: Right.

MR. HISCOCK: – it's the province that's on the hook.

MR. COLAIACOVO: That's right.

MR. HISCOCK: Okay.

MR. COLAIACOVO: Yeah, that's the way that the arrangements are constructed so – and if – I don't know, if there's an explosion somewhere and it, you know, destroys a critical piece of infrastructure, a switching station, whatever –

MR. HISCOCK: Yeah.

MR. COLAIACOVO: – if the power can't flow, then the federal loan guarantee becomes relevant.

MR. HISCOCK: Okay.

MR. COLAIACOVO: Right?

MR. HISCOCK: Next question is one I've put to several people and I think we've actually already kind of brushed up against this, which is: Is it even possible for a rate of return to be guaranteed on a project like this? Like, the suggestion that we can guarantee an 8 per cent return, would you agree that that's – if certain assumptions hold up, that might be possible –

MR. COLAIACOVO: Yeah.

MR. HISCOCK: – but in the reality of the real world economics –

MR. COLAIACOVO: Yeah.

MR. HISCOCK: – there's no way to actually guarantee a rate of return.

MR. COLAIACOVO: So, people use terms like "guarantee" very loosely. In finance, nothing is guaranteed in the colloquial sense that you're talking about.

MR. HISCOCK: Yeah.

MR. COLAIACOVO: It's just – you're only talking about order of priority. That's all you're talking about, really.

MR. HISCOCK: Yeah, exactly, okay.

Power Purchase Agreement, I'd like to move on to that there for a moment or get into that a little bit further. It's found – we have it as an exhibit and it's Exhibit number, Madam Clerk, 00457, for the Power Purchase Agreement.

How unusual is it for a Power Purchase Agreement to have no fixed price and to be signed on a take-or-pay basis?

MR. COLAIACOVO: Well, in order to have an agreement, you have to have either a price or a formula. It's not uncommon to have a formula, for example. You could have a Power Purchase Agreement that says you're going to – the price in the future is going to be a function of some index. For example, you can sign a contract that says: I will pay you the price of power equal to the current price of gas times X, for example. Or, you know, in order to have – you can have an agreement that says: I will pay you a power price based on today's $100 multiplied by inflation whatever it is.

MR. HISCOCK: Sure.

MR. COLAIACOVO: So you either need a price or you need a formula, it's one or the other; otherwise, you don't actually have an agreement, right? But you can do it on a formula basis without a price as long as there's a formula included.

MR. HISCOCK: Right. And have you ever seen a formula that was – had as much variance in it, in that really the ratepayers had no idea what they would be paying when they signed an agreement saying that they would promise to pay?

MR. COLAIACOVO: Typically, when you see Power Purchase Agreements, and they're all different shapes and sizes, you can forecast, you know, within a reasonable range, what the Power Purchase Agreement is going to cost. I think what you're trying to get at, though, is more of an impact on the blended price and visibility of that impact downstream.

MR. HISCOCK: Mm-hmm.

MR. COLAIACOVO: And I think that's often very, very difficult because, in many jurisdictions, Power Purchase Agreements are only a small component of the total system. And so, the impact of any given Power Purchase Agreement, on the whole system cost, is not particularly visible. So, I don't think that's an uncommon problem.

MR. HISCOCK: Okay.

Outside of that – the scale of the PPA in this case, is there anything else that you found particularly unique or unusual about the PPA in the Muskrat Falls scenario?

MR. COLAIACOVO: Well, it's a 50-year PPA, which is long. Most common renewable energy PPAs are typically 20 to 25 years – for wind and solar and that kind of thing. Or for natural gas plant, PPAs are often in that range. Natural gas plants, though, typically are on a contract-for-differences structure, it's an index structure rather than a PPA structure. But there are contracts in Ontario for small hydroelectric facilities that were built recently, they are 40 years long. So, 50 years is not completely unheard of.

MR. HISCOCK: Okay.

If we could turn to Exhibit 03440 – 0-3-4-4-0 – where former PUB chair, Bob Noseworthy, is referring to the memorandum of principles, MOP, outlining the commercial arrangements to enable the financing of Phase 1 of the Lower Churchill Project. This was dated August 31, 2011.

This relates to the development of the Power Purchase Agreement in November of 2013 – that we just had a look at there. It's an Information Note describing – sorry – it's an Information Note describing consultations by the Department of Natural Resources with former PUB – and that's Public Utilities Board in Newfoundland – chair, Bob Noseworthy and with Power Advisory consultants.

On page 1, Bob Noseworthy is quoted as saying that, quote: "… there has been a clear shift from protecting the interest of the ratepayer as contemplated in the MOP to a focus on ensuring the financial viability of the Project in the Term Sheet. Mr. Noseworthy believes there is no benefit accruing to NLH in the early years, with Nalcor receiving all of the benefit."

Do you agree that that – do you agree, based on the PPA of November 2013, that that statement is accurate? Or that sentiment?

MR. COLAIACOVO: Sorry, I'm trying to find the –

MR. HISCOCK: Sorry.

MR. COLAIACOVO: – where the line up here –

THE COMMISSIONER: Straight under Departures from the Memorandum of Principles.

MR. HISCOCK: Departures from the Memorandum.

MR. COLAIACOVO: Ah, the – okay, sorry, there it is.

MR. HISCOCK: Yeah.

MR. COLAIACOVO: Right.

Right. So, I think it's entirely true that the federal loan guarantee requires the financial viability of the project, and is very much focused on that issue. The terms of the PPA, which in a significant – to a significant degree, how were structured in order to satisfy the federal loan guarantee, I think, you know – do reflect the sentiment. Because – excuse me – it's inherent in the take-or-pay nature of it, and the fixed-return element of it. And, you know, even in the reference scenario, it results in costs that are higher than they would have been in the Isolated case, right.

So, the – I'm not sure about the assessment of there is no benefit accruing to Newfoundland and Labrador Hydro in the early years, with Nalcor receiving all of the benefit – that's a pretty sweeping statement. But clearly, the terms of the federal loan guarantee did shape the way the PPA was structured.

MR. HISCOCK: I have a few other comments, and – by Mr. Noseworthy, from this document. I'd like to run through a few of them with you and get your comments –

MR. COLAIACOVO: Sure.

MR. HISCOCK: – in relation to those.

On page 4 of the same document, Mr. Noseworthy makes the following statements – I'm gonna run just through a couple of them and get your reaction, okay?

"Overall assessment is that there is a clear shift from protecting the interest of the ratepayer as contemplated in the MOP to a focus on ensuring the financial viability of the Project in the Term Sheet." We went through that one.

"… Term Sheet stipulates that all the risk is bourne [sp. borne] by NLH.

"Muskrat has a fairly high per unit cost, and arguably not least cost in the early years. Benefits may accrue over time, but Base Block payments would initially be much higher than market prices. It may be least cost over a 50 year time period, but not in the first 15-20 years." That's what you were saying as well, right?

MR. COLAIACOVO: It's all true.

MR. HISCOCK: Exactly on the same stuff a few years earlier.

"There is no benefit for NLH in the early years. Nalcor retains all" the "benefits." We went through that.

So, I'm gonna – I have a couple more comments. Do you have anything particular on that?

MR. COLAIACOVO: No, I agree with those – sentence.

MR. HISCOCK: From page 5 of this same document then, further quotes from Mr. Noseworthy:

"Under the Term Sheet, NLH has a significant and disproportionate risk profile when compared to its rewards." It's an – "It is extraordinary that the risk is bourne [sp. borne] solely by NLH with no sharing of liability." And Hydro here would really be a stand-in for the ratepayers.

MR. COLAIACOVO: That's right.

MR. HISCOCK: Okay, so you would agree with that comment.

"NLH is paying for the main assets in full and paying off all" financial "costs without owning anything at the end of the term except for a right to negotiate with Nalcor in good faith for future power needs."

MR. COLAIACOVO: Yes.

MR. HISCOCK: "A 50 year demand forecast up front is not normal and presents considerable risk" to the ratepayers to Newfoundland Labrador Hydro.

MR. COLAIACOVO: That's correct.

MR. HISCOCK: Okay.

"In general, NLH assumes all the risk and receives no benefit, while Nalcor assumes none of the risk and gets all the benefits."

MR. COLAIACOVO: Yeah, again, I find the statement somewhat sweeping about assumes all the risk and receives no benefit, but – because he acknowledged himself in this that after the first 20 years, it is cheaper.

MR. HISCOCK: Yeah.

MR. COLAIACOVO: Okay, so …

MR. HISCOCK: Yeah.

In addition to the Information Note from – that's the end of my comments on that particular section there. In addition, the Information Note from the Department of Natural Resources – that's the one we've been looking at here – also reports on consultations with Power Advisory.

Power Advisory – and this is on page 3, Madam Clerk – they say that, quote, Newfoundland – NLH, Newfoundland and Labrador Hydro, "is guaranteeing a minimum return to Muskrat which 'mitigates the project's risk and enables financing' while Muskrat and Nalcor enjoy the upside" while sharing – while not sharing, no sharing of benefits with Newfoundland and Labrador Hydro and its customers.

Do – I mean this is – again, this is what the BPA has set up as the formula, right?

MR. COLAIACOVO: That's right.

MR. HISCOCK: And so the rate mitigation plan that my friends have discussed, that's the first step in trying to re-address a pretty egregious –

MR. COLAIACOVO: Right.

MR. HISCOCK: – imbalance in your view.

MR. COLAIACOVO: And that was what I pointed out in my report. The references here are all to Newfoundland and Labrador Hydro. My – and, briefly – and finally it says: And its customers. My focus was always on the customers –

MR. HISCOCK: Yeah.

MR. COLAIACOVO: – because, to me, Newfoundland and Labrador Hydro is just a conduit that leads to customers.

MR. HISCOCK: Right.

And so, you know, you've raised this inequity now and the government is addressing it now, but these are comments from six years ago, right?

MR. COLAIACOVO: Mm-hmm.

MR. HISCOCK: So this is not – this was something that was highly knowable and realizable from day one on this project in the way the PPA was structured, right? Okay.

If we could turn to Exhibit 00454 and that's the Grant Thornton report, on page 38 of that report it discusses the PPA there. Page 38, Madam Clerk, thank you.

So – yes: "The PPA provides specific remedies if Base Block Payments are not made. In particular, if NLH fails to make the necessary

Base Block Payments while MFCo continues to be in compliance with this agreement, MFCo may provide notice to NLH it is invoking" its "rights under the PPA which requires that within 10 days of providing such notice, if NLH has not paid the outstanding payment, NLH is required to pay a lump sum amount equal to the full repayment of the debt financing (including principal, accrued interest" payments and "premiums) plus any associated costs (including legal, advisory, transaction and administrative costs)."

Please note as well that the PPA, the Power Purchase Agreement, at page – or, sorry, between Hydro and the Muskrat Falls Corporation was signed in November 29, 2013, and it provides for a return on equity and a return – a return on equity – and a return on equity.

Section 1 of Schedule 1 includes the following definition – and this is around base block capital cost recovery, because we know that that's a chief mechanism inside the PPA, right? Base block capital cost recovery means the recovery over the supply period of the following costs without duplication: (a) "development capital costs, which shall provide for the repayment of principal under the financing and the return of equity capital to the equity holder;" (b) "development financing costs;" and (c) distribution to equity holders sufficient to enable Muskrat to achieve its assigned IRR.

If Newfoundland and Labrador Hydro cannot – and this is the question for you: If Newfoundland and Labrador Hydro cannot provide sufficient revenues to meet these financial obligations, does this mean the provisions that the – sorry, that the province must provide the funding?

MR. COLAIACOVO: If – and I don't know the answer to this question, but if Newfoundland and Labrador's – Labrador Hydro's debt is guaranteed by the province, then, yes.

MR. HISCOCK: Yeah.

Do these financial obligations include operation and maintenance costs, thereby committing the province to operating the assets even when the business case for such operations would demand a shutdown?

MR. COLAIACOVO: Typically – and I don't know –

MR. HISCOCK: Okay.

MR. COLAIACOVO: – the answer to that question.

MR. HISCOCK: Yeah.

MR. COLAIACOVO: Typically, these kinds of provisions are designed to satisfy debt obligations. So what is being transferred here, effectively, is liability for the debt obligations of Muskrat Falls.

MR. HISCOCK: Yeah.

MR. COLAIACOVO: And that's what's being passed on.

MR. HISCOCK: And they flow from Muskrat Falls through Hydro, effectively to the province –

MR. COLAIACOVO: That's right.

MR. HISCOCK: – and the taxpayer. Okay.

Independent validation of costs is the next question I have for you, and I've only got, I think, three left here.

During this Inquiry, the subject of the independent validation of costs has been raised several times by the Commissioner with Charles Bown and the Premier – and Premier Dwight Ball. Mr. Noseworthy – and this is the gentleman from the Public Utilities Board we were speaking about earlier there – said the following: "With the ratepayer being required to cover all costs incurred on the project, it is incumbent on the province to ensure that costs are independently reviewed and released to the public in a report.

The "Public needs to have faith in the costing, especially where they bear all the costs directly in rates." The Public Utility Board "is not likely the proper party to complete the review."

Could you please comment on the need for the independent validation of costs?

MR. COLAIACOVO: Well, in large infrastructure projects, there's often multiple layers of consulting engineers, consulting advisors, consulting project cost specialists and so on. I can simply tell you from experience that when I was chief of staff to the minister of Energy in Ontario, we made a decision to proceed with refurbishment of a nuclear facility, which was a sizable – the first of several. And even the first one was a sizable expenditure. It had been quite controversial.

There were three layers of cost review specialists who were involved. Ontario Power Generation itself – that was whose project it was – they had hired external engineers and cost specialists to work on it. The government brought in a separate set of specialists and cost experts to review the project again and track the project week by week, practically, because of the controversy surrounding that particular project. And so, regular updates were provided on how the project was going and how it was performing against budget and schedule and so on and so forth.

It's not atypical, on very large projects, for lenders, as well as owners and other parties involved, to have separate sets of consultants and specialists who are overseeing a project or at least tracking a project.

MR. HISCOCK: And that would've been 14 or 15 years ago that you were involved in that –

MR. COLAIACOVO: That's right.

MR. HISCOCK: – judging approximately by your biography.

MR. COLAIACOVO: That's right.

MR. HISCOCK: And so, at that point – and with that project, that refurbishment, have been as large a capital cost project as Muskrat Falls?

MR. COLAIACOVO: No, that one was – the final bill was about $1.3 billion.

MR. HISCOCK: So a much smaller project and relative – obviously, Ontario being a much larger province and you had three layers at that point.

MR. COLAIACOVO: That's right.

MR. HISCOCK: Okay.

I'm going to go – carry on with the – this is in relation to your fairness test. Mr. Noseworthy, the gentleman from the Public Utilities Board, makes the following statement about the fairness of the Power Purchase Agreement. And I don't think a lot of people have spoken about fairness, so I bring Mr. Noseworthy in because he was one of the early people to relate the fairness question and it's something you've raised again and brought out.

That he was "not aware of any other utility in North America that: Can generate its revenue at no cost; Gets transmission for free; Has another entity assuming all of its risk; Generates its product at no cost; Is tax-exempt; and Has the possibility of securing a federal loan guarantee." Can you think of anybody – any other utility that's ended up in a similar circumstance in terms of seeming to accrue a lot of advantages without the corresponding risks or the downside of those same arrangements?

MR. COLAIACOVO: I find it somewhat difficult to sympathize with the parsing of entities that this gentleman's perspective seems to be pursuing. Newfoundland and Labrador Hydro is owned by the provincial government. Nalcor is also owned by the provincial government.

You know, risks have – are in Newfoundland and Labrador Hydro's hands in this formulation and not in Nalcor's, and he's criticizing the location of those risks in the Newfoundland and Labrador Hydro entity and the fact that risks are not in the Nalcor entity. From my perspective, they're both entities owned by the provincial government; therefore, the – it's the province that has those risks.

MR. HISCOCK: Mm-hmm.

MR. COLAIACOVO: My concern was much more, actually, the ratepayers –

MR. HISCOCK: Yes.

MR. COLAIACOVO: – and the fact that Newfoundland and Labrador Hydro would be calling on the ratepayers to make good on those risks. The parsing of risk allegation between entities, both owned by the provincial government, doesn't strike me as being the primary issue, right?

MR. HISCOCK: Right, because we're just talking about corporate versions of the same people –

MR. COLAIACOVO: That's right.

MR. HISCOCK: – or the same interest, I guess.

MR. COLAIACOVO: That's right.

MR. HISCOCK: Sister companies, if you would, or something.

MR. COLAIACOVO: Exactly.

MR. HISCOCK: Yeah.

MR. COLAIACOVO: I mean if one was owned by the province and another was a private sector company, that would be a different issue, right?

MR. HISCOCK: Yes.

MR. COLAIACOVO: That would be a real transference of risk. But, I mean, the criticism that's being levelled here, I'm not sure what the point of that criticism. If what he's trying to say is that risk is being put on the shoulders of ratepayers, I agree with that but, you know, that's not what seems to be coming off the page.

MR. HISCOCK: No, I can understand that critique. Are you aware – and this is my final question for you, I believe, is: Are you aware of any Power Purchase Agreements or power contracts that have ever been overturned by the courts because of their inherent unfairness to stakeholders?

MR. COLAIACOVO: I don't know the answer to that question.

MR. HISCOCK: Thank you.

Those are all my questions.

Thank you, Commissioner.

THE COMMISSIONER: All right, thank you.

I think we'll take our break here now.

[Approximately 24 seconds audio recording lost due to technical issue.]

Recess

CLERK: All rise.

Please be seated.

THE COMMISSIONER: Right.

Kathy Dunderdale.

MS. E. BEST: No questions. Thank you.

THE COMMISSIONER: Okay. Thank you.

Julia Mullaley, Charles Bown. Or – I'm sorry – I missed the Former Provincial Government Officials (inaudible) –

UNIDENTIFIED MALE SPEAKER: I have no questions, Commissioner.

THE COMMISSIONER: – apologize.

UNIDENTIFIED MALE SPEAKER: Okay.

THE COMMISSIONER: Julia Mullaley, Charles Bown.

MR. FITZGERALD: No questions, Commissioner.

THE COMMISSIONER: Robert Thompson.

MR. COFFEY: Good morning. My name is Bernard Coffey. I represent Robert Thompson, who was the former clerk of the Executive Council – or is the former clerk of the Executive Council – and at one point was the deputy minister of Natural Resources. Okay? He was head of the civil service and a deputy minister.

Just a couple of questions. The – if you bring up, please, Exhibit P-04464, page 26. Ah, yes. And you've been referred to this – you referred to it yourself, and it's been referred to in questioning.

When you say at the bottom of the page there: "The available evidence, at least on its face, does not appear to be sufficient to justify this conclusion." And that is, of course, I presume, the text in red.

MR. COLAIACOVO: That's right.

MR. COFFEY: Okay. Is it – the available evidence – evidence available to whom?

MR. COLAIACOVO: Publicly available.

MR. COFFEY: (Inaudible.)

MR. COLAIACOVO: Publicly available.

MR. COFFEY: Publicly available. Okay, as opposed to – in other words, in relation to, I suppose, whatever was in public releases as well as that put before the PUB in 2011, 2012, that –

MR. COLAIACOVO: That's right.

MR. COFFEY: – that time. Okay. And you did, I think, this morning indicate that you've seen material, though, in the exhibits here relating to what I'll refer to as, you know, social benefits.

MR. COLAIACOVO: That's right. That's what I said.

MR. COFFEY: And they were before Cabinet.

MR. COLAIACOVO: That's right.

MR. COFFEY: And presumably taken into account.

MR. COLAIACOVO: I think the one that leaps – the issue that leaps off the page is stabilize rates.

MR. COFFEY: Yes.

