NEWFOUNDLAND AND LABRADOR
BOARD OF COMMISSIONERS OF PUBLIC UTILITIES
120 Torbay Road, P.O. Box 21040, St. John's, Newfoundland and Labrador, Canada, A1A 5B2

Hearing Transcript

REFERENCE TO THE BOARD
RATE MITIGATION OPTIONS AND IMPACTS
MUSKRAT FALLS PROJECT

October 17, 2019

PRESENT:

The Board:

Board Members
Darlene Whalen, Chair
Dwanda Newman, Vice-Chair
John O'Brien, Commissioner

Board Counsel / Staff
Maureen Greene, Q.C., Reference Counsel
Sara Kean, Assistant Board Secretary

Parties:

Nalcor Energy /
Newfoundland and Labrador Hydro
David Eaton, Q.C., Counsel – Nalcor
Geoff Young, Q.C., Counsel – NL Hydro

Newfoundland Power
Kelly Hopkins, Counsel
Liam O'Brien, Counsel

Consumer Advocate
Dennis