MR. COLAIACOVO: The statement that says meet future energy needs, I think, is clear, and then the significant economic, employment and social benefits, that's a conclusion of the government based on internal Cabinet documents, and that's fine. Though, those weren't actually made public –

MR. COFFEY: (Inaudible.)

MR. COLAIACOVO: – at the time. But stabilized rates, I think, is a contentious position to have taken, and not necessarily borne out by all the material that had been presented.

MR. COFFEY: Well the – if – at 7.4 billion all in, which was the original projection, and if it had come – had been constructed in the timeframe originally publically suggested, the stabilized rate, would you agree, you know, based upon the formulas that existed, that it would've been stable, it would've been known beforehand? You could calculate it beforehand as to what it was, it was gonna be, using the PPA, the intergeneration agreement, and the Labrador-Island Link lease, technically. It's a combination of the three of them. You could –

MR. COLAIACOVO: So –

MR. COFFEY: – have done the calculation as to what it was gonna cost.

MR. COLAIACOVO: So even in the reference case, published by the government – or sorry, by Nalcor – even in the reference case, costs were higher in the Interconnected plan than they were in the Isolated plan.

MR. COFFEY: Yes.

MR. COLAIACOVO: And cost pressures in the Interconnected plan were higher in the early years.

MR. COFFEY: Oh yes, yeah. It would stabilize rates in the sense of you could predict, and it was predicted in 2012, what they would be in 2018. As it turns out, it was – you know, as it turns out costs were – the cost had been higher and therefore the rates are – would have to be higher, barring mitigation. But there were predictions as to what the rates would be in 2018 and onward, and assuming that it had been done –

MR. COLAIACOVO: Right.

MR. COFFEY: – on time and on budget, those rates would be increasing two per cent a year, whatever – whatever the – two-point-what-odd per cent – but the point is that you could peg them and watch them.

MR. COLAIACOVO: If you assume the reference case.

MR. COFFEY: Yes.

MR. COLAIACOVO: And the reference case is only one of many possible –

MR. COFFEY: Oh yes.

MR. COLAIACOVO: – scenarios. So again, had there been any better clarity around the range of possible futures for the project, making a claim that rates would be stabilized as a result of all of those possible futures, it – the two things actually don't hold together.

MR. COFFEY: Well I – you know, I see the point you're getting at, but it's implicit in this, isn't it? You know, and you would take issue with whether it should be. But it's implicit in this that stabilized rates, in this context, assumes it's on time, on budget.

MR. COLAIACOVO: On time, on budget, but also that load works out, you know, to – according to –

MR. COFFEY: Yes.

MR. COLAIACOVO: – the projection, and fuel prices work out according to the projection and so on and so forth. I mean, there's an awful lot of assumptions –

MR. COFFEY: Oh yes.

MR. COLAIACOVO: – an awful lot of things that have to go right, in order to have stabilized rates. And I don't think there was – my point here is that there was not sufficient data provided, not sufficient evidence provided to show that in fact that was going to be the case.

MR. COFFEY: Okay.

And – now the Commissioner in the past – and I just raise this because he has raised it with other witnesses in the past. I think at one point the Commissioner floated a question or posed a question of, you know, how the Nova Scotia Block that's to be delivered under the arrangement with Emera could be valued in – you know, should be valued because it's not actually going to result in, like, any deposit of money, you know, in this province in the sense that it, you know, is an actual explicit payment for it.

So, you know, and I'm just going to assume – kind of from a rough calculation, assume for the moment that it's a terawatt hour a year, and I appreciate, you know, it's the –

MR. COLAIACOVO: Some bit less than that, but yes.

MR. COFFEY: – a little bit less but it's a little bit more in some of the early years and so on and so forth.

MR. COLAIACOVO: In the first five years –

MR. COFFEY: Five years.

MR. COLAIACOVO: – and then it's 895 a year.

MR. COFFEY: So, my point being this – just to have it addressed if you can – what's your understanding of what Nova Scotia Power is paying – what Nova Scotia ratepayers are paying for the 1 terawatt hour, from their perspective?

MR. COLAIACOVO: So the valuation is actually crystal clear.

MR. COFFEY: Yes.

MR. COLAIACOVO: It's $1.6 billion of capital cost to build the Maritime Link –

MR. COFFEY: Mm-hmm.

MR. COLAIACOVO: – charged –

MR. COFFEY: And what does that work out per –

MR. COLAIACOVO: – charged to ratepayers on a cost of service basis over 35 years with a 9.5 per cent return on equity and the cost of debt from the federal loan guarantee. So you can actually work it out –

MR. COFFEY: Yeah.

MR. COLAIACOVO: – and when you look at the total delivery of the power, including the first five years, we did this exercise –

MR. COFFEY: Yes, I – yeah.

MR. COLAIACOVO: – you know, but I'm going off the top of my head because I don't have –

MR. COFFEY: Yeah, sure.

MR. COLAIACOVO: – the report in front of me. But my recollection is that the LUEC of that power is in the range of $100 – its $90 to a – somewhere in the range of approximately $100 a megawatt hour.

MR. COFFEY: Which is 9 to 10 cents per kilowatt hour.

MR. COLAIACOVO: That's right. And that's the LUEC of it. And so from – I think from a Nalcor perspective, if Nalcor had spent the money to build the Maritime Link and had chosen to – sold that power on the market as opposed to the –

MR. COFFEY: Yes.

MR. COLAIACOVO: – through the Maritime Link Agreement Nalcor would today, I believe, be getting less than that in the export market.

MR. COFFEY: Yes.

MR. COLAIACOVO: So the Maritime Link agreement, therefore, is actually better than having built it themselves and exporting the power.

MR. COFFEY: Yes. And as well, in – because the – I think the Commissioner uses – his explicit words were, I'm going to – I shouldn't say explicit but paraphrase him. I believe he'd referred to, like, for an example or from the perspective of our province, Newfoundland and Labrador, the opportunity cost of the terawatt hour. And I'm going to suggest to you the following: A terawatt hour a year at a cent per kilowatt hour is $10 million.

MR. COLAIACOVO: Yeah.

MR. COFFEY: That's the calculation. And therefore at five cents a kilowatt hour, let's say, if you could get five cents – and it is – I think Hydro-Québec, in recent years, had been getting between four and five cents a kilowatt hour – that would be $40 to $50 million, the opportunity cost. In other words, we're delivering power; we will deliver power, a terawatt hour a year. That, in theory we could get, gross, four to five cents a kilowatt hour, we'd make $40 to $50 million gross.

MR. COLAIACOVO: Less transmission cost.

MR. COFFEY: Less – yes, you know, less transmission. Loss is in the cost –

MR. COLAIACOVO: Mmm.

MR. COFFEY: – associated with it. So the actual opportunity cost of that would be, in fact, considerably – you know, the figure would be considerably less than the $40 or $50 million.

MR. COLAIACOVO: Quite likely.

MR. COFFEY: Quite likely.

MR. COLAIACOVO: Yeah, because you'd – Nalcor is not required to pay any transmission tariff on the Maritime Link.

MR. COFFEY: Yes.

MR. COLAIACOVO: But once you reach the Nova Scotia border –

MR. COFFEY: Oh yes.

MR. COLAIACOVO: – at Woodbine, then you have to pay the standard Open Access Tariff to get through Nova Scotia, through New Brunswick, into the first market that's available in Maine.

MR. COFFEY: Yes.

And the – I just raise the issue with you because of your background expertise. And you seemed as good – you know, better than perhaps, if not all, most witnesses to address the issue of the idea of opportunity cost of that terawatt hour.

Thank you, Commissioner.

THE COMMISSIONER: Right.

Just before I call on the next person, I just want to go back to this for a minute. So – and that's fine.

MR. COFFEY: Okay.

THE COMMISSIONER: Thanks, Mister …

I'm just – what I've been trying to figure out is that if I was to look at the cost of a project, normally I would look at it in with regard to what the – what were the repercussions or what were the ramifications of my deciding to build the project.

So, in this particular case, what I find a bit interesting is that Newfoundland and Labradorians were told that the cost was going to be $6.2 billion at the time of sanction, plus financing, but there was no consideration of the potential cost, or that cost, for the Maritime Link. And at that stage, of course, no one would've thought about – or, obviously, they thought about it, but they sort of discounted the fact that there might be a reduced export market or whatever.

So let's assume for a moment that we have, you know, a project, and let's assume that things had remained the way they were and that it was carrying on forward. My question was: Wasn't that cost – wasn't that a cost that was a legitimate cost to be added to the $6.2 billion, the cost for what we were paying Emera.

MR. COLAIACOVO: No.

THE COMMISSIONER: Okay.

MR. COLAIACOVO: The capital cost of the entire Muskrat Falls plan was actually $7.8 billion –

THE COMMISSIONER: Right –

MR. COLAIACOVO: – which is the 6.2 plus the 1.6.

THE COMMISSIONER: Right.

MR. COLAIACOVO: But the 1.6 was being paid by Nova Scotia ratepayers. The – from a Newfoundland ratepayer perspective, Newfoundland ratepayers were paying for the construction of the Muskrat Falls facility. The Newfoundland ratepayers did not need the 895 gigawatt hours of power from Muskrat Falls because it was excess power in those 35 years, and so that power would've been exported.

Even in 2012 the average revenue that Hydro-Québec was getting for power at that time was below $60. If you look back to the 2003 to 2008 period, the prices that Hydro-Québec was getting, the average sale price was in the $80 to $90 range. When you –

THE COMMISSIONER: Okay, so is that spot market or –?

MR. COLAIACOVO: Spot – that's a blend of their –

THE COMMISSIONER: Of spot and –

MR. COLAIACOVO: – spot and contracts and –

THE COMMISSIONER: Right.

MR. COLAIACOVO: – everything. The spots are always lower than that, right?

So – but in 2012 it was much – I mean, significantly lower, right? And so if you look at the $1.6 billion of the Maritime Link and you trade that 895 gigawatt hours of power, for someone else spending that $1.6 billion of capital cost, it actually works out to be significantly advantageous. It's a good trade, frankly, for Newfoundland to have made. The –

THE COMMISSIONER: Yeah, I'm not questioning that, but let's assume for a moment that it wasn't – because the assumption all along was that exports were going to increase – the benefits from the exports or the price of the exports was going to increase over time.

So let's assume in 2012 that that was correct, so it wasn't $60, it was – they were going to be selling it at $90, a hundred dollars, whatever the scenario is.

MR. COLAIACOVO: Right.

THE COMMISSIONER: Is that not –

MR. COLAIACOVO: But the effect of cost of power to Newfoundland ratepayers is actually higher.

THE COMMISSIONER: Okay.

MR. COLAIACOVO: Because when I say that the LUEC was approximately a hundred dollars, that was the LUEC in 2012 dollars and that was a discounted calculation. So the actual dollar cost that applies to Nova Scotia ratepayers increases, so those – gigawatt hours actually get more expensive over time. So they're starting at a hundred dollars and they're going up from there. And so even if you assumed 2 per cent inflation on the export price – and the export prices would be going up – the cost to Nova Scotia ratepayers is also going up, right?

So that $1.6 billion of capital cost that was being absorbed by Nova Scotia ratepayers was more expensive than the expected forward curve of export market prices. That was one of the considerations in Nova Scotia: Why are we doing this? We're buying power effectively that's more expensive than the export market price, right? And the reason they were doing it is because not only were they buying that power, but they were getting access to potentially other power that would be at a lower cost, right? So they were balancing considerations in Nova Scotia.

But from a –

THE COMMISSIONER: Well – but, no, up to the time that – of the first UARB decision, and the UARB were not satisfied so they wanted – there was no guarantee that they were going to have any right to excess power.

MR. COLAIACOVO: That's right.

THE COMMISSIONER: So it was only at the second point, at the second decision, that that was – that basically was included.

MR. COLAIACOVO: Right, it was an option to purchase agreement – there was –

THE COMMISSIONER: Right.

MR. COLAIACOVO: – an option agreement –

THE COMMISSIONER: Energy Access Agreement.

MR. COLAIACOVO: – that was added to it. That – to be fair, what that did was it formalized what had been understood as being the case.

It was not a difficult agreement to negotiate because it had been understood between the parties that there would be an option to purchase. The regulator merely required a formal affirmation that, yes, there would be an option to purchase additional power and so that agreement was structured.

But the – you know, from the inception it was understood that there was going to be additional capacity on the transmission line, there was quite likely going to be additional power available and hence, Nova Scotia would have an opportunity to buy some of that additional power. And it would be cheaper than the 895 gigawatt hours, which was quite expensive – more expensive than the export markets, right?

THE COMMISSIONER: Right.

All right, thank you.

Consumer Advocate.

MR. HOGAN: Good – it's still morning, good morning.

My name is John Hogan; I'm counsel for the Consumer Advocate. So the Consumer Advocate represents the ratepayers involved in this project.

I want to take you to just a few follow-up questions on some of your slides in your presentation. So if we could please turn to P-04464 – sorry, there. So page 10, please.

So bullet point number 1 you say define the primary need. So obviously the need here is power, correct?

MR. COLAIACOVO: Well – and, more specifically, the replacement of the Holyrood plant.

MR. HOGAN: Okay.

We'll get to that then, I guess, but in terms of power, I'm just – and I'll show you some other slides and ask some questions about the two options we have over the 50-year period. But how do you define the primary need for power in terms of years? We know we need power but for how long and how do you determine what needs to be – what problem needs to be solved? Is it 10 years, 20 years, 50 years?

MR. COLAIACOVO: So when you're doing an integrated resource plan you start with a demand forecast, a load forecast. Then you look at all existing assets in the system and what their expected and planned useful lives are. And so you assess the capacity and energy capabilities of the existing assets and compare them to the load forecast.

There's, typically, as you – the further you go out as assets get old and are expected to reach the end of their useful lives, you have gaps that start to open up between load and available capacity and energy supply, and those gaps are what needs to be filled with new assets. And so you plan, you know, for the construction of new assets to fill the gaps. It's kind of standard integrated resource plan modelling.

MR. HOGAN: So, in this case, picking these two options – I mean, I'd suggest the base case was the Interconnected Option, and then because that was the base case over a 50-year lifetime, the Isolated Option, which you refer to as the most cost-efficient assemblage of other projects, is used to compare it to the base case.

MR. COLAIACOVO: Well –

MR. HOGAN: So I guess my question is, is the 50-year base case the right starting point?

MR. COLAIACOVO: Okay, so – yeah.

MR. HOGAN: And maybe you need to do further analysis, I don't know, but that –

MR. COLAIACOVO: No, no, no, no, no. If you had approached this from the perspective – like a blank sheet of paper, and said, okay, we have this problem that the Holyrood station is getting old, we have a load profile and we're suddenly going to lose 500 megawatts of our capacity and a large part of the energy profile – you know, for our system, how can we solve this problem? And that was the step that Nalcor went through in looking at all the different possible solutions: Wind and hydroelectric and so on and so forth.

There is no question that the Muskrat Falls plan was a baked transaction. It's a very complicated transaction, required multiple parties, required multiple governments, lots and lots of negotiations. And so, you know, it was the result of an enormous amount of effort and time. And, in that sense, it becomes a base case because there was a lot of investment in it, even before it was compared with any other options.

But in reality, if you go back several years before that, there – you know, the starting point would be an exercise – a resource-planning exercise that says we have an aging asset, Holyrood, and it's going to have to be replaced eventually and we're going to have to figure out how to do that. I mean that's fundamentally the need in the system because you have a load and you're going to be losing a significant asset.

The –

MR. HOGAN: But just – so that's fine and, obviously, the Interconnected Option would solve that problem.

MR. COLAIACOVO: Yes.

MR. HOGAN: But why then do you have to fill that need? Why does the comparator to the 50-year project have to be an assemblage of 50-year projects?

MR. COLAIACOVO: Well it's not an assemblage of 50-year projects; I mean the alternatives all have different lives. So a wind farm, for example, typically won't have a life longer than 30 years; and a natural gas turbine typically will last 25 to 30 years. I mean, these other assets that are involved – that are included in the Isolated Island plan – none of them really have a 50-year life.

MR. HOGAN: Just – yeah, just so we could look at page 21, please – don't mean to cut you off.

MR. COLAIACOVO: So the reason that you would choose to look at the 57 years, for example, is because the PPA contract was designed for 50 years plus construction.

MR. HOGAN: Well, the Interconnected PPA.

MR. COLAIACOVO: Absolutely.

MR. HOGAN: That's – you misunderstand my questioning though.

MR. COLAIACOVO: Right.

MR. HOGAN: You know, how do we know that these are the two lowest possible costs? All we know is that we have Muskrat Falls and the lowest possible cost of 50 – or 57-year plan is the Isolated Option, but how is that necessarily the lowest possible cost to the ratepayers –

MR. COLAIACOVO: Well –

MR. HOGAN: – today, tomorrow, in 20 years or in 15 years or seven years or –?

MR. COLAIACOVO: But it's not.

MR. HOGAN: Right.

MR. COLAIACOVO: And I think – you know, and I pointed that out – that even in the reference scenario, the Isolated plan is cheaper for – you know, until the early 2030s, right? In the documentation provided all the way through the decision-making process that was obvious. It wasn't highlighted, but it was in the data that was available.

The focus was typically on the CPW calculation, which is a full-life calculation of 57 years. One of the criticisms that I have is that there was too much focus on that single calculation. There should've been more of a thorough understanding and analysis of the different impacts that the options would have on people over time, right? And, you know, that was – one of the flaws in the process is that too much emphasis on a single metric, on a single time period.

MR. HOGAN: Right.

MR. COLAIACOVO: But, you know, when you're making long-term infrastructure decisions though, it's not necessarily true that ratepayers in the next 15 years – that you should automatically do what's better for ratepayers in the next 15 years if it's going to be worse for ratepayers after that. That's where judgment is required.

MR. HOGAN: Right, and it's complicated and you've been through lots of factors and – that weigh one against the other (inaudible).

MR. COLAIACOVO: Exactly.

MR. HOGAN: I guess when you look at the reference to the PUB, I mean you were involved in the UARB hearings, and our PUB was limited to two choices, so I guess this is what you're talking about. Can you comment on the reasonableness of this?

And you already said this morning, I think, that not only should the question be which is the cheaper option but there should be a broader question put to the PUB as well.

MR. COLAIACOVO: Well – and the PUB may or may not be the right forum for it, but it's often the forum that's available. The regulator is often the forum that's available.

So, in Manitoba's case, the regulator in Manitoba heard the NFAT reference from the government, and the NFAT – the needs for an alternatives to, is what NFAT stands for. The NFAT reference went beyond considering just ratepayer costs. Normally, the regulator only considers ratepayer costs, so it was a very specific reference, and they were directed to also pay attention to, you know, payments for taxes and environmental issues and the impact on the province and risks to the province's debt rating and so on and so forth. They were given specific leeway to consider issues beyond just costs and –

MR. HOGAN: And beyond just two options?

MR. COLAIACOVO: And – well, in that instance there were many options, so it was a bit of a different process. But, you know, normally regulators are focused exclusively on costs. So, you know, you do have to – if you're going to do a reference for a review, you can. A government always has the option to make things broader.

MR. HOGAN: Okay.

Can we just turn to page 12, please? So you're sort of talking about this, what you – what factors need to be considered and metrics are used. So you look at the customer/regulator metrics here, which is essentially the cost of paying their power bills. And there's other metrics to be considered, you've talked about that for the last day and a half.

But how does legislation fit in the metrics? And I ask because I'm not sure if you're aware, but we do have legislation in this province that says power has to be delivered at the lowest possible cost, consistent with reliable service.

MR. COLAIACOVO: Right.

MR. HOGAN: So I would think or suggest to you that those are the metrics that need to be used.

MR. COLAIACOVO: Well, in fact, that's one of the reasons, as I understand it, why the reference to the PUB in 2011 was limited to the cost issue, because of that piece of legislation. And so all of these other impacts, benefits, et cetera, were not supposed to be considered –

MR. HOGAN: Right.

MR. COLAIACOVO: – rightly or wrongly, but that's the legislation on the books.

MR. HOGAN: Right so the – okay, so they were not supposed to be considered. So then – and you used the word fuzziness this morning. Is it – can you comment on, or what's your opinion on the fact that there was fuzziness in the public about why this project was being done, what the benefits were, et cetera, et cetera?

MR. COLAIACOVO: Well –

MR. HOGAN: How fair is that to a ratepayer who's supposed to be getting the lowest possible cost, but is being told this is constructed for other reasons?

MR. COLAIACOVO: So, to be fair, I think what the government was saying at the time – what they were saying was not fuzzy. What I – my point was that the decision-making process may have been, but –

MR. HOGAN: No – yeah, I did – what they were saying was clear, but …

MR. COLAIACOVO: Exactly. The – I think they were claiming that it was the lowest cost and it would also deliver a bunch of other benefits. And, you know, therefore they were complying with the legislation at the time. I think that there was a legitimate question as to whether it was the lowest cost and, you know, because of risks and possibilities and scenarios and so on and so forth.

But I'm also, to be honest, critical of legislation like that, which is so black and white, because what does it mean to say that you –

MR. HOGAN: Well, it's not black and white.

MR. COLAIACOVO: Well –

MR. HOGAN: Or is it?

MR. COLAIACOVO: Well, no, the – if the legislation says you must provide power at lowest cost, to who, for how long, over what period of time? Does it always have to be lowest cost tomorrow? What if it's low cost tomorrow but more expensive the day after because I've made a certain choice? How do I comply with that legislation? That legislation – actually, it doesn't have a whole lot of meaning, right?

And so when the government chose to focus on a 50-year time horizon, it was justifying, I think – and I'm probably reaching here, to be fair – but it has a 50-year time horizon because it can plausibly claim that it's complying with the legislation. On a 50-year basis it's cheaper, but on a 15-year basis it's not cheaper. So are you complying with the legislation or not? Simultaneously you can say both of those things. Both of those facts are true, right?

The – that legislation is problematic, I think, on its face. I understand the spirit of what it says: Try to find the lowest cost way of managing your electricity system. But, in a modern context where many jurisdictions, Newfoundland included, are concerned about the environment, for example, many jurisdictions have chosen to build renewable energy, even if it's more expensive than oil- or gas-fired energy. Does the legislation say that you're not allowed to build a wind farm because wind farms are more expensive than oil, right? Is that the purpose?

So, you know, that kind of legislative restriction, I think, is problematic but, obviously, the government was trying to deal with it at the time.

MR. HOGAN: But the spirit is to protect ratepayers. You agree with that.

MR. COLAIACOVO: I agree with that.

MR. HOGAN: So decisions that are made then, if – around what is the lowest possible cost, should consider things like which project is more risky in terms of overruns, which project is going to be more of a guarantee that ratepayers will have the lowest possible cost.

MR. COLAIACOVO: Right.

MR. HOGAN: Yeah.

MR. COLAIACOVO: All of those elements are part of making a judgment.

MR. HOGAN: Right.

And you do have a table there where the Isolated Option is favoured because of things like we're not overbuilding, we're building as we need and there's less chance of overruns.

MR. COLAIACOVO: Yeah.

MR. HOGAN: Right.

Yesterday, you said the problematic scenarios for the Interconnected Option were not run. So based on your experience and your expertise – and you spoke about it a little with me already, that there was a big focus and a lot of work put into the Interconnected Option – does it show that there was a bias toward that option?

MR. COLAIACOVO: Bias is a loaded word. All of my comments have said that, you know, I think there should have been more work done at the time, more transparency about what these two different options meant, more data, more analysis.

Is the lack of that a result of bias or is it the lack of a result of, you know, lack of knowledge or lack of, you know, desire to spend the time and the money to do that extra work? I'm not going to speculate. I think bias is a very strong statement. I'm just not going to go there.

MR. HOGAN: Okay.

I will just turn to page 46. This is what I just mentioned, I think, please. So, yeah, power produced at need – on the right there, one of the reasons you would favour the Isolated plan.

So we have heard evidence from people who said that this project was overbuilt. We obviously didn't need the 900 megawatts; the Island didn't need 900 megawatts. So just – can you just explain – and maybe you already have – how that factor is accounted for in the overall analysis and how is that benefit weighed in favour of the Isolated Option when you're comparing the plans?

MR. COLAIACOVO: Well –

MR. HOGAN: Or is it a judgment call at the end of the day?

MR. COLAIACOVO: So many jurisdictions build in Canada – have built more power than they require with the expectation that they're going to export, right?

MR. HOGAN: Okay, I'll just stop you there because the – we – the public was sold this as we need it to meet our domestic needs and the export was not factored in; it was gravy if we get it.

MR. COLAIACOVO: No, I think that on its face the plan clearly says there's more power than is required in the early years and that power will be exported. I think there were – the documents were at pains to point out that the risk of the export price will not affect Newfoundland ratepayers and that was all part of the structure of the PPA.

But there was no question that part of the plan was exporting from the very beginning. And as I said, many other jurisdictions have built facilities and – with the plan of exporting; Quebec has done it, Ontario did it at different times in the past, Manitoba has done it and British Columbia has done it. It's not uncommon or unusual.

It's always risky, right? And there is a legitimate issue here about whether the degree of risk of pursing that plan was well understood or not, whether it was properly taken into account, whether the judgment at the time was sufficiently robust, you know, that understood what the risks exactly were and what might happen under those riskier scenarios, right? But it's – as I said, it's not the first time.

MR. HOGAN: Is it common in those jurisdictions where they do overbuild to commit the ratepayer to pay for the entirety of the project or just the portion of the project that they are going to use?

MR. COLAIACOVO: Well, the ratepayer is always – always – liable. So if you look at Manitoba's case, the ratepayer pays all the costs, minus whatever they can get from exports. In British Columbia it's a similar situation. In Quebec it's a similar situation. The cost is always part of the rate base for the utility. Historically, in Ontario, that was true until 1999 when the system was torn apart.

So, you know, again, it's not uncommon in Canadian terms, but that doesn't take away from the fact that it's always risky to do it. And in some cases it's turned out very badly, as it did in Ontario in the '70s and '80s with the nuclear plants, so …

MR. HOGAN: Okay.

You mentioned P-factors yesterday. I just want to ask a quick question on that. What's the impact on the analysis if you change P-factors, in terms of the gap between the Interconnected Option and the Isolated Option?

MR. COLAIACOVO: Right. And so that goes to the capital cost budget. And I noted from the materials that were exhibits and so on, about the capital cost budget being a P50 estimate versus P70, P90, P95 and so on and so forth.

So I don't know what the higher capital cost numbers were. I didn't actually see that in the exhibits and so I didn't run any modelling and analysis at a higher level. I did run the 25 per cent higher construction cost and so if that 25 per cent higher number corresponds to one of those higher P-numbers, then that's fine. But I actually don't know what the capital costs would have been in like a – in a P90 or a P95 scenario.

MR. HOGAN: So I just then – maybe this is just for my own understanding, it's kind of been bugging me. If you have a risky – one risky project and one not-so-risky project, say the Isolated and the Interconnected, I would assume if you raise the P-level the gap actually would close between the two.

MR. COLAIACOVO: No. So in the – so the probabilities – the construction cost probability numbers, P50, P90, P95, really typically only apply to large infrastructure projects. Something like a combustion turbine, it's an off-the-shelf project.

MR. HOGAN: That's my point though.

MR. COLAIACOVO: It –

MR. HOGAN: So the cost is what it is for the Isolated Option.

MR. COLAIACOVO: That's right.

MR. HOGAN: So a P50 versus a P70 is not going to be much different.

MR. COLAIACOVO: No.

MR. HOGAN: But a P50 versus a P99 for the Interconnected Option is going to be a different number.

MR. COLAIACOVO: Yes.

MR. HOGAN: So if you use –

MR. COLAIACOVO: And so –

MR. HOGAN: – P50s for each one, there would be a gap and if you use P99s, the gap will be smaller because –

MR. COLAIACOVO: But –

MR. HOGAN: – the Interconnected cost is going up.

MR. COLAIACOVO: But in the Isolated plan there is – it just doesn't make sense. You wouldn't – there's no relevance to a P50 –

MR. HOGAN: I know.

MR. COLAIACOVO: – or a P90 on the Isolated plan.

MR. HOGAN: Yeah.

MR. COLAIACOVO: So the only question is: Which capital cost do you use in the Interconnected Option? And if you use a higher capital cost in the Interconnected Option, then it just becomes more expensive.

MR. HOGAN: A bigger number. Yeah, okay.

Page 19 of your presentation, please. Now, you reference the options considered there – natural gas. I'm wondering if, I guess, that was not considered. Is that what the red means?

MR. COLAIACOVO: It was rejected.

MR. HOGAN: Rejected.

MR. COLAIACOVO: It was rejected.

MR. HOGAN: Okay.

And do you have any further evidence on that? And I'll just – why I'm asking is we did hear evidence from a Dr. Bruneau in Phase 1, his opinion that it was improperly rejected.

MR. COLAIACOVO: Yeah, I'm just not an expert and I wouldn't presume to get involved in that debate. I understand that there was some question as to whether it was viable to exploit nearby natural gas fields and bring them on to the Island or, alternatively, to build a re-gas facility for LNG.

I have some sympathy for the point of view that a re-gas facility wouldn't make sense because it would be much too large. Typically, re-gas facilities are very sizeable and a lot more than you would need for one power plant. If there had been a proposal basically to convert the entire Island to gas and create a gas distribution network and convince people to buy gas furnaces and so on, you'd be in a whole different world.

But, you know, on the question of whether nearby natural gas could be exploited –

MR. HOGAN: Yeah.

MR. COLAIACOVO: – I just don't know.

MR. HOGAN: Okay, that's fine.

I just want to talk about purchase of power from Hydro-Québec. So just a quick Google search I – you know, you look at 2010, Hydro-Québec entered into a 25-year contract with Vermont to sell 225 megawatts. Are you aware of this?

MR. COLAIACOVO: Mm-hmm.

MR. HOGAN: Yes, okay.

Do I have the facts right?

MR. COLAIACOVO: Sorry?

MR. HOGAN: Do I have that right?

MR. COLAIACOVO: Yes.

MR. HOGAN: Yes.

So this is 2010. Is there no commercial reason then for Hydro-Québec not to enter into a contract with Nalcor?

MR. COLAIACOVO: So a couple of issues.

MR. HOGAN: I stress the commercial reason; we'll get into other issues after that.

MR. COLAIACOVO: Yeah.

The contract with Vermont is a summer-peaking contract and Quebec has no problem with summer-peaking contracts, but it's also not cheap. So that – and I think that in large measure was what was being referred to by Nalcor in response to the intervenor question and the regulatory process.

Even though Nalcor – sorry, even though Hydro-Québec was, at the time, only getting revenues from exports on average in the $50 range, their contract with Vermont was actually priced substantially higher than that. So – because it's a firm power contract for an extended period of time and it would've been pegged to the price of gas – pegged to the price of a natural gas-fired facility.

And so I know from being in the market at approximately that time, that a natural gas-fired facility was priced at – back in the late noughts – in the 2008-2010 period, in the range of US $80 to $90, right? So in all likelihood – and I believe the terms and conditions of that contract were private – but in all likelihood it's probably structured at that kind of a level, which Nalcor would've found to be an unattractively high price.

So, the starting point is that Newfoundland would not have gotten a contract for any less than that.

MR. HOGAN: No.

MR. COLAIACOVO: And I think that's probably a fair assumption to make.

MR. HOGAN: Any less in terms of the capacity –

MR. COLAIACOVO: Get less of a price.

MR. HOGAN: – or the price?

MR. COLAIACOVO: No, any less of a price than that.

MR. HOGAN: But there would've been a – there would've been the ability to discuss it.

MR. COLAIACOVO: I'm sure.

MR. HOGAN: Yeah.

MR. COLAIACOVO: Absolutely.

MR. HOGAN: Okay.

Now, I just – you've mentioned Holyrood numerous times. Are you aware that our PUB is – has some concerns about there being a need for backup power to the Interconnected Option and, especially during the winter, which is what Holyrood would be there for, so it may not be closed any time soon.

MR. COLAIACOVO: So I've been told.

MR. HOGAN: So you've been told. Okay.

So my question is then: If we still need the thermal energy at Holyrood as a backup to the Interconnected Option, should that have been factored into the analysis of the Interconnected Option from the start?

MR. COLAIACOVO: I think if that is a system requirement, then, yes.

MR. HOGAN: Then yes.

MR. COLAIACOVO: As I said earlier, I find it surprising that that would be a system requirement, but I'm not an engineer and I – so will not get involved in that debate.

MR. HOGAN: Why do you find that surprising?

MR. COLAIACOVO: Because lots of energy systems rely on transmission connections.

MR. HOGAN: Sorry, rely on …?

MR. COLAIACOVO: Rely on transmission connections for their power. I mean, to give you a simple example; the City of Toronto uses 5,000 megawatts of power at peak in the summer. There is not 5,000 megawatts of capacity in Toronto's environs; all of that supply comes in by transmission connection. It comes from the Bruce and it comes in from, you know, other facilities around the province.

MR. HOGAN: So are you surprised that Holyrood is still needed? Is that the surprise?

MR. COLAIACOVO: Yeah.

MR. HOGAN: Yeah.

MR. COLAIACOVO: That – I'm surprised that there is a concern that you need a backup to the transmission line.

MR. HOGAN: Right.

On the Upper Churchill, the 5,400 megawatts – so can you just describe the lines that you're proposing will be built for those 5,400 megawatts?

MR. COLAIACOVO: I –

MR. HOGAN: Like, what's the route? I just want to be sure I understand.

MR. COLAIACOVO: Potentially the same – well, very similar –

MR. HOGAN: Yeah.

MR. COLAIACOVO: – to the route that has been followed for Muskrat Falls, in the sense of a link from Churchill Falls across the Strait of Belle Isle to Newfoundland, across Newfoundland and then under sea to Nova Scotia. But then, rather than going overland through Nova Scotia, New Brunswick into Maine, likely it would have to be from Nova Scotia directly to Massachusetts; otherwise, it wouldn't make sense.

MR. HOGAN: So is it realistic to think – to assume or to discuss that Massachusetts or any of these jurisdictions would want 5,400-megawatt lines?

MR. COLAIACOVO: Or some fraction thereof. It may not be the entire thing.

MR. HOGAN: Right. It's a lot of infrastructure, isn't it?

MR. COLAIACOVO: Yeah – no, not in a physical sense. In a physical sense it's just a transmission line. The – I mean, if you think about what Quebec has available that's currently carrying the power, they're actually using AC as opposed to DC. But it's a transmission corridor, right, and so this is a transmission project.

And for – you know, if you assume the continued decline of fossil fuels in the electricity system over the next 20 years, I think it's quite possible that there would be a lot of interest in getting access to that power directly. And, on top of that, as I said yesterday, even if you assume that there's lots of offshore wind and solar power that's developed in the United States, as there probably will be, having storage capacity in a system is something that's often quite valuable. And so a connection from Churchill Falls to those markets is something that I think is going to have real value for a very, very long time.

Now, it would be cheaper to go through Quebec. It's a shorter route, right? But the reality is, if for whatever reason you can't negotiate with Quebec, having an alternative route is critical. And in order to negotiate effectively, having an alternative route is critical because it –

MR. HOGAN: What about just even things like environmental permits and, you know – I mean don't you need –

MR. COLAIACOVO: Environmental permits –

MR. HOGAN: – to set all that up first before you even go to Quebec to negotiate? Is that realistic?

MR. COLAIACOVO: Well, if you'd never done it before, yes.

MR. HOGAN: But we haven't –

MR. COLAIACOVO: But you already have –

MR. HOGAN: We haven't built lines into the States yet.

MR. COLAIACOVO: That's true.

MR. HOGAN: Right?

MR. COLAIACOVO: And so you – you know, there's a whole issue of getting permits with the United States, but there have been many trans-border transmission projects.

MR. HOGAN: Have Hydro-Québec had any trouble getting approvals to build transmission capacity into the United States?

MR. COLAIACOVO: There have been a number of controversies because – typically because of objections from power industry participants in the United States who would rather not import from Quebec; they'd rather build more plants there. But there are many connections across the border.

MR. HOGAN: So just the last question I have on this BATNA – best alternative to negotiated agreement. So we've heard evidence – some people have called this project a boondoggle and we've heard evidence from a former minister of Finance of the government, who was also former chair of the board of directors of Nalcor, that the province actually shouldn't take on a project of this magnitude again. So, if that's true, do we really have a BATNA?

MR. COLAIACOVO: I think the – the question is somewhat different because in the case of Churchill Falls, there is going to be an extremely valuable asset that is already built, that's already capable of operating. And the degree of risk that you're taking in building a potential transmission line, for example, is less than in building a brand new facility like Muskrat Falls.

So would you actually be taking that risk again? Probably not, right?

MR. HOGAN: Mmm.

MR. COLAIACOVO: You know, you are taking risk in constructing a transmission line, but I think Nalcor and Emera have both demonstrated the ability to build those transmission lines.

MR. HOGAN: Okay.

All right, that's all the questions I have.

Thank you.

THE COMMISSIONER: Okay, thank you very much.

Emera Inc. is not here.

Former Nalcor Board Members – not here.

Manitoba Hydro is not here.

Newfoundland Power.

MR. HANDRIGAN: Yeah, thank you, Commissioner.

No questions.

THE COMMISSIONER: Thank you.

All right, redirect.

MR. COLLINS: Just – I'd like to confirm just to begin with. Most of the analysis you've done in your report is based on the assumptions that were made by Nalcor at the time in 2012, and it assumes those assumptions were reasonable.

So if we want to look at that analysis today, we'd have to adjust some of the assumptions to reflect – if we wanted to see how that analysis applied to us today, we'd have to adjust those assumptions to reflect the events as they have transpired. And if the Commissioner concludes that some of those assumptions were unreasonable, you would also have to adjust those analyses to reflect the changes in assumptions.

MR. COLAIACOVO: Yeah, I think there has been, for example, criticism of the load projection that was current in 2012, right? I'm not an expert on load projections; I simply worked with the material that was available because that's what would have been available at the time.

And so if that load projection was materially problematic, if it should have been different, then you'd have to recalculate, you know, all of the outcomes of the financial models to reflect that. At the time, there were various supporting documents provided by Nalcor and the government to say this is a reasonable load projection. The controversy is what it is.

After the fact, it's been demonstrated that the load projection was too high, you know, and so today, you're dealing – living with the effects of the fact that load has turned out lower. My point was just even assuming the load projection was considered reasonable, that doesn't absolve you of the responsibility of also testing what would happen if load was lower. And it does not appear that that was done in 2012 in particular.

MR. COLLINS: And so, as I understand it, you haven't provided an opinion about whether the assumptions and inputs were reasonable. The focus of your opinion is more on what type of analysis should be done with those assumptions and inputs.

MR. COLAIACOVO: That's right.

MR. COLLINS: There are a number of comments in your report on technological change. And it's been pointed out to me that inside of Nalcor's load forecast, they had what they called a technological-change variable, which, as I understand it, reflected the fact that over time, households with a comparable income level tend to use a little bit less electricity as appliances get more efficient.

MR. COLAIACOVO: Inherent in load projections is assumptions, for example, about households replacing refrigerators and stoves every 10 years. And every time you've replaced your refrigerator, it has become more energy efficient.

There is – there are energy-efficiency standards and guidelines across Canada that require the sale of products that are more energy efficient over time. And so just that – the simple working of those standards and guidelines over time has an impact on household consumption.

For example, for industrial consumption it's very similar. Elevator motors are more efficient today than they were 25 years ago. So if a building upgrades its elevators every 25 years, they're going to use less power; air-conditioning units, the same thing. So those kinds of assumptions are embedded in load forecasts typically, and, you know, professionally prepared load forecasts always take those kinds of things into account.

I was more focused on technological change on the supply side. Because if you go back to 2010, for example, and look at wind farms that were being built in Canada at that time, wind farms in 2010 were built at 80-metre hub heights with 50-metre blades at typically in the two megawatt – you know, two-megawatt class was pretty common in 2010. But even in 2010, the assumption was that that would change going forward.

And so today, typically, wind farms are being built in Canada at a hundred-metre hub heights with 60- and 70-metre blades and they're in the 3.5-megawatt class or larger. What that results in is higher efficiency, both in terms of the power that you can extract from the wind and a reduced net cost of the wind farm, right?

So when you're doing your analysis of the future and you say, well, we're going to assume that a wind farm is going to be built, you know, 10 years from now and another wind farm is going to be built 20 years after that, do you assume wind farms of the same characteristics both times, or do you assume that the wind farm the second time is going to be better than the wind farm the first time? And it's that kind of technological change that I questioned whether that was included in the planning and the scenarios.

MR. COLLINS: And could I suggest another example, just for clarity? My understanding is that Nalcor at DG3 limited the penetration of wind in the system to 10 per cent and that that 10 per cent limit was determined not by the economic limits of wind (inaudible) but by their – the experience of other isolated grids, that they had – couldn't find examples of isolated grids that had gone above 10 per cent yet. Is that another example of a technological limitation?

MR. COLAIACOVO: Yeah, and there are – I mean, you know, there's – Hawaii is often the jurisdiction that's held up in this regard. Hawaii has made a commitment to going ultimately to a hundred per cent renewable energy, of wind and solar only. It's an isolated grid; it traditionally ran a hundred per cent on fossil fuels and has been slowly changing over.

They're already well above – far above 10 per cent. I think they're already in the 30 per cent range in terms of wind and solar. So, you know, that's a limit – that's an assumption of an inability of technology to keep up with those kinds of demands.

MR. COLLINS: You mentioned in your direct that the Gull – your recollection was that the Gull Island – the unit cost of power at Gull Island was higher than the unit cost at Muskrat Falls.

And if we could go to P-00077, which was Nalcor’s submission to the Public Utilities Board, page 102, you see at the bottom of the page that “Gull Island is the larger of the two … sites. While offering more favourable economies of scale than Muskrat Falls, and therefore a lower unit cost per MWh of production ….”

So –

MR. COLAIACOVO: Happy to be corrected.

MR. COLLINS: Perfect, wonderful.

MR. COLAIACOVO: I just – I had just recalled it the other way around.

MR. COLLINS: Perfect.

You’ve – when you indicated that the Public Utilities Board had abdicated its responsibility to make a decision, can you amplify a little tiny bit the reason for that?

MR. COLAIACOVO: So the answers to these questions, which is cheaper, is never – I mean, as I said earlier, is never going to be black and white. There are always going to be scenarios in which one option is more expensive and other scenarios in which the same option is less expensive. My reading of the report from the board was that they seemed to focus on the fact that they had identified some options in which the Interconnected plan was more expensive and other options and other scenarios in which it was less expensive. And I said this means that we cannot conclude that it’s less expensive.

But in my view, the whole point of these exercises is to look at all of the available data, do analysis and then make a judgment. If you’re going to restrict yourself only to choosing options that are cheaper in 100 per cent of the cases, in 100 per cent of the scenarios, then you’ll almost never make a decision. Because in virtually any situation worth analyzing, there’s going to be overlap, right? There’s going to be uncertainty.

The future has all kinds of variables in it and so, you know, no option is ever going to be better 100 per cent of the time. If it was, then what would be the point of doing all the analysis if the choice was that obvious?

MR. COLLINS: So another way of looking at – perhaps at the Public Utilities Board’s decision is that the Public Utilities Board had been given a quite narrow mandate, not to exercise judgment about which option was better, but to answer this very restrictive question. And in order to answer that question, the Public Utilities Board had not really received the information they had been looking for. And so, if you see the – would their decision seem more reasonable if you looked at it in the light of those factors?

MR. COLAIACOVO: And that’s why I put in the caveat that given the poverty of the data which they were provided. But, on the other hand, if they were provided all the scenario data and let’s – to continue the example from earlier this morning where – let’s say there was a grid of 27 scenarios and the Interconnected Option was cheaper in 18 of the scenarios and the Isolated Island Option was cheaper in nine of the scenarios, can you conclude that the Interconnected Island Option is cheaper? Well, only if you make a judgment, right? It will – you know, it will not be cheaper in all 27 of the cases, so it requires judgment.

I’m absolutely in agreement that they, you know, were not provided all of the information that I think they should have had at their disposal. And that may be why they came to that conclusion. But, you know, the – I think the point of these kinds of exercises is to make a judgment, so …

MR. COLLINS: So, you talked about how a lot of the principles of large utility project analysis that you described are not really set out in a standard text, they’re more things people in the industry learn from experience and practice.

MR. COLAIACOVO: Mm-hmm.

MR. COLLINS: Is it fair to say that executives coming from a utility background, would – who had been looking at what other jurisdictions were doing, would probably be familiar with some of these principles?

MR. COLAIACOVO: Yeah, I think as investors, utility owners make choices every day about whether to invest in an asset or not and, you know, there are fairly sophisticated practices out there for asset management over time and decision-making about when you wanna invest in your assets and when you don't.

All we're talking about here is a much larger scale asset management question: are – you know, are – which asset option are you going to choose for your system? And given its scale, it kind of attracts the need for a lot more analysis, a lot deeper analysis than you would do for, you know, a much smaller investment. But it's only a change in quantity, not necessarily a change in type. You always have to make decisions and choices about the cheapest cost and most efficient and most sensible asset that you're going to invest in.

In the context of integrated resource planning it gets a little more complicated because you're often choosing from many different possible options. But none of this is – it's not cutting edge. It – as I said earlier, there isn't really a standard textbook for it, but integrated resource planning has basically been a developing discipline for the past 30 years.

MR. COLLINS: Is it fair to say that an executive coming from a utility background would be more likely to understand the need for this kind of analysis than a skilled project manager coming from the oil and gas industry for example?

MR. COLAIACOVO: In the oil and gas industry, project planning is extremely sophisticated and investment decisions – because in the oil and gas business you're dealing with a global liquid market as opposed to, you know, a utility environment, or even higher pressure, and so the demands for analysis are that much higher.

You know, the global supermajor oil companies invented a lot of the practices that you use in scenario planning and analysis. Scenario planning was invented by Shell Oil, right, 60 years ago. So it's – I think the – you know, it – to say coming from one industry or another industry advantages you, I don't want to speculate.

MR. COLLINS: There was some – you had some discussion about the cost of integrated resource planning. Supposing for the moment that there are jurisdictions small enough where the investment decisions to be made are too small to justify a regular integrated resource planning process, would it nevertheless be the case that if a jurisdiction of that kind were to make a single multi-billion dollar decision, that that kind of decision could justify a one-time integrated resource planning process?

MR. COLAIACOVO: Right. I think it's questionable to say that integrated resource planning is too expensive for a certain jurisdiction size because I think, you know, the exercise will be scaled to the options available. And if it's a small jurisdiction with a limited number of assets and a limited amount of demand and so on and so forth, then the integrated resource planning exercise will be scaled appropriately for that.

In this case, where you're talking about a $7-billion investment, spending money at the front end on analysis is entirely appropriate. You know, just in the context of the $7-billion capital budget, how much needs to be spent before the final decision is made to go ahead?

The development process should include all permits and approvals. It's not unreasonable that 10 per cent of the cost of the project should be spent before the full shovel goes into the – the first shovel goes into the ground, right? So an argument about costs, I think, is somewhat misplaced.

MR. COLLINS: There was some – you had some discussion about why didn't Manitoba Hydro International recommend the kind of analysis you suggested for a more typical integrated resource planning analysis. Is it possible that the short period of the Public Utilities Board review and the limited nature of the reference question are – could help explain the answer to that?

MR. COLAIACOVO: I don't know the answer to why Manitoba Hydro didn't insist on additional scenarios. I find it peculiar that they participated in a process in which some scenarios were demanded and were produced in response to those demands, and why they weren't more comprehensive in their requests. Perhaps they were more comprehensive in their requests and they just didn't get them, I have no idea. I do know, based on my own experience in

Manitoba, that many scenarios were produced. And when we asked for many more scenarios, there was some resistance –

MR. COLLINS: Mm-hmm.

MR. COLAIACOVO: – but, you know, that's a volume-and-scale issue. Having said that, you know, I can't explain the decisions made by Manitoba Hydro International at the time.

MR. COLLINS: You discussed Nalcor's analysis of waiting for 2041 as an option, the risk would be you stick with Holyrood until the early, mid-2030s and you replace it with a whole new set of assets and then you strand those assets, essentially, which costs a lot of money –

MR. COLAIACOVO: Or alternatively, replace Holyrood earlier than that, but you would still not – the replacement assets would still be stranded in 2041.

As I understood it, Holyrood could either be life-extended and reach into the 2032, 2033 time period or, alternatively, could be shut down in 2020 and replaced in 2020, in which case that replacement asset might be 20 years old as opposed to five or 10 years old. But, you know, it's still costs that would be at least partially stranded because they wouldn't reach the end of their life in 2041.

MR. COLLINS: My understanding of the way Nalcor did that analysis is that they took the Isolated Island, clipped it in 2041, and then added the cost of the Link.

Is it possible that if real resources had been sunk in optimizing the 30-year period from 2012 to 2041, that a more – that a path to get through that period that didn't involve such waste could've been found?

MR. COLAIACOVO: It's possible and I think it would've required a bunch of Strategist modelling work with different assumptions and different – you know, different drivers. I don't know. And, you know, short of recreating the Strategist models at the time and working with them, there's no way to really get an answer to that question.

I think it – the basic argument that they made that assets would be stranded in 2041 is incontrovertible, you know. Assets would be stranded, the question is: How big are those assets? How expensive were those assets? How much is that stranding, you know? What's the consequence for ratepayers, of that stranding? And so, there's, you know, potentially questions of degree, but it's fairly clear that there would be some asset stranding. The timing just doesn't fit because Holyrood is too old.

MR. COLLINS: Thank you very much.

THE COMMISSIONER: All right.

Thank you, Mr. Colaiacovo. I appreciate your time and you're free to go.

And we'll adjourn now until 2 o'clock this afternoon and we'll start with Mr. Goulding at that time.

CLERK: All rise.

Recess

CLERK: This Commission of Inquiry is now in session.

Please be seated.

THE COMMISSIONER: Okay.

All right, Mr. Learmonth.

MR. LEARMONTH: Yes, the witness for this afternoon is A. J. Goulding of London Economics.

THE COMMISSIONER: Okay.

MR. LEARMONTH: Could Mr. Goulding be affirmed?

THE COMMISSIONER: All right, Mr. Goulding, if you could stand up, please?

MR. GOULDING: Of course.

CLERK: Do you solemnly affirm that the evidence you shall give to this Inquiry shall be the truth, the whole truth and nothing but the truth?

MR. GOULDING: Yes, I so affirm.

CLERK: Please state your name.

MR. GOULDING: My name is A. J. Goulding.

CLERK: Thank you.

THE COMMISSIONER: So the A. J., does that replace something else?

MR. GOULDING: So my full legal name is Jonathan Arthur Goulding.

THE COMMISSIONER: Okay.

All right, you can be seated there, Sir.

Thank you.

MR. LEARMONTH: Okay.

I'd like to enter the following – have the following exhibits entered into the record: P-04441, P-04457, P-04458 and P-04473.

THE COMMISSIONER: All right, those exhibits will be entered as numbered.

MR. LEARMONTH: Okay.

I'm going to be – to ask that Mr. Goulding be qualified as an expert so that he can give opinion evidence in the field of regulatory economics. So I have – I'm going to go through his curriculum vitae first and then if there are any questions of counsel or the Commissioner then we'll deal with them later.

Please state your place of work.

MR. GOULDING: Yes, I'm the president of London Economics International LLC and I work out of the Toronto office.

MR. LEARMONTH: Yes, and what type of work does London Economics International LLC carry on?

MR. GOULDING: So, London Economics International, which I will refer to as LEI hereafter, is an economic and financial consulting firm focused on the energy and infrastructure industries.

MR. LEARMONTH: Yes.

MR. GOULDING: The type of work that we carry out includes: rate design, market design, transactional advisory services and strategy and litigation support associated with market and network industries.

MR. LEARMONTH: Right.

And are there offices of LEI in addition to the Toronto office?

MR. GOULDING: Yes. We have offices in Boston, Massachusetts in the US; Chicago, Illinois; we also have staff that sit in the Asia-Pacific region, along with affiliates in Australia and the UK.

MR. LEARMONTH: Now, please turn to tab 4, which is Exhibit P-04458. This is your curriculum vitae, Mr. Goulding.

MR. GOULDING: Yes.

MR. LEARMONTH: Please give us some information on your education after high school.

MR. GOULDING: I have an undergraduate degree in economics from Earlham College in Richmond, Indiana, and a master's degree from the public policy school with a focus in international business at Columbia University.

MR. LEARMONTH: And Earlham College, you're a graduate of that in 1991?

MR. GOULDING: Yes.

MR. LEARMONTH: And Columbia in New York and a master's in international business, 1997?

MR. GOULDING: That's correct.

MR. LEARMONTH: Yes.

And what – after you graduated from Columbia or perhaps even before then, please give us some indication of your employment work record. And you might want to turn to page 2 of Exhibit P-04458.

MR. GOULDING: Yes, so after my undergraduate I worked for two years for what was then known as ICF Resources in Fairfax, Virginia. Subsequent to that, I was initially on scholarship in New Delhi, India, and then was employed by the United States Agency for International Development.

After that, I did my degree at Columbia, following which I worked for Citizens Power in Boston, which was a top-10 power marketer, following which I returned to London Economics. I had been a summer associate at London Economics in – while I was at graduate school and I've been with London Economics International ever since.

MR. LEARMONTH: Yes.

And I understand that you're an adjunct associate professor at Columbia University in New York. Is that right?

MR. GOULDING: That's correct.

MR. LEARMONTH: And are you active in that role?

MR. GOULDING: Yes.

MR. LEARMONTH: So how many courses do you teach or how many lectures do you make?

MR. GOULDING: So, for the past 14 years, approximately, I have taught a course in electricity markets. In addition, I generally oversee one or two graduate workshops. That's been over the last six years. So my appointment with Columbia is for one semester a year and between one and three courses.

MR. LEARMONTH: All right.

Now, on page 2 of Exhibit P-04458 and continuing on to page 12 and perhaps beyond, there's an indication of – a statement of your work experience. I'm not going to take you through each assignment that you have referred to in those pages, but can you give us a general overview of the type of work that you undertake with London Economics?

MR. GOULDING: Certainly.

MR. LEARMONTH: I know that's a general question but just give us some feeling for the type of work.

MR. GOULDING: Of course, and it's probably useful to put this into various categories.

So, I work with both regulators and regulated companies on issues associated with rate design, particularly things like performance-based rate making, cost allocation, competitive retail market design, if that's part of a jurisdiction's overall framework. So, all of those things would fall into the regulatory bucket.

I also work with private companies, mostly private, on various kinds of valuation exercises; for example, somebody wants to buy or sell generation assets, sometimes (inaudible) assets, sometimes more esoteric things. But my role is usually to help them determine what future revenues might be within a range because that assists them in coming up with an appropriate valuation for those particular assets.

The remaining set of activities are associated with the subject matter expertise; in other words, when we're engaged in litigation support or in strategy consultations, we're engaged because we are presumed to have substantial knowledge with regards to energy infrastructure and good quantitative capabilities.

MR. LEARMONTH: All right.

The sample work experience that I've referred to you, I said it was from page 2 to 12 –

MR. GOULDING: Yes.

MR. LEARMONTH: – but it's actually from page 2 to the middle of page 19 –

MR. GOULDING: Yes.

MR. LEARMONTH: – in your curriculum vitae, just to correct that.

On page 19, you have a list of written and oral expert testimony and that goes on until page 20.

Have you ever been qualified as an expert to give opinion evidence before, either regulatory boards or courts of justice?

MR. GOULDING: Yes, I have.

MR. LEARMONTH: Can you give us some examples or …?

MR. GOULDING: Yes. I have been qualified before the Ontario Energy Board, before the Alberta Utilities Commission, before the regulator in Nova Scotia as well. In the US I have been qualified as an expert in federal court.

MR. LEARMONTH: And on how many occasions have you appeared in federal court in the United States?

MR. GOULDING: I believe three.

MR. LEARMONTH: Three?

MR. GOULDING: Yes.

MR. LEARMONTH: And in – on all those occasions have you been qualified as an expert?

MR. GOULDING: So in two of the three I was qualified as an expert. In the third, I was a fact witness.

MR. LEARMONTH: Okay.

Beginning on page 20 there's a list of your publications. So do you publish on a regular – an ongoing basis? Or has that decreased a little bit now that you're busy with London Economics?

MR. GOULDING: Well, I don't publish as much as I would like. But, generally, every one or two years I publish.

MR. LEARMONTH: Yeah.

Is it just that you don't have the time to …?

MR. GOULDING: Yes and, you know, unfortunately it doesn't pay.

MR. LEARMONTH: Right.

MR. GOULDING: So to get the time to do it, you really need to island off a block of time when you're not testifying or performing work for clients.

MR. LEARMONTH: All right.

And the speaking – your speaking engagements, I take it that you're a regular – regularly involved in speaking engagements? Is that right? That's beginning on page 21.

MR. GOULDING: That's correct.

And I note that this goes through 2017. There would've been probably one or two in 2018 as well.

MR. LEARMONTH: Okay, that aren't included in this.

MR. GOULDING: That aren't included here, yes.

MR. LEARMONTH: Yes.

Well, I'm not going to go through all the details of the CV, it speaks for itself, and all the other parties have had – have received a copy of this. So, as I said, I want to – I'm going to ask that Mr. Goulding be qualified as an expert in the field of regulatory economics. And it may be that other counsel and/or the Commissioner may have some questions for you before that formal request is made.

MR. GOULDING: Yeah.

THE COMMISSIONER: All right. Does anyone – either party – wish to cross-examine this gentleman on his expertise? No.

So, in the circumstances, I'm satisfied, that based upon the information in the witness's CV and what I've heard from him thus far, that he is qualified to provide opinion evidence in the area of regulatory economics and he will be permitted to do so.

I'm just going to make a comment to the technicians on the outside just to bring up the sound a little bit. I'm – I – at times the witness is trailing off, as is Mr. Learmonth, and I'm missing the end, so if we can just bring up the sound just a little bit I'd appreciate it.

All right, go ahead, Mr. Learmonth.

MR. LEARMONTH: Thank you.

Please turn to tab 3, Mr. Goulding, which is Exhibit P-04457, and this is your – can you identify this document on – beginning on page 1?

MR. GOULDING: Yes, I can. This is the report that I prepared regarding *Regulatory and policy issues of interest to the Muskrat Falls Inquiry*.

MR. LEARMONTH: Yes.

Turn to page 7 of that document, and paragraph 1.2 your scope of work is identified. Could you just read into the record the scope of work that you were assigned for this engagement?

MR. GOULDING: Yes.

LEI was engaged by the Commission –

MR. LEARMONTH: Now, when were you engaged, roughly?

MR. GOULDING: Excuse me, I believe I have that on page 8 in 1.3, "LEI was engaged on May 29th, 2019."

MR. LEARMONTH: Okay.

Did you have any participation, in any way, with this Inquiry before you were engaged on May 29, 2019?

MR. GOULDING: No.

MR. LEARMONTH: No.

Now, your scope of work is identified on page 7 of P-04457, there's five items, so this is – these are the specific questions that you were given. Is that correct?

MR. GOULDING: Yes.

MR. LEARMONTH: And you've organized your report to respond to each of these five topics. Is that correct?

MR. GOULDING: Yes, that's correct.

MR. LEARMONTH: Okay, and just so it will be easier for people to follow, question 1 on page 7, that's pages 11 to 32; page 2 is 25 to 32; item 3, 33 to 39; 4, 40 to 49; and 5, 49 dash 60.

Now, turning back to page 1 of your report, can you give us the broad, high-level observations that you made for each of these questions? Can you just read them into the record, please?

MR. GOULDING: Yes, did you want me to read the –

MR. LEARMONTH: Yes.

MR. GOULDING: – questions first, because I think we didn't –

MR. LEARMONTH: Okay, why don't you read the question and then go to page 1 and give your observation.

MR. GOULDING: Okay.

MR. LEARMONTH: Yeah.

MR. GOULDING: So the questions that I was asked to address were, first: How does the Newfoundland and Labrador "electricity regulation system compare to other comparable systems?" Does the "system of legislation and regulations adequately cover both sale of electricity to" provincial "ratepayers and to others?"

The second question was is –

MR. LEARMONTH: Okay, now, let's just go back to page 1 –

MR. GOULDING: Sure.

MR. LEARMONTH: – and give your observation on that now.

MR. GOULDING: Of course.

MR. LEARMONTH: Okay.

MR. GOULDING: So the response was that, while the "*system of electricity regulation shares many characteristics with other Canadian provinces, some aspects may need to be updated to adequately address sale of electricity to those who are not ratepayers* …."

MR. LEARMONTH: Okay. And then we'll go back to page 9 and, in the same order as we did before, deal with points 2 to 5.

MR. GOULDING: Yes.

So the second question is: "Is NL's system of regulation adequate to deal with the new challenges that arise after interconnection, including energy marketing? Does it meet the needs of current players in our electrical system including ratepayers, and if not, what changes should be made?" The high-level response was that "*issues arising due to interconnection, including reliability standards, open access, and energy marketing, require additional consideration, particularly with regards to aspects such as risk management* …."

The third question was: "Should environmental considerations be made part of the Province's energy policy?" The summary of our response is that "*environmental considerations should be incorporated into the Province's energy policy, and supported through an ongoing inter-ministerial working group* …."

The fourth question was: "At a high level, how effective is the current electricity pricing model, and should any changes to it be considered? Is it appropriate to continue to set rates for consumers of electricity on a cost of service basis or is there another more appropriate basis to set rates?" The summary of our response is that "*NL should explore moving beyond cost of service ratemaking to address both performance expectations and the role of non-utility distributed energy resources* …."

The fifth question: "Is there likely to be any role for renewable energy generation expansion in the coming decades, either for internal use or for export?" And the summary of our response is that "*there is a limited role for renewable energy generation expansion in the coming decades, particularly for export; the primary focus for renewables should be on combining them with storage for isolated systems.*"

MR. LEARMONTH: Okay, thank you.

Please turn to page 8 of your report and take us through the – what you have to say. I note that you first identify that after being engaged on May 29 you answered these five questions and that this was a very high-level review of the subject matter, is that correct?

MR. GOULDING: Yes, that's correct.

MR. LEARMONTH: Okay, and what exactly do you mean by high level?

MR. GOULDING: Well, as we note in the report, each of these five questions could be the subject of a separate, multi-month investigation.

What we put together was consistent with the scope and the time that was available. This has involved review of what we viewed as being key documents. That is not to suggest that there may not be other key documents out there that could pertain to these topics, but rather that we identified certain key documents that we felt were important or useful for our opinion. But our opinion is not intended to address every detail related to each of these topics.

MR. LEARMONTH: All right.

Now, just take us through, in summary form, your – what you found in – on – with respect to the background on the NL electricity sector. That's starting on page 8 of your report, P-04457.

MR. GOULDING: Of course.

So, commencing with section 1.4, and I would note that the reason that we organized the report like this was that this background is then referenced in future sections.

MR. LEARMONTH: Yes.

MR. GOULDING: So, the province is primarily served by two utilities: Newfoundland and Labrador Hydro and Newfoundland Power. We note that Newfoundland and Labrador Hydro is wholly owned by Crown corporation Nalcor Energy, while Newfoundland Power is an investor-owned utility. Both are vertically integrated utilities but NLH's operations are weighted towards generation transmission, while Newfoundland Power's operations are inclusive of delivery.

Furthermore, Newfoundland Power purchases over 90 per cent of its energy requirements from NLH, while generating the remaining amount with its own facilities. There are nine utility generators. We'll sometimes use the term IPPs –

or independent power producers – as well, who supply energy to these utilities.

We've provided some high-level market indicators focusing on population, population density, GDP growth, installed capacity, noting that there's currently – excluding Churchill Falls – approximately 2,000 megawatts of installed capacity for a peak demand on the IIS of approximately 1,700 megawatts and that, historically, load growth was 1.3 per cent over the past decade. We note in later parts of the report that that is expected to further slow and we emphasize the number of customers. And as we get to later sections of the report, these are presented to provide some context to the relative size of Newfoundland and Labrador, relative to other provinces.

If we move to page 9, we provide a graphical overview of both the installed capacity by type. Installed is, as we can see, dominated by hydro but formal, particularly oil-fired generation, has played an historic role. We see that the vertically integrated nature of the system means that both utilities operate across all aspects of the value chain engaged in generation, transmission, distribution. And we have the regulator, the Board of Commissioners for – of Public Utilities.

So, as we continue on, when we think about generation we put Churchill Falls in a separate bucket; approximately 5,000 – 5,400 megawatts at Churchill Falls. We also reference the Muskrat Falls Project, adding an additional over 800 megawatts of generating capacity and then we discuss the existing generation portfolio. As I've noted, a little bit over 1,700 megawatts.

So, moving to transmission, we have 4,400 kilometres of transmission lines at NLH and the system here was isolated up until 2018; is increasingly integrated as the transmission comes online. And as a consequence, there are a number of issues which we discuss in the report.

And then finally, both utilities do have some distribution responsibilities. NLH owns over 2,700 kilometres of distribution lines, reaching almost 39,000 customers. NP reaches 268,000 customers.

MR. LEARMONTH: Okay.

Okay, next turn to the first question that you were asked to cover in your scope of work, the question being: How does the electricity regulation system – "*How does NL's electricity regulation system compare to other comparable systems? Does NL's system of legislation and regulations adequately cover both sale of electricity to NL ratepayers and to others?*"

So just take us through, give us an overview of the comments that you make in answer to this question.

MR. GOULDING: Certainly.

So, in order to answer the question, we broke it down into its components; this is something that we've done for the subsequent questions as well. We started by thinking about, well, what do we mean by an electricity regulation system? And we've defined that as being "a set of laws, institutions, and regulations which govern … production, transmission, distribution, and sale of electricity."

Furthermore, those arrangements may include both monopoly and competitive aspects. Examples of the types of institutions that we mean include policy-setting bodies, such as ministries, and rate- and standard-setting bodies, such as regulators. And there may be specific regulators for standards that are distinct from those that set rates.

So after defining what constitutes an electricity regulation system, we then move to thinking about what are the components of such a system here in Newfoundland and Labrador?

We started with the laws, focusing specifically on those that empowered the regulator. So the *Public Utilities Act* of 1990 and the Electrical Power Control Act of 1994 were both major pieces of legislation that guide the power sector. However, there have been a number of specific laws and regulations which also impact the sector, including, in particular, some of the amendments that occurred to facilitate financing for the Muskrat Falls Project. And among the purposes of those amendments were to provide NLH with the exclusive right to supply and sell electricity to retailers and industrial customers in the IIS. We've also provided a timeline of this key legislation.

When we turn to the relevant institutions, we've divided institutions between policy-setting and regulatory agencies, so the Department of Natural Resources being identified as the policy-setting body specific to the electricity sector, and then the PUB as being focused on – we sometimes refer to as economic regulation, the setting of rates.

Now, when we move to regulations, I'm not going to go through the list of regulations here, but we've highlighted a few of the specific regulations simply to demonstrate that they exist.

MR. LEARMONTH: That's on page 13, the box in –

MR. GOULDING: I apologize, yes, that's on –

MR. LEARMONTH: Yeah.

MR. GOULDING: – that's on page 13.

MR. LEARMONTH: Yeah.

MR. GOULDING: So through regulations, the regulator fills in the details, if you will, under the guidance of its mandate consistent with legislation.

So if we turn to page 14, after defining generally what electricity regulatory system is, and highlighting the aspects of that regulatory system here in Newfoundland and Labrador, we then turn to the question of how do we define comparable systems. And this is an area where some judgment is required. We have chosen to focus on Canadian provinces that have a number of customers equal to or greater than those here in Newfoundland and Labrador.

Now, we note that this means that we are taking into account provinces with more than 10 times as many customers, but the overall set of arrangements we find to be relatively similar across provinces. And we also think it's important to use as comparables, for the purposes of regulatory systems, those jurisdictions that operate under similar governmental arrangements.

Because Canadian provinces operate under a parliamentary system, this means that there are differences in the ability to establish institutional independence. And it's also important to note that the procedural history in Canada is shorter from a regulatory perspective than it is in, for example, the United States, where some regulators go back a century or so. And so this – you know, starting with, let's say, two decades' worth of experience can lead to different outcomes.

So we chose as comparable systems those that were – that had a number of customers that was equal to or greater than those in Newfoundland and Labrador, while acknowledging that if you have 10 times more customers, you have 10 times more resources, and that may justify a larger regulator doing different things than you would have in a smaller jurisdiction.

I'm going to go through the other provinces at a very high level; I'm not going to present every detail. One of the primary distinctions among provinces in Canada is the extent to which market mechanisms are used. Alberta is the Canadian jurisdiction that makes the greatest use of market mechanisms with regards to generation, and that means that it has different institutions, additional institutions.

And so in addition to having the policy entity in the department – the Alberta Department of Energy – and the regulator, who's gone under various names – currently the Alberta Utilities Board – you have the AESO, the Alberta Electric System Operator, which serves as the independent system operator. You have, as well, a Market Surveillance Administrator, whose function is to determine the extent to which the wholesale market for generation is competitive.

MR. LEARMONTH: Can I just –

MR. GOULDING: Sure.

MR. LEARMONTH: – interject for a minute? This competitive system that you're describing in Alberta, is that similar in some ways to the systems that operate in the States – of the United States?

MR. GOULDING: Yes, it's –

MR. LEARMONTH: More so than other Canadian provinces?

MR. GOULDING: It's quite similar.

MR. LEARMONTH: Okay.

MR. GOULDING: The only other Canadian province that has some degree of a competitive wholesale market is Ontario, and when I talk about Ontario, we'll talk a little bit about the differences there.

MR. LEARMONTH: Okay.

MR. GOULDING: But Alberta is probably the closest among the Canadian provinces to those US jurisdictions, like New England and New York, which have competitive wholesale generation markets.

MR. LEARMONTH: Okay, thank you.

MR. GOULDING: Alberta has another institution, which is unique, referred to as the Balancing Pool. The Balancing Pool essentially manages residual obligations of ratepayers. It's not something that's found in other jurisdictions.

We will see a pattern as we go through the provinces. We see that there is an *Electric Utilities Act* in Alberta, as well as something called the *Hydro and Electric Energy Act*; and the *Electric Utilities Act* relates not only to AESO, but to the overall arrangements of the Alberta competitive electricity market, but we also see that the AUC is grounded in an act, the *Alberta Utilities Commission Act*.

Now, when we turn to exploring regulations, what we'll see is that, you know, in Alberta, because of the market structure, you will have different regulations. And so, you will have regulations that establish the way in which the competitive electricity market operates; regulations which in particular focus on retail competition and on how small customers, those that don't wish to switch, are served. But in addition, on the traditional monopoly side of the business, on the wire side, Alberta, along with Ontario – in fact, Ontario was a leader in performance-based rate-making, or PBR as we call it – Alberta followed along a few years later – but Alberta has in place a full-scale performance-based rate-making system.

So, in addition, one thing to note about Alberta is that a premise for having a competitive electricity market is that you've got multiple sellers, so there are multiple generators in Alberta. They are, for the most part, unbundled from wires, so the generators do not own any wires, with one exception. Sorry, let me rephrase that. The former municipal utilities, municipally owned – ENMAX, for example, owns both generation and wires – but other large generators do not.

So, in Alberta you're going to find more generators than you find in many other provinces, and they are earning their revenues from the competitive wholesale market rather than through long-term power purchase agreements.

So, as we move to British Columbia, in British Columbia you have a dominant, vertically integrated Crown-owned corporation that supplies a significant amount of the province's power. There is one privately owned vertically integrated utility, as well, in British Columbia, but we see the same sets of institutions. We see a ministry – in this case the Ministry of Energy, Mines and Petroleum Resources – that develops policies for the energy sector and we also see a regulator. So the BC Utilities Commission serves as the regulator for British Columbia, and over time it has had varying power over the Crown corporation.

We see the same sets of laws. We see the *Utilities Commission Act* that governs the regulator; we see the *Hydro And Power Authority Act* which governs BC Hydro, and we see the *Ministry Of Energy And Mines Act* which governs the ministry.

When we turn to regulation, British Columbia is interesting because they have instituted performance-based rate making for the privately owned entity – and that's evolved in various flavours over time – while setting rates for BC Hydro on a cost-of-service basis.

Yes, apologies, I'm on page 17 moving to page 18.

So we do see some use of the different resource plans in British Columbia as well. The recent review of BC Hydro has resulted in a return to the regulator of some oversight and decision-making authority. And the regulator, henceforth, will have the ability to review and make decisions on BC Hydro's costs, rate increases and regulatory accounts, programs and capital projects.

MR. LEARMONTH: Okay, just before you leave –

MR. GOULDING: Yes.

MR. LEARMONTH: – that – BC, you've referred to the fact that BC Hydro is required to file integrated resource plans. And could you just give us a brief description of what an integrated resource plan is and how it works with the concept of conservation and demand management – just an overview of that.

MR. GOULDING: Yes.

So in an integrated resource plan, a vertically integrated utility that is traditionally regulated is required to submit a document, which usually goes out over a planning horizon of often 10 to 20 years, which is intended to show that the utility has made a good-faith effort to consider a wide range of reasonable alternatives for meeting potential load, as well as examining a range of potential load forecasts.

And the IRP itself should be neutral with regards to technologies and ownership of resources. The objective is to identify the reasonable least-cost portfolio that is responsive to a range of plausible alternatives.

You asked about conservation and demand management. The reason that it's called an integrated resource plan is that demand management is intended to also be considered a resource. And so, in theory, if the levelized cost of meeting an additional hundred megawatts of load is $50 per megawatt hour and you could pay people $45 per megawatt hour not to consume, then that would be a better outcome for the system.

And so the utilities are required to – utilities that submit integrated resource plans are required to think about load management as a resource.

MR. LEARMONTH: Okay.

Now, is this integrated resource planning with the CDM – a component of it I guess you would say.

MR. GOULDING: Mmm.

MR. LEARMONTH: Is that something that is used, you know, in most jurisdictions, in some jurisdictions, in both Canada and the United States, or is it a rare occasion where we see a jurisdiction which requires integrated resource plans to be filed?

MR. GOULDING: So, you first have to distinguish between the jurisdictions that have vertically integrated utilities than those that don't. So –

MR. LEARMONTH: We have – Newfoundland and Labrador has –

MR. GOULDING: Yes.

MR. LEARMONTH: – a vertically integrated –

MR. GOULDING: Yes.

MR. LEARMONTH: Yes, yeah.

MR. GOULDING: Yes, that's correct.

MR. LEARMONTH: Yeah.

MR. GOULDING: So, in jurisdictions that have gone to a competitive wholesale market, then it's up to the market to determine the optimum mix of resources for the future, and usually conservation and demand management competes through a variety of programs that may be administered by an AESO.

MR. LEARMONTH: So that's a market driven – that's –

MR. GOULDING: That's –

MR. LEARMONTH: – driven by the market –

MR. GOULDING: Market driven –

MR. LEARMONTH: – not by anything else, yeah.

MR. GOULDING: That's correct.

MR. LEARMONTH: Right.

MR. GOULDING: But in the parts of the United States that remain vertically integrated, regulated, it is quite common. Indeed, I would argue that it is considered best practice for the regulator to require an IRP to be submitted.

Now here in Canada, we see – and I believe if we go to page 25, we have a table in figure 6 that talks about, in particular, the regulator's role with regards to IRPs. Alberta, because it has competitive wholesale market, there's no IRPs. As mentioned, it's intended to come into place in BC. There's not one in Manitoba; being considered in New Brunswick. There is one in Nova Scotia. Ontario is fully unbundled and so integrated planning is something that, in past, has been done by the ministry rather than by the individual companies. And in Quebec, because Hydro-Québec is vertically integrated but unbundled, the distribution entity does do integrated resource planning from a procurement perspective, and IRPs are being considered in Saskatchewan.

MR. LEARMONTH: Okay, so then we can continue on, on page 18, with Manitoba, a summary, a brief summary of the system institutions, laws and regulations in Manitoba.

MR. GOULDING: So, in Manitoba we have policy that is set within the Department of Growth Enterprise and Trade, specifically by the Energy Division within it. We have a Crown corporation which is somewhat unique among the Crown corporations in the power sector also includes the natural gas utility. We have a regulator, the Manitoba Public Utilities Board, whose responsibilities are more limited than regulators in other jurisdictions.

The PUB in Manitoba does not have the ability to provide oversight on utility's capital expenditures; however, the regulator may be called upon to provide recommendations and observations with regards to the capital development plans.

So, these kinds of structures can sometimes set up a bit of a tension where the regulator approves the rates, but not the capital expenditures, which you end up with some potential for the regulator to have some de facto authority because, otherwise, the utility doesn't recover what it needs in rates.

Now, the laws, again, we see the same structure. The *Manitoba Hydro Act* governs Manitoba Hydro. We see *The Public Utilities Board Act* which guides the PUB, and Manitoba is under a cost-of-service regime.

Moving to page 19 and looking at New Brunswick, the institutions, we have the ministry of Energy and Resource Development and, within it, the department of Energy and Mines, which develops policies associated with the electricity sector through its Energy branch. We, again, have a Crown corporation that is a vertically integrated electric utility. There are also three municipal utilities in New Brunswick.

Again, we see an *Electricity Act* that guides rate applications. We see a general rate application that's submitted annually and an IRP that's submitted every three years.

Moving to Nova Scotia. In Nova Scotia, we see the Department of Energy and Mines serving as a policy entity. The main utility is private; it's the former Crown utility. It is vertically integrated, investor-owned, the UARB is the regulator.

So, again, we see a *Public Service Act* that sets the parameters for the policy-making entity. We then see the *Public Utilities Act* for the UARB, and you'll note the capital expenditure threshold for capital expenditure in excess of $250,000.

So, with regards to regulations, we then see annual capital expenditure plans that are submitted. We see integrated resource plans with a 25-year outlook. We also see some feed-in tariff programs that have been in place since 2011.

Now, moving to Ontario. Ontario's structure is a little bit different. As I mentioned, Ontario does have a wholesale market. The – however, the bulk of generation in Ontario, while the wholesale market effectively serves the balancing function, most entities in Ontario receive their revenues through either long-term contracts or regulated arrangements.

The largest generator continues to be provincially owned. The largest transmission company, which is also a distribution entity, has been partially privatized, and there are 60, approximately 60 distribution entities, mostly municipal owned. That's down from well over 200 municipal distribution utilities that existed approximately two decades ago.

So, as in most provinces, the names of the ministries have evolved. Currently, the policy-setting entity is the Ministry of Energy, Northern Development and Mines. There is an independent system operator, the Independent Electricity System Operator, and then the regulator is the Ontario Energy Board, the OEB. We do see just – I mentioned the balancing pool in Alberta – in Ontario, there is a residual obligations entity, the Ontario Electricity Financial Corporation, which manages some legacy NUG contracts. So, those are the key institutions in Ontario.

When we think about the various laws that guide them, we have the *Ministry of Energy Act, 2011*; we have the *Electricity Act* of 1998 which has been amended several times; we have the *Ontario Energy Board Act*, also of 1998, which guides the OEB; and there have been a number of other pieces of major legislation which have influenced the sector. These included the Green Energy Act in 2009 as well as, more recently, acts that are intended to restructure the Ontario Energy Board, restructure the regulator. The focus of that act is to separate the operation, the day-to-day operation of the regulator from the quasi-judicial aspects of its role so that those that are guiding rate cases are not also the same people that are managing the agency.

Now, Ontario has also instituted performance-based rate-making. Ontario was a pioneer in this respect, they've had a form of performance-based rate-making since around the year 2000. They've gone through – we'll refer to the period over which a particular set of arrangements is in place under PBR as being a generation, so Ontario's gone through four generations of PBR and is in the process of thinking about how to further update its system to respond to innovation and distributed energy resources.

Moving to Quebec, we, again, see a similar structure. We see the ministry being responsible for policy, we see Hydro-Québec, again, vertically integrated wholly owned government utility, but Hydro-Québec is fully unbundled such that the various parts of the value chain relate to one another within the company, with pricing that's specific to that aspect of the value chain. And so when we talk about unbundling, that means that generation has its own cost structure, transmission has its own cost structure, distribution has its own cost structure, there's an understanding of how assets and employees are assigned to those buckets, and you have some degree of transparency with regards to transfer pricing within the entity. So that's what I mean by unbundled.

So, we see the Régie, the regulatory agency. As well, we see similar categories of laws, we see the *Hydro-Québec Act* and we see an *Act Respecting the Régie*, very similar to the names and types of acts that we see elsewhere. Regulations continue to evolve. Currently, there is legislation which could institute a potential rate freeze in Quebec and – also regulatory filings on a periodic basis.

Now move to Saskatchewan. When we think about Saskatchewan, again, we have a province that's relatively small in the number of customers but vast in terms of its land expanse. We have the vertically integrated utility, SaskPower, which has an exclusive franchise except for distribution in two cities. There is a Rate Review Panel which reviews rate proposals by the utility, provides recommendations to the government.

So, what we do see is a different structure in Saskatchewan where the Crown Investments Corporation, which is the owner of SaskPower, also has the authority to approve rate changes and major investment decisions. So, Saskatchewan kind of hearkens back to an earlier day in Canada when the Crown corporations were largely self-regulated, although there's more transparency in Saskatchewan than there used to be with regards to these matters. SaskPower is responsible for developing an integrated resource plan, the latest one was in 2017. Otherwise, it's largely a cost-of-service regime.

So, we then move to the question – having described at a very high level the regulatory system, legal system, institutions in the various provinces, to think about how does the system of electricity regulation here in Newfoundland and Labrador compare to these comparable systems?

So, when we look at it on a very high level, there are a number of things that are comparable. There is a delineation between the policy entity and the regulatory body. There are laws that establish the role for the policy body and for the regulator. Where provincially owned entities exist, they have been corporatized, they are not government departments, they are professionally managed. Processes for establishing rates are set forth in regulations. So we see that as a commonality, really, across all the comparable provinces.

Now, where the provinces differ is, you know, we see differences in the role of the market, we see differences in the extent of alternatives for customers, integrated resource planning is something where it's applied with different degrees of formality across the provinces, as well as the role of the Consumer Advocate. Now, as I mentioned in the description of British Columbia, we have seen over the past, let's say, 15 years – we initially saw governments removing authority from regulators to approve large capital projects, and we've now started to see that pendulum moving back to re-establishing, in particularly in British Columbia, the ability of the regulator to review and approve or deny such large projects.

The regulators in Ontario and Alberta are really starting to look at issues with regards to innovation in terms of thinking about is the electric power system always going to be organized on the basis of central generation that is sent out through high-voltage transmission lines, step down to distribution voltages and distributed to customers, or are there going to be other arrangements that arise with the proliferation of distributed energy resources? So these are issues that are perhaps only starting to be explored in Newfoundland and Labrador but that other provinces have been exploring in greater depth.

So moving to page 26: Does the regulatory system adequately cover sales to ratepayers? And to consider this question, we looked at previous work that had been done for the Department of Natural Resources with regards to, you know, potential shortcomings. And so in a 2015 report, Power Advisory LLC identified areas that the authors felt deviated from best practice, and so they had a list, this is an excerpt from that list. So the concept of being more clear with regards to how to set rates and review proposed projects to make sure that the public interest test is well defined; employing outcome-based policy directions; assessing the need for new facilities and cost-effectiveness of the alternatives; requiring integrated resource plans of all utilities; increasing the filing thresholds from the low levels that they're at today; addressing the Rural Deficit Subsidy; and timely rate review processes.

So as we look at the record since 2015 we have not found substantial evidence that these shortcomings have been fully addressed. So one of our observations with regards to whether the regulatory system adequately covers sales to ratepayers, is that these issues do need to be addressed. And so – and it's clear that there are constraints, right? Some of these are actually established in the law. This is a degree of specificity with regards to filing thresholds, which is unusual to find in the law. Normally that would be something that the regulator would have some discretion on determining what the filing limitations should be.

But we note that not all of these issues are unique to Newfoundland and Labrador. The issue of timely rate review processes is something that is challenging for almost every regulator and is driven by, you know, how many staff they have, the number of intervenors, the complexity of the process. So – but that doesn't mean that the issue shouldn't be addressed. You know, one of the observations that we make is that, you know, Ontario's rate handbook provides strong guidance to entities that are filing – that are filing applications and, you know, such guidance is helpful.

MR. LEARMONTH: Yeah.

Yeah, just to –

MR. GOULDING: Yes.

MR. LEARMONTH: – before you move on, you say that your review indicates that there is – or suggests there's little progress been made on most of the recommendations. It's possible they are, but you didn't find them. Is that correct?

MR. GOULDING: That's correct.

MR. LEARMONTH: You don't know about them.

MR. GOULDING: Yeah.

MR. LEARMONTH: But are these concerns that – assuming that these recommendations have not been followed, is that an item of concern to you or are these unimportant matters that don't really cause you any concern?

MR. GOULDING: There are varying degrees of concern, so outcome-based policy direction is important because it doesn't determine the solution before you ask the question. In other words, if you start with the premise that geothermal power is good and therefore should be encouraged, then you're determining the solution, whereas if you say the outcome that we wish to achieve is increasing zero-emitting resources, you are not saying we must have geothermal power.

And so the failure to use outcome-based policy direction can prevent or can impede finding the least-cost solution based on your policy objective. So, you know – and that can be very material. Likewise, the ability to have proper review of large-scale capital projects that will be paid for by ratepayers, I think we believe is essential to providing the appropriate balance between the initiatives that are set forth and independent oversight.

So, when we look through this, outcome-based policy direction, review of large-scale capital projects, integrated resource planning are all elements that have a material impact over the long run.

MR. LEARMONTH: Okay.

MR. GOULDING: It's not that the others aren't important, but the others are more about process.

MR. LEARMONTH: Okay, thank you.

So, next on page 26, 2.5.2, are there any other aspects which should be considered?

MR. GOULDING: So I've already touched upon review of large-scale capital expenditures. The other area is that customer choice is not necessarily something that will be able to be wished away over the long term, and that's particularly the case as delivered prices to consumers rise. Consumers will begin to look for other alternatives, and it will be important to be proactive in thinking about how the province is going to deal with that.

We've also provided some examples about how regulators that do have the authority to review capital expenditures have treated them. We've provided an example from the US, in Mississippi, where a particular power project went significantly over budget. The cost overruns were ultimately disallowed from rates, and the utility that had proposed the project ultimately took a substantial writeoff.

MR. LEARMONTH: Hmm.

MR. GOULDING: So regulators around the world have different ways of dealing with cost overruns in the context of a – capital expenditures that are added to rate base, and it's important to give regulators tools that provide for reasonable oversight.

MR. LEARMONTH: Okay, so that's on page 27.

MR. GOULDING: Yes.

MR. LEARMONTH: Now, 2.6, can you give us a brief summary of your findings under the heading, Does NL's regulatory system adequately cover sales to others? Just a high level, please?

MR. GOULDING: Of course.

So it's important to understand the distinction and impact. So the regulatory system should be primarily focused on things that impact ratepayers. So if there are sales that have no impact on ratepayers, then generally the regulator need not be involved. But in the event that ratepayers are adversely affected, then the regulator does need to have authority to disallow such contracts.

Furthermore, one of the important elements is to assure that system costs are appropriately allocated between existing ratepayers and export customers. And so we believe that this is an area that needs to be carefully delineated so that in the future, particularly in instances where the ratepayer doesn't have any claim on the profits from export sales, it is critically important that the cost of transmission of those exports be charged to the entity that is earning the profits.

MR. LEARMONTH: Okay, and you've given examples on page 28 and 29 of different provinces which serve to illustrate that point. Is that correct?

MR. GOULDING: That's correct.

MR. LEARMONTH: Yeah.

MR. GOULDING: So we give examples from British Columbia and Manitoba –

MR. LEARMONTH: And then the approach in – 2.6.3, Approach to system cost allocation for exports in Newfoundland and Labrador, can you touch on that please?

MR. GOULDING: Sure.

So we believe that the appropriate approach for Newfoundland and Labrador would be to use the Open Access Transmission Tariff and to appropriately allocate the portion of system costs that are caused by exports to those exports. We believe that that approach is transparent, provides for better accounting and economic decision-making.

THE COMMISSIONER: (Inaudible.)

MR. LEARMONTH: All right. And then the –

THE COMMISSIONER: So just – can I just – so in our situation here now, I mean, you're familiar with Muskrat Falls and the fact that we have a PPA.

MR. GOULDING: Yes.

THE COMMISSIONER: And so the ratepayers of the province are required to pay basically the full costs –

MR. GOULDING: Yes.

THE COMMISSIONER: – of the power that's generated, and that includes power that could be sent to export.

So how would this apply to that?

MR. GOULDING: So on an ongoing basis, I would argue that the cost of the transmission system, that there should be a charge for every kilowatt hour that's exported that is directly associated with the costs of transmitting that power out. So in that sense, the power that's exported would be paying the transmission charge that would cover its use of the facilities.

THE COMMISSIONER: Okay, so the customer then pays for transmission?

MR. GOULDING: Well, if we think about the export – if we think about export as being an additional customer –

THE COMMISSIONER: Right.

MR. GOULDING: – right –

THE COMMISSIONER: That customer, I mean.

MR. GOULDING: That customer would pay for the transmission separately.

THE COMMISSIONER: Okay.

And how – so is that something that's added to the price of the export, or is that included in the price or …?

MR. GOULDING: So when we think about exporting, then the – your target profit, if we – let's say that the price in New England is $45, right, and the transmission charge is $8, right, then you would net back to the exporter $45 minus $8, right, so you would end up with $37 net to the exporter.

THE COMMISSIONER: And the $8 would go where?

MR. GOULDING: Would go to the – if we think about the rate base, right, you've got the cost of rate base divided among customers. So while the costs go to – if we think about the way that it's organized elsewhere, in fact, you'd pay that into the system operator; the system operator would give it to the transmission entity – the owner of the transmission assets. But what that then means is that the other customers are paying less because the export customer is paying for their share of the transmission system.

THE COMMISSIONER: All right, okay.

MR. LEARMONTH: Okay.

Okay, just to conclude this topic, 2.7 on page 29. Can you give us a summary of the consolidated response to the adequacy of the regulatory system? And then we'll move on to the next topic.

MR. GOULDING: Certainly.

So while the electricity regulation system in Newfoundland and Labrador has elements that are similar to those of comparable systems, there are some shortcomings that have been previously identified that remain to be fully addressed. We believe that the system of legislation regulations does adequately cover sales to Newfoundland and Labrador ratepayers but should further empower the regulator, particularly with regards to large capital project approvals.

When we turn to the question of sales to others, there's a need to assure that the regulator has the authority to approve or deny an export sales contract, which has an adverse impact on ratepayers, and that transmission costs are appropriately allocated between exports and domestic ratepayers.

MR. LEARMONTH: Okay. Thank you.

Now, we're on page 30 and the –

THE COMMISSIONER: Just before we do, I just have one more question, I apologize.

MR. LEARMONTH: Sure.

THE COMMISSIONER: So, when would a situation arise where – or can you give me an example of the situation that might arise wherein the sale to – or the export would, in fact, impact the ratepayer?

MR. GOULDING: So, I'm going to discuss potential future situations. I'm not going to discuss something that would be specific to the Muskrat Falls arrangements.

But if we imagined something in the future where an export were to have free use of the transmission system that others have paid for, and there's no benefit that accrues back to ratepayers, and that export caused congestion in the system. That would certainly be something that was an adverse impact to ratepayers.

THE COMMISSIONER: Okay. Thank you.

All right. Good. Thank you very much.

MR. LEARMONTH: Okay. Thank you.

Page 30. The question is, "*Is NL's system of regulation adequate to deal with the new challenges that arise after interconnection, including energy marketing? Does it meet the needs of current players in our electrical system including ratepayers, and if not, what changes should be made?*"

Could you take us through your review of that topic, please?

MR. GOULDING: Certainly.

So, we started by thinking about the criteria to assess adequacy of regulation, and we started by saying that to be at least adequate, we would want to see institutional frameworks that are similar to those that are in place in other jurisdictions, but which take into account the size and unique position of Newfoundland and Labrador in the electric power grid.

So, when we say the minimum institutional framework, what we essentially mean are: Are there institutions that are devoted to looking at reliability? Are there institutions that are looking at day-to-day operation of the grid; are those institutions transparent, operating under particular rules? So – and as we go through we talk a little bit more about what those institutions are.

So we then said, well, what are the new challenges that arise as a result of interconnection? And we go through them. One is that in becoming integrated you also become integrated either in fact or in effect with large institutions over which you have limited control. And so among those are the US Federal Energy Regulatory Commission, the North American Electric Reliability Corporation and the Independent System Operators in the export markets.

Not suggesting that these entities have specific jurisdiction within Newfoundland and Labrador, but rather what we're saying is that these institutions have a direct impact on your export revenues and they require significant attention with regards to monitoring developments and to the extent that your activities touch areas where these entities have jurisdiction, you then start to have compliance issues and compliance monitoring.

So we'll talk about challenges from power marketing in a minute. But interconnection means that you have greater participation in regional planning, exposure to US Federal and ISO rules, NERC standards – and some of these standards are becoming quite detailed – things like cybersecurity, for example. And so there are things that you might do that make sense when you're looking at, you know, what's effectively a 3000 megawatt system, that are not allowed in a, you know, over a million megawatt system. Right?

So then, if you are participating in those markets then you need to understand those rules and regulations and standards and you may need to seek exemptions if the standards or the thresholds are difficult or costly to achieve. So, when we then turn specifically to energy marketing there are a number of aspects in addition to the compliance and planning issues that I have already mentioned that need to be considered.

Now, generally speaking the practice is that if you are going to be engaging in a substantial amount of trading you need to set a up a subsidiary that's going to house that, you need to staff it, right. So we've seen, for example, Nalcor Energy marketing being established here that follows in the footsteps of, you know, British Columbia which has Powerex, and you have Québec which has a well-established operation in the US. Even New Brunswick has a separate energy marketing entity.

But setting up the legal entity is just the first step; there are a number of other staffing and resourcing decisions that need to be made and monitored. And that becomes much harder in smaller organizations because you know one of the most important things when you engage energy marketing is to have strong risk management and compliance functions. If you have a relatively small operation, your ability to fully separate those activities becomes more difficult because you may not have the resources to have the appropriate number of staff, and also in a small organization, the tension that's required between the risk management and compliance focus on one side and the trading focus on the other, can be difficult to maintain.

So, in addition, energy marketing requires the ability to post credit. This means that you need to look at how much credit do you need to maintain as required by your counterparties, and if you're active directly in various independent system operators, they will also require a certain amount of credit. The harder it is for you to post credit, the harder it is going to be to hedge, and that can circle back into an increase in risk, which in turn makes credit less available.

So, the risk management function needs to be clearly set out, it needs to be staffed independently of the trading function, and it requires clear and consistent reporting, and it really requires, from the very top of the organization, a mandate that, you know, we're going to place risk management at the core of what we do. So it needs to even go up to the board level, concepts like the ability to calculate the value at risk, avoiding credit concentration and assessing counterparty risk are all essential.

Now, we've got internal risk managements associated with trading, but there's also compliance, and what we've seen is that, you know, even relatively small entities can be drawn into substantial compliance issues in the US once you begin trading there. And so those can go from just the fact that you need to obtain market-based rate authority from the US Federal Energy Regulatory Commission, through to for those that are engaging in more complex trading operations, the potential risk of being accused of market manipulation.

So – and we want to emphasize – the question was: What are some specific challenges that energy marketing poses? The question was not whether these challenges have been fully addressed within Nalcor. So, we're not suggesting, necessarily, that Nalcor hasn't addressed these issues, but we are emphasizing that they are important and must be part of any oversight checklist.

So, then we turn to the question of the needs of current players in the electrical system. We've defined those current players as being ratepayers, utilities, IPPs and industrial consumers, who, of course, are also in the ratepayer category, and policy-makers themselves.

So, what we've said was that these stakeholders need to be confident that the complexities of interconnection are being managed, that consequences are well understood, that interconnections are being operated in a least-cost and non-discriminatory manner, and that appropriate information related to the interconnections is publicly available.

So, in assessing which needs are not met by the current regulatory system, we focused on the Newfoundland and Labrador System Operator, the NLSO. And NLSO is a relatively new entity and we think it would be premature to say that it's not meeting the needs of stakeholders. But most of these responsibilities, in terms of what we said were the needs of current players, are ones that should be addressed in some way by NLSO.

And so what we would envision is that, as the system operator, NLSO is going to be seeking transparency, it's going to have opportunities for stakeholder interaction. Its activities will be subject to appropriate oversight by the PUB.

Now, this is an area in which the PUB has less familiarity because NLSO has only existed for, you know, approximately two years. But provided both NLSO and the PUB recognize that there's a learning curve and that resources need to be invested to ensure that it is not operating effectively, in theory, NLSO should be able to address most of the needs that we have identified.

So, we've then said, look, you know, we're not suggesting that changes need to be made right now, but we've gone through a series of questions that an entity like NLSO should be thinking about. So, clearly, near-term stakeholder engagement in development of rules is going to be important.

Longer term, NLSO and policy-makers will need to consider open access and how that squares with current – within province statutory monopolies, the question of whether there needs to be a separate independent market monitor that sits between NLSO and the regulator. That's something that we see in larger systems. It seems to me to be excessive over the near term in a system as small as this.

But there are issues as well, right? As we think about DERs – distributed energy resources – how do we ensure that NLSO can actually see the activities of the DERs to the extent that DERs are even allowed through anything other than a net metering system in the province?

Then zooming out regionally, in looking at the fact that we've got a number of system operators in the Atlantic provinces, each of which themselves is – may face perceptions that they are not independent, does it make sense to consolidate all of the Atlantic provinces system operators? How do we think about that going forward? Is it necessary to fully integrate them? Could you establish an energy imbalance market, as we've seen elsewhere? But these are issues that NLSO needs to be aware of and incorporating into its long-term plans.

So our consolidated response with regards to interconnection challenges, at the bottom of page 32, is that Newfoundland and Labrador's "system of regulation is evolving to meet the challenges arising from interconnection. Both the PUB and NLSO will need to further develop their capabilities … frequent stakeholder consultation" is critical. And open access needs to be properly implemented – needs to be sufficiently implemented to satisfy the reciprocity requirements of the United States. And then further thought needs to be given to what that means within the province. Risk management policies need to be reviewed at least annually, and both Nalcor and NLSO need to be mindful of US compliance challenges.

MR. LEARMONTH: Okay.

Now, we're on page 33, the role of environmental considerations in energy policy.

The question is: "***Should environmental considerations be made part of the Province's energy policy? If so, how?***" Please take us through that.

THE COMMISSIONER: Okay.

And we'll give you 10 minutes to think about that before you do.

So we are going to take our break now for 10 minutes first.

CLERK: All rise.

Recess

CLERK: All rise.

Please be seated.

THE COMMISSIONER: All right, Mr. Learmonth.

MR. LEARMONTH: Yes.

All right, Mr. Goulding, we're now on page 33 of the report and we're on the question: "*Should environmental considerations be made part of the Province's energy*" plan? "*If so, how*?"

Can you please take us through that topic?

MR. GOULDING: Yes, thank you.

So as we looked at this question, we thought, first of all, it would be useful to understand broadly what the energy policy and environmental policies were here in the province. And we understand that as governments change, the documents that exist may or may not represent the current state of thinking with regards to government policies. However, we started with our review of energy policy by looking at the 2007 comprehensive Energy Plan. We then also looked at the follow-up report from 2015. And both reports outline a series of energy goals, including demonstrating environmental leadership, as well as energy security, economic development, electricity export value, maximizing long-term value of oil and gas and ensuring an effective and efficient regulatory and governance structure.

So then we turned our attention to thinking about what the environmental policy might be, and we institutionally looked at policies of the Department of Municipal Affairs and Environment. And what we find is that, as in many provinces today, the bulk of the environmental policy can be found within various recent climate change initiatives. And so when we then look at what the high-level stated policy actions are that – excuse me – are associated with the Climate Change Action Plan, we see things like, on page 35, increasing energy efficiency in homes and buildings, implementing carbon pricing, increasing penetration of EVs, decreasing reliance on diesel for electricity generation, building climate change-resilient infrastructure and education and community outreach among others. So the action plan has various timelines, including reporting halfway through the five-year time frame.

Now, out of that plan, we thought it was important to highlight three sub-sectors that are critical when we think about the intersection of environmental policy and energy policy. So these included carbon pricing, electric vehicles and energy efficiency in homes and buildings. So carbon pricing obviously affects the relative benefit of burning fossil fuels relative to zero-emitting resources, whereas policies regarding electric vehicles and energy efficiency impact future demand for electricity.

So after reviewing energy policies and environmental policies in the province, we turned our attention to the question of how those policies were complementary and how they were in conflict. And, you know, the first thing that we observed was that the environmental plan already includes explicit references to environmental goals. So we see that environmental sustainability was, up front, one of the two guiding objectives. So, in fact, the plan built on initiatives outlined in the 2005 climate change action plan.

And, you know, as we looked at the energy policy and the environmental goals, we identified a number of areas in which there was significant overlap. So, you know, for example, we see energy efficiency mentioned in both the environmental and the energy policies. The carbon pricing in the environmental plan is consistent with the development objectives in the Energy Plan. So there are a number of areas where we already see some overlap.

So, we then turn to the question of whether and how these should be better integrated, and judging by the language of the plans, we can see that there was some effort made to have environmental and energy policies talk to one another. But we did not find evidence of formal, ongoing coordination, both in terms of the timing of future plans and in the ways in which the cross-cutting issues are addressed in terms of implementation.

So in terms of being able to say: Okay, the implementation plan for the Energy Plan and the implementation plan for the climate Action Plan have this nexus and we're going to have periodic meetings to determine whether we're meeting our milestones under an implementation plan. We haven't seen evidence of that kind of formality.

However, we would also anticipate that in a smaller province, that significant informal interactions occur between those responsible for the energy policy and those responsible for the environmental policy, but coordination is important. So, if, for example, there's a drive towards greater vehicle electrification, then that needs to feed into supply planning.

Furthermore, if you're anticipating electrification of transportation, then the regulator needs to start thinking about do – does our rate design reflect the specific issues that arise from EV charging and how would we apply things like time-of-use rates to encourage efficient EV charging?

We can also think about a similar action with regards to energy efficiency or electric heating. The long-term planning, the regulation and the pricing need to reflect expectations with regards to the use of electricity and future conservation initiatives.

So, if I turn to our consolidated response here in 4.5, we've said the following; we've said that: "Environmental considerations should be part of the Province's energy policy." Both energy and environmental policies are an exercise in constrained optimization. But as we think about what energy sources we're going to develop and how we're going to develop them, environmental policy is clearly one of the factors that has to be considered. So, the policies need to be clearly stated. Ideally, they should allow for multiple pathways for compliance and as the environmental policies are updated then the corresponding energy policy should be updated as well.

Specific areas of intersection should be explicitly referenced, there should be implementation plans and those implementation plans should be monitored quarterly by the appropriate entities.

MR. LEARMONTH: Okay. Thank you.

Now, we'll next go to page 40, the fourth [sp. fifth] question is: "At a high level, how effective is the current electricity pricing model, and should any changes to it considered? It is appropriate to continue to set rates for consumers of electricity on a cost of service basis or is there another more appropriate basis to set rates?

Please take us through that subject?

MR. GOULDING: Certainly.

So, to approach this particular question we started with a description of the current electricity pricing model in Newfoundland and Labrador, and at a very high level, this electricity pricing model is based on cost of service and cost of service has a long history in North America. It's a well-understood structure and it allows for reasonable incentives for appropriate investment and reliability subject to appropriate regulatory oversight. So, there are benefits of cost-of-service regimes.

After describing the current electricity pricing model in the province, we then turned to the question of, you know, what we mean by effectiveness. And the question that we were asked was the effectiveness of the electricity pricing model and the appropriateness of continuing to set rates using it. And so we've tried to define what we mean both by effectiveness and appropriateness.

So when we think about effectiveness, some of the criteria that we were exploring is whether rates recover prudent costs, whether rate increases are consistent with or below general levels of inflation in the economy on a longer term basis – recognizing short-term deviations exist for capital expenditures and fuel prices – that utilities and customers have a common understanding of desired performance and that rates are affordable given the level of performance desired and alternatives available.

So, we've then noted that there are challenges across all these measures of effectiveness. So, what we see is that rates in the future may be recovering not only prudent costs, but effectively covering cost overruns, which would normally be shared with equity. Rate increases are likely to exceed inflation. There may be differences in views as to the required level of reliability, depending on the views of customers versus utilities, and rates are becoming less affordable. So, the conclusion that you come to from that is that it's worthwhile to explore whether changes in the current electricity model are worthwhile.

So, what are some alternatives? Excuse me. So, when we think about moving from a cost-of-service regime, there's normally two aspects that come to mind. One is the extent to which you can move to market pricing for any part of the services provided throughout the value chain and the second is whether you should move beyond cost-of-service ratemaking and deploy performance-based rate making.

And so we've focused on the question of performance-based rate making here, and performance-based rate making can encompass a wide range of regulatory designs, but, generally, the objective is to provide incentives for efficiency and to allow for utilities and customers to share in benefits of productivity improvements. And so to get beyond the idea that the only way – aside from increasing customers – to increase revenues is to deploy more capital, to look at ways in which profitability can be improved by increasing productivity and, in turn, customers can then benefit by sharing in some of those gains.

So, we go through a range of PBR approaches that are on what we call the soft side, things like a lag or a rate freeze so that utilities can benefit for a period of time from productivity improvements.

Incentive targets, so clearly defining the performance that's expected, and then making sure that there are compensation mechanisms if those targets are met, but also financial consequences if the targets are not met.

Earning sharing mechanisms, which are fairly straightforward in theory – if the utility earns more, then its allowed return that's shared with customers, that may or may not be symmetrical so that in the case where utility – through forces beyond its control – earns less than its allowed return, it shares some of that downside risk with customers.

And then, finally moving towards the price or revenue caps that are involved in a full-scale I-minus-X regime in which rates are effectively capped at inflation minus some productivity target. And, so, the more intensive the mechanism, the greater the risk for both utility and the regulator, but, also, in theory, the greater potential for impact on bringing down long-term rates.

And, so, when we think about the comparison between the two – if I go back to page 42 at the bottom – when we look at Cost of Service, cost of service provides clear investment signals, it's a process that's well understood by stakeholders and has (inaudible) precedents. Performance based rate-making changed the focus from inputs to outputs, effectively. It's intended to incentivize efficient operations. In theory, it can reduce the regulatory burden, both for the company and for the ratepayers, depending upon how long the periods are between review and the extent to which annual reporting is changed.

So if I move then to page 44, in Figure 10, what we can see is that PBR has been adopted in some form by Alberta, British Columbia and Ontario. We can also see that explicit performance standards with or without consequences – or in some cases, performance standards are a matter of reporting; in other cases, they can be attached to specific rewards and penalties. Specific performance standards are more widespread.

So we've gone in to further details of PBR mechanisms in the appendix, I won't go through them here. It's worth mentioning that some of the pioneering jurisdictions for PBR have now moved into what we call next-generation sets of arrangements. And so, the challenge with PBR has always been to try and figure out how to get the appropriate balance between incentives for capital expenditure and operating expenditure, how we get utilities to make the right decisions.

And so the UK is moving towards what they call a totex, or a total expenditure regime, that's intended to eliminate those challenges.

We also see exploration of a so called regulatory sandbox that allows for stakeholders to come in and pioneer certain kinds of trial rates or trial arrangements.

So, we then see that another form of next-generation regulation is the idea of further evolving the role of the distributer in thinking about the distribution entity fully unbundled from transmission and generation, serving as a platform on which new technologies, distributed energy resources can interact with one another. And so, the idea is that the distributor gets paid for distribution services and customers can either continue with their traditional supply from competitive wholesale market coming through transmission, or they could interact with other distribution-cited resources that provide attributes that are of value to the customer. So, we're beginning to see some exploration of these models, particularly in New York.

So, I'll touch briefly on – you'll recall that when I started this section, I noted that PBR and wholesale competition were two things that can be considered as we move beyond cost of service, and we've seen some discussion of a form of unbundling here in Newfoundland. While unbundling and use of markets is something that we support as a theoretical concept, I think that we're concerned that use of export referent pricing today would have serious challenges that would need to be addressed, and so we don't consider that as being something for the present.

So, then we were asked to assess appropriateness. So we put forth eight potential principles to assess "the appropriateness of a particular regulatory framework." These include: transparency, administrative simplicity, incentives compatibility, consistency with cap ex cycle, provides the opportunity for a fair return on prudent investment, reflects technological evolution, provides value to ratepayers, and reflects local conditions.

So, we took those criteria and then we assess them against the four models, and so we've got the high-level summary in Figure 11 of how each of the potential models compares to the various criteria and we noted that the various models, you know – because they're assessed on a high level we gave them a basic definition. These models could incorporate a wide range of various attributes.

It's important to acknowledge that the current system of electricity pricing in Newfoundland has some incentive characteristics. There are some earnings sharing mechanisms, some rate applications are not performed annually and the fact that there are some embedded incentive characteristics could help facilitate transition.

So when we look at next generation PBR and distribution use of system arrangements, we don't think that those are consistent with current conditions in Newfoundland and Labrador, and so we've excluded them from consideration. We've already noted that there's some challenges with the current cost-of-service structure here in Newfoundland and Labrador, and so we've landed on exploration of performance-based rate making as being a recommendation.

But we have to caveat that by noting that it's not something that can be implemented overnight, and that while it has the potential to mitigate some potential rate increases, it is an incremental change. The orders of magnitude will be small and shifting to PBR doesn't make pre-existing costs disappear. So improving incentives for productivity, changing approaches to capital expenditure planning and linking performance standards to consequences are important, but we need to be realistic about the outcomes.

So in conclusion, with regards to current electricity pricing model effectiveness, we do believe that the current electricity-pricing model is not as effective as it could be, and that the province should consider evolving to a PBR framework.

MR. LEARMONTH: Okay. And that's because it's the more appropriate basis to set rates than COS, right?

MR. GOULDING: Yes, that's correct.

MR. LEARMONTH: Okay.

Thank you.

Page 49, the question is: "***Is there likely to be any role for renewable energy generation expansion in the coming decades, either for internal use or for export?***" Could you take us through that, please?

MR. GOULDING: Yes.

So in order to answer this question we had to start with a definition of renewable. We reflected the Energy Plan Progress Report of 2015, which included hydro, solar, wind, tidal, geothermal, with the potential for biomass to be considered as well. So if we're thinking about whether there's a role for renewable energy generation expansion, we need to define it; we need to then make sure that the technical possibility exist. Is the resource there? Next we need to determine whether the demand is there and we have to determine whether the transmission, if there is demand, is available to meet that demand if we're considering exports.

So we also need to be clear over what time horizon we're considering. We chose 20 years in this particular case, because that was consistent with the planning horizons that we see in various system operators.

So as we look at the technical potential, in theory, leaving aside economics, there is significant potential particularly for hydro and wind, solar is less effective in Newfoundland than elsewhere in North America, and geothermal, theoretically possible but it takes a while to understand the resource. It's costly to develop, but there is some theoretical potential.

MR. LEARMONTH: Just to stop you for a minute on that before I forget.

There's been considerable interest in this province on the subject of wind power.

MR. GOULDING: Yes. Yes.

MR. LEARMONTH: And, you know, many think that the wind resource has been underutilized and that it would've – if utilized to a greater extent it would've taken away a lot of the reasons for Muskrat Falls.

Can you give us some information about the state of technology with respect to wind power? A high-level thing – is it something that is evolving? Are there technological improvements? If there are improvements, are they being developed on an accelerated basis or is it flat? Just touch on that subject, please.

MR. GOULDING: Certainly.

So one of the challenges with many of the renewable resources that have been identified is that they are intermittent, and so let me divide the technological changes between ways to address intermittency, which are really with regards to storage of some type –

MR. LEARMONTH: That's batteries, is it?

MR. GOULDING: That's – that is primarily batteries, but wind could be integrated with other types of storage, like compressed air or storage hydro, to help to firm the product. Now – but battery costs are falling, batteries are still, you know, expensive.

And so what we also see, however, are developments that increase the productivity of wind, whether that is with regards to larger unit sizes, bigger blades, moving production offshore to take advantage of better wind regimes, some improvements in controls that allow for ride-through capabilities so that you can avoid situations where you're offline for a long period of time because of voltage fluctuation. As well as better forecasting capabilities, your ability to forecast in very short-term increments helps you to better integrate wind into a larger system, because you may be able to better utilize the resources that are balancing the wind as the wind comes off. So these are all areas of technological development that are ongoing.

MR. LEARMONTH: Okay. Do you expect that these developments will continue?

MR. GOULDING: Yes.

MR. LEARMONTH: Yeah. And is there research being undertaken in the United States, to your knowledge, to advance the storage of battery – battery storage and things like that?

MR. GOULDING: Yes, there's a great deal of research across the national labs, across academic institutions and within commercial entities to improve battery storage and there's a large interaction between the developments that are happening with electric vehicles and batteries in electric vehicles, and those that would be used for electricity storage more generally.

MR. LEARMONTH: Are you optimistic on that front, that as time goes by, that we will be able to use more wind power incorporated into our systems?

MR. GOULDING: I am optimistic that developments in battery technology will enable better integration of intermittent resources like wind. I think the question arises whether that means that large centralized resources, large wind farms, coupled with large-scale batteries will be the dominant technology, or whether the developments of smaller scale batteries will encourage distributed energy resources to the point where these DERs will become a more common solution and reduce the need for centralized resources.

MR. LEARMONTH: All right.

All right I interrupted you**,** you can pick up where – at the point of the interruption, please.

MR. GOULDING: Certainly. So, the broad level summary first of whether, if money demand and transmission were not an issue, is there significant renewables potential in Newfoundland, and the answer yes. And so what we see is that, you know, if we look at figures – even those taken from the ministry in Figure 13 at the bottom of page 52.

We see in terms of terawatt hours that the view is that there's significant initial potential for hydro – I think that's something that is commonly understood – wind both onshore and offshore; and that future potential is larger than the existing provincial supply requirement. So, we then turn to the question of whether it's needed, right. So, we are confident that it exists, but how is the load going to evolve.

So in order to answer that question, we first look at the need for new generation within the province. And when we look at the reliability and resource adequacy studies that have been done, the base case through 2028 suggests that there's no need for incremental capacity additions under the base case.

Now, in this particular study, there were 23 other cases that looked at how supply and demand balances could develop. And the – even if we accept only those that had new resource requirements, the range within the next decade was between 58 and 175 megawatts. So even under the most extreme criteria, the need is relatively small.

When we extend the outlook to 2038, we then see that there remains relatively small potential for need, such that there's certainly the potential that there would be no need and certainly that, in general, it may even be challenging to reach the 58 to 175 megawatts identified in the extreme cases from the planning exercise previously mentioned.

So as we think about renewable development for internal supply needs, we do also need to be cognizant of the intermittency factor, because the resources would need to be balanced. When we look out at the costs of the various resources, to the extent that further renewables development did occur in the province, the relative economics in figure 15 on the top of page 56, suggests that that development would be wind or a combination of wind and storage, with the wind and storage being comparable to the lower end of some of the small-scale hydro, but the wind and storage being superior in its dispatchability.

There is a role for renewable energy as well in remote communities or behind the meter. But that role is small. It is focused on either continuing to have fuel oil as a backup, and trying to reduce the use of fuel oil with small-scale renewables or, ultimately, renewables plus storage.

So when we then turn our attention to, okay, we've determined that, generally speaking, over the next 20 years we think that there's going to be minimal need for additional renewable development, then we said, okay, well let's look at the export markets. And when we think about the export markets, first we have to say, is there going to be demand, is load growing in those states or provinces? And, secondly, do we have the capability to get it there? Is the transmission there?

And in looking at the transmission linkages, there is not significant spare transmission from – excuse me – Newfoundland to neighbouring provinces or the US that's not already called upon by existing resources. And then when we turn our attention to the question at the top of page 58 of whether load is growing in the export markets, what we see is that load growth projected by the individual, independent system operators in the case of New York and New England, or using utility plans in the case of neighbouring provinces, we see really minimal to negative load growth.

And so that means that the potential in the export markets is not driven by load growth. And it's also not driven by potential retirements either. So when we look at alternative sources of supply in those export markets, we see significant efforts at the state level to develop a variety of resources that are within the boundaries of the state or region.

The – so – and there are a number of circumstances that need to be considered, right? First of all, the price received by exports from Newfoundland would need to justify not only the cost of the resource, but also the cost of the transmission into that export region. So in looking at the pricing of what it would take to develop various resources here in the province and then export them, relative to some of the contracts that have been signed in those jurisdictions, it's difficult to make the economics work.

And when we also take into account the procurements that are being sponsored by those states for things like offshore wind within state waters, what we see is very little role for newly developed resources in Canada to serve load in US jurisdictions. So existing planned transmission is linked to new, existing plans for generation in Canada. But in terms of incremental new generation in Canada and incremental currently unplanned transmission, that would be an extremely challenging economic prospect. So in terms of whether resources from Newfoundland can compete in export markets, we are skeptical.

So, consolidated response: There's limited role for renewable energy generation expansion in Newfoundland and Labrador in the coming decades. Such expansion is more likely to be justified for internal use, but given that load growth in Newfoundland and Labrador is expected to be minimal with few existing – few additional retirements of existing generation stations, we're expecting that renewables expansion will be small in scale and episodic.

Initial opportunities are more likely in remote communities to reduce use of fossil resources. Wind or wind plus storage installations are likely to be most cost-effective and importantly can be installed in smaller unit sizes and more rapidly than new hydro. Export markets are unlikely to provide justification for renewables development in Newfoundland and Labrador given slowing demand; cost of transmission; and the existence of closer, cheaper resources.

MR. LEARMONTH: Okay, thank you.

I know it's not part of the scope of your work, but I do want to ask you a few questions about the situation we're dealing with in 2041 when the contracts between CF(L)Co and Hydro-

Québec come to an end. As you said, I know you're not – you didn't study this for your report, so if the questions are things that you don't feel comfortable asking, please just say so. But are you aware that in 2041, the contracts with Hydro-Québec that were signed with CF(L)Co come to an end and that at that time, there's going to have to be some renegotiation or some way of dealing with the approximately 5,400 megawatts of power at the Churchill Falls station? Are you aware of that?

MR. GOULDING: Yes, I am.

MR. LEARMONTH: Yeah.

Now, from a – once again, a very high level, what options do you believe exist for this province to maximize the value of the Churchill Falls Generating Station when the contracts expire in 2041?

MR. GOULDING: So I want to caveat this by saying that this is a very high-level answer.

MR. LEARMONTH: Right.

MR. GOULDING: I have not done extensive research with regards to transmission availability, contractual structure or other matters associated with the arrangements in 2041. But the options are really twofold. One would be to obtain further rights, additional rights that would continue beyond 2041, to wheel the power through Quebec. The other would be to consider whether it is feasible and appropriate to build alternative transmission facilities through some other route that would provide access to export markets. Those are really, at a very, very high level, the two alternatives that would be available.

MR. LEARMONTH: Okay.

And when you say wheel power through Quebec, isn't there – there are two parts to that. One option could be to continue on with the existing system where the province sells to Hydro-Québec and then Hydro-Québec makes its own commercial arrangements. And the second part – the alternative to that would be to obtain the right to – for the Province of Newfoundland and Labrador to transmit or wheel power through Quebec. They are slightly different, aren't they?

MR. GOULDING: Yes, that's correct.

MR. LEARMONTH: Yeah.

How realistic, based on your experience in the energy field, is it for Newfoundland and Labrador to expect that we will be able to get wheeling rights through Quebec? Do you feel comfortable commenting on that?

MR. GOULDING: I don't feel comfortable commenting on that.

MR. LEARMONTH: Okay, that's fine.

And so there's two – I think Mr. Pelino Colaiacovo, managing director, Morrison Park, testified and he said that – the gist of his evidence was that really, there's only two options: negotiate with Hydro-Québec or build a new subsea transmission line to the United States. Do you agree with that – with those two – that those two options are the only realistic ones that are probably available to the province?

MR. GOULDING: Yes, I believe that's a fair statement.

MR. LEARMONTH: Okay, thank you.

One other topic I want to cover with you – your – do you deal with long-term forecasts in your work?

MR. GOULDING: Yes.

MR. LEARMONTH: Do you do long-term forecasts yourself?

MR. GOULDING: Yes.

MR. LEARMONTH: Yeah.

And for utilities, can you give us some information on the range that you consider to be reasonable to make long – to make forecasts – how far out do you go? And can you tell us the pitfalls, if any, of going out too far? What happens when you go out beyond a comfortable range?

MR. GOULDING: All right.

So the forecast horizon – you know, we're generally asked to look at between 10 and 20 years. So the further out you go with regards to a forecast, the greater uncertainty that exists. When you're doing short-term forecasting, there's a variety of forward market estimates, for example, in terms of fuel-price inputs. There's diverse estimates of load growth. We understand the existing technologies. We understand the system as it exists, right? But once you get beyond a 20-year forecast horizon, the uncertainty with regards to the assets that exist, the technologies that are there, the ability to load forecast increases substantially. And so in terms of the wait that one would put on the longer term portions of a forecast, you would need to have a much wider band of potential outcomes to ensure that you – that in your estimates, you encompass what was actually going to happen, right?

So when you think about your high and your low case, for example, and you want to try and make sure that, let's say, 95 per cent of potential outcomes occur within your high and your low case, your ability to have some confidence that that's the case, you know, it starts to decline after 10 years. It declines more after 20 years. And once you're getting beyond 25 or 30 years, the best you can do is make a good faith effort with what you know at the time. But you don't know whether solar panels are going to cost, you know, 50 cents per kilowatt or $5 per kilowatt or $1,000 per kilowatt; leaving aside the question of whether those are in real or nominal terms.

So that's just an example of some of the uncertainty that would go into it. You know, even now when we look at things like hydrology patterns, right, and whether hydrology is changing, that degree of uncertainty is increasing the further out that we go.

MR. LEARMONTH: And it's year by year? Thirty-two years is more risky than 30 or 28?

MR. GOULDING: Well, I wouldn't want to put it in that degree of granularity. I would probably go in, sort of, five-year increments or five- to 10-year increments. You know, is a 32 more risky than a 31? I think they all, kind of, fall into the –

MR. LEARMONTH: All right.

MR. GOULDING: – same class.

MR. LEARMONTH: But it is a progressive thing within (inaudible) –?

MR. GOULDING: That's right.

MR. LEARMONTH: (Inaudible), yeah.

Now, I'd like you to have a look at – there was a comment made in the Nova Scotia UARB on the dangers in long-term forecasts. And I'd like to bring this up, it's Exhibit P-00245. It will appear on your screen, Mr. Goulding, not – it's not in your book. And it's page – P-00245. It's Exhibit P, zero – excuse me, and it's on page 30 of that exhibit. This is the decision of the Nova Scotia Utility and Review Board on the Maritime Link application. It's the July 2013 decision. And in that – the Nova Scotia UARB retained Morrison Park advisors, that's Mr. Colaiacovo (inaudible).

I'd just like to read out a passage from the decision where Morrison Park is quoted on the terms of long-term forecasting. It will just take a minute but I'd just like to get your comment to see whether it accords with your understanding and beliefs on this subject. It says, quote:

"A very significant component of the work of this Review involved the use of forecasts, projections and estimates, and in particular those provided by the Applicant in evidence and in response to information requests. … It is critical to point out, however, the fundamental uncertainty that underlies many of the projections in question, particularly as they extend out not only years, but decades. Useful forecasts for the near to medium term are typically based on the belief – sometimes proven by subsequent events to be erroneous – that the future will consist of incremental changes to the practices of the past. However, the longer the time horizon of the forecast, the more likely that changes will cease to be incremental, and hence become truly unpredictable. What may appear to be reasonable today may at some point in the future – with the benefit of hindsight – look like a terrible mistake, or a massive stroke of luck. Prices change, technology changes, market dynamics change, the relative cost of goods changes: all in unpredictable ways over time.

"Technological advances, in particular, can render assumptions obsolete even in relatively short periods of time. …

"There is a significant danger in assuming that a view of the future from the perspective of today will be very accurate. All such assumptions should be approached with humility, and treated with respect as the best available basis for decision-making, but without claiming them to be more than what they are. Decisions cannot be made without taking a view of the future, but the future may prove unwilling to agree with the forecasts made of it.

"It is commonplace that commercial transactions are analyzed using mathematical models, often providing a degree of precision measured in decimal points, which sometimes gives the illusion of accuracy or predictive power. We have used such models in this Review. However, these models are only as accurate as the assumptions about the future that underlie them. Since those assumptions must be given a broad range because of the difficulty inherent in predicting the future, especially over decades, the models should and do result in outputs with an equally broad range. This means that mathematical models sometimes may be capable of excluding certain decision options from the realm of reasonable commercial choice, but cannot always point to a single preferred outcome among several. In these case, decisions still must be made, but they must be rendered on the basis of judgement.

"Commercial decisions are ultimately about judgement, and judgement is extremely difficult to quantify."

Now, that's a fairly long extract but you've read it before, I understand.

MR. GOULDING: Yes.

MR. LEARMONTH: What is your comment on the – on this passage? Do you agree with it? Do you disagree with it? What's your take on it?

MR. GOULDING: So I agree with it, but I would want it to be read as a plea for doing thorough work rather than as an excuse that a forecast in the past didn't turn out to be as expected. And so, you know, I particularly like the observation that, you know, we need to treat assumptions with humility, that we need to make sure that we don't overpromise with regards to the accuracy of the forecasts.

So I think that these are critical points to keep in mind, but I also think that we can distinguish between a thorough job that's done with regards to a forecasting exercise and one that is biased. And so I don't think, in and of itself, the acknowledgement that the future sometimes turns out differently than forecasted, should excuse, necessarily, a forecast that didn't turn out to be correct.

MR. LEARMONTH: Okay. Thank you.

Just for the record, I'd also like to refer to a similarly persuasive statement on the dangers of long-term forecasts, which is a December 2011 article in *The Evening Telegram* [sp. *The Telegram*] by Maurice Adams, an energy specialist and commentator on energy matters. It's on the public record but I think it's certainly consistent with the passage I just read on which you commented.

MR. GOULDING: Yeah.

MR. LEARMONTH: Those are my questions.

THE COMMISSIONER: All right, thank you very much.

So it's almost five to 5, so we'll break here now and we'll begin cross-examination – sorry.

MR. SIMMONS: Commissioner, Mr. Young is with me today and was going to be doing the – a short examination of this witness, and he's not available tomorrow.

So if – we could break now and I'll pick it up tomorrow or if we have a few minutes Mr. Young might be –

THE COMMISSIONER: No, it's – how long do you expect to be Mr. Young?

MR. YOUNG: I can be as quick as need be, but I didn't expect anymore than 10 or 15, at the most.

THE COMMISSIONER: Okay. Well, you're prepared for this, correct?

MR. YOUNG: Oh, indeed, oh, yes, but I just have a couple of areas to explore.

THE COMMISSIONER: Right.

Okay –

MR. YOUNG: But we're in your hands.

THE COMMISSIONER: You know, I don't know what the view of others is at this stage, but it would mean Mr. Young is not coming – able to come back tomorrow and puts more onus Mr. Simmons, I guess, in that situation. I'd like to try to accommodate him.

Is there anybody with any strong objection to that, including you, Sir?

MR. GOULDING: No, I don't object.

UNIDENTIFIED MALE SPEAKER: I don't.

THE COMMISSIONER: All right, well, let's do it, and just as you're walking up I'm gonna make another comment, Mr. Young.

So, it strikes me now, and it struck me when I reviewed the – you just come on up – it struck me when I was reviewing the report earlier this week, when I saw it, that, you know, this was a late endeavour by the Commission to obtain the services of London Economics and, as a result, it is a high-level review.

So, one of the thoughts that I had, and I say this particularly to the government and as well to Nalcor, is that it would be helpful to me if it was possible to have some sort of a response to the report in the sense – and I'm thinking about areas like with regards to the energy regulation for sales outside of the province, the FERC, the NERC and all that sort of stuff. And, you know, even for the government, for instance, with regards to the suggestion about trying to ensure that the – that we keep monitoring what is happening out there to make sure that we are following the rules, you know, with regards to open access and whatever.

So, whether there is an actual ministerial committee or whatever that's looking – overlooking this sort of thing or environmental changes, whatever was discussed, I wouldn't mind being updated on that and to see if there is something there. And it would be something I would make as an exhibit, obviously, so that in making any recommendations, because the real point of having this witness testify was to look at our regulation system to see whether or not there's any improvements that could be recommended, it would be very helpful to me in making that choice.

So, having said that, I leave it with the parties, and it doesn't mean that other parties including the Consumer Advocate, for instance, would not be able to respond either if they so wished.

All right. Good. So, Mr. Young, proceed.

MR. YOUNG: Thank you, Commissioner. We'll take that point –

THE COMMISSIONER: Okay.

MR. YOUNG: – under advisement. We understand your point, and I will say that I had, I thought, a little bit more cross-examination but in the presentation Mr. Goulding gave today it allows me to speed this up quite a bit.

And what I'd like to do, if I might, is follow a little bit on the how to – sorry, the – it's the how to do things. You've been very useful in your report and in your testimony this afternoon with respect to what you think might be useful for us to do from a regulatory, from an environmental way to proceed.

Just wanted to point out one matter with you. You talked in your report with respect to – I don't think I need to bring you to it – with respect to ensuring that the ratepayers shouldn't be taken advantage of in an energy marketing situation with respect – what I'll call the free-rider –

MR. GOULDING: Yes.

MR. YOUNG: – opportunity. That would, I would suggest to you, apply to a transmission circumstance and if there was a circumstance where energy marketing was leaning on the reservoir of Hydro, it would apply to that as well, you know, for an opportunity to buy low, sell high. Correct?

MR. GOULDING: Yes.

MR. YOUNG: So I don't know if you're aware, but there has been an application to the board and a matter has been decided upon, a ponding agreement. So, our board is involved in that application. They have approved, on a provisional basis, a pilot agreement with respect to that.

Did you have any knowledge of that?

MR. GOULDING: So I have not reviewed that in detail. So, I was aware generally that there was a proceeding going on –

MR. YOUNG: Okay.

MR. GOULDING: – but I've not reviewed that in detail.

MR. YOUNG: And I'm not suggesting that you should've. I'm just raising that as an example of the sort of thing that I think you're indicating the regulator should be involved in.

MR. GOULDING: Yes. That's correct.

MR. YOUNG: So, if I was to inform you that the regulator provisionally accepted that and that any upside would be put in a deferral account for potential sharing and that the energy market took all of the downside risk –

MR. GOULDING: Mmm.

MR. YOUNG: – that would be consistent with the way you think these things should be treated, would it or would that surprise you?

MR. GOULDING: I think, broadly, the idea that the ratepayers share in the benefits and the entity that is actually going out there making the decision bears the consequences of loss, strikes me as being an appropriate balance. So, without speaking to the specifics of the agreement, I would say that such an arrangement would be appropriate.

THE COMMISSIONER: So let me just try to – 'cause you lost me, so I need to catch up to you.

MR. YOUNG: Sure.

THE COMMISSIONER: So are we talking about some sort of a contract for the sale of power – of export power – that you've taken to the PUB – that Nalcor's taken to the PUB to get approval of? Is that what we're talking about?

MR. YOUNG: Yes, it's in fact a short-form agreement whereby Nalcor's entitled to go to the market, purchase energy when it's very low, essentially store that energy in the reservoirs, and Energy Marketing can then have an opportunity to sell it at a higher price. So that's reliant, to some extent, on the infrastructure of Hydro –

THE COMMISSIONER: Okay.

MR. YOUNG: – to do that.

THE COMMISSIONER: I understand now what you're talking about. Okay.

MR. YOUNG: Yeah.

So – and it strikes me that it's analogous to the circumstances of the use of the transmission lines. I thought I would just raise that with you.

To a slightly different topic. There was a discussion about the regulator ought to have a role in approving sales. I just wanted to clarify that was for – for Energy Marketing, I mean – that was for longer-term arrangements, not short-term or spot sales or anything of that nature. So this would be long-term, perhaps, firm contracts. Is that your (inaudible)?

MR. GOULDING: So, I was articulating a concept without talking about the duration –

MR. YOUNG: Mm-hmm.

MR. GOULDING: – in the sense that the regulator should have the ability to approve or deny contracts that adversely affect the consumers in some way.

Now, I think that my intent wasn't to suggest that the regulator should have oversight on the day-to-day trading operations on short-term operations, except were there to be, you know, a case where there's some kind of clear violation, right. For some reason, the result of those short-term trades – and this is kind of linked to the ponding discussions – but if you could imagine a short-term trade in which Energy Marketing is selling at some price, external, and keeping the benefits, but that activity causes greater operation of a higher cost resource here in the province, then you would anticipate that that's something that the regulator would want to be aware of. But generally speaking, when I spoke of approvals, I was envisioning longer term contracts that would at least need to get a no-objection certificate that there are no issues that affect ratepayers.

MR. YOUNG: Understood, thank you.

Moving on to some of the PBR discussion.

MR. GOULDING: Yes.

MR. YOUNG: I'll – I won't drag everybody through that, but perhaps I can pose it this way: Most jurisdictions in Canada are cost-of-service, fairly traditional approaches with sprinklings of PBR concepts or the use of some opportunities to use PBR methodologies where appropriate. Would you agree with that statement?

MR. GOULDING: I would – I guess my issue is with the sprinkling in the sense that, you know, when I look at the kind of percentages and at least the interest –

MR. YOUNG: Mm-hmm.

MR. GOULDING: – in it, I would say it's more than a sprinkling.

MR. YOUNG: Yes.

MR. GOULDING: It's not – you know, if we look at the charts, it's clearly not a majority. Now, if you did a – kind of a load weighting or a customer weighting, then you would come to a different conclusion. But if we go province by province, right, what we would say is that the larger the province, the more exploration there's been of performance based rate-making, whereas, at the smaller end, I think there's been continued interest in what we might call looking at performance standards –

MR. YOUNG: Mm-hmm.

MR. GOULDING: – and incentives around those performance standards, which, in and of itself, is a form of kind of small-scale, targeted PBR.

MR. YOUNG: Right. Yes, I would agree with that. So your recommendation, as I understand it, is an encouragement, for this province, to move gradually towards that where it works. Is that correct?

MR. GOULDING: Yes.

MR. YOUNG: Thank you.

Just one other – I suppose this has got to do with regulatory structure, another topic of that sort. You – in your paper, you give a good comparative survey of the way that certain regulators have the opportunity to approve capital, certain don't. What's happened here, of course – and I think you can confirm this – is that it's quite granular when it comes to – perhaps you would suggest it's far too granular with respect to approving capital. However, when you came to Muskrat Falls and that matter –

MR. GOULDING: (Inaudible.)

MR. YOUNG: – it was made exempt.

MR. GOULDING: Yes.

MR. YOUNG: Right. Is that a common approach for megaprojects in other provinces, historically?

MR. GOULDING: So I think the challenge is that when a provincial government wants to do something, it will find a way to do it. And so I used the example of Kemper in the report, right? Well, that was a private utility that took the initiative, that went out and did it and ultimately lost its own money as a result. It wasn't the State of Mississippi that was saying, we're going to go out and we're going to make this thing happen.

So what we've seen among Canadian provinces is that if you want to do Site C, you're going to do it. If you want to do Keeyask, you're going to do it. I don't believe that's good regulatory practice. I believe that anything that goes in the rate base and that's going to be reflected in rates needs to go through a full regulatory process.

So, to me, the fact that it's common, you know, even in Ontario where we have directives, right, that have caused things to be built without regulatory review, I believe it's the wrong approach. But it's also very hard under a parliamentary system to stop. And so, yes, it's common. I wish it weren't as common as it is, but it doesn't mean that all these projects are bad. It just means that the process that they've gone through has been attenuated and would have benefited from further review.

MR. YOUNG: If I can take up where you left off there, with respect to directing the board, and that's what happens in these cases –

MR. GOULDING: Yes.

MR. YOUNG: – they're either exempted or directed or –

MR. GOULDING: Yeah.

MR. YOUNG: – as we see here in other places, a combination of the two.

MR. GOULDING: Yeah.

MR. YOUNG: There's a fair bit of discussion in your paper about environmental policy –

MR. GOULDING: Yes.

MR. YOUNG: – and it working together –

MR. GOULDING: Yes.

MR. YOUNG: – with energy policy.

MR. GOULDING: Yeah.

MR. YOUNG: Just on the mechanics of that, is it typical that that would be done by way of a specific direction or a general grant of authority to the regulator to consider environmental matters in the public interest?

MR. GOULDING: So I would say the latter. Now, I want to emphasize: I'm giving a high level – it's not that I've gone through and done a province-by-province, you know, analysis of every single directive that's been done.

But, generally speaking, the best practice is you tell the regulator, look, here are the high-level constraints under which you're operating, these include, you know, environmental, they include property rights, they include certain other things. You go ahead and do your job based on these constraining factors.

So if we've said, for example, no nuclear, then obviously you're not going to consider nuclear, but similar to that, if you have an environmental law or an environmental policy, then directing them at a high level to take that into account is – meets the criteria of, you know, clarity, transparency, providing an appropriate mandate – all of these things that are good practice.

MR. YOUNG: Thank you.

Commissioner, I appreciate the indulgence of yourself and the witness and those present. Those are all my questions.

THE COMMISSIONER: Oh, no problem. Thank you, Mr. Young.

All right, we'll adjourn for the day and we'll come back tomorrow morning at 9:30.

CLERK: All rise.

This Commission of Inquiry is concluded for the day.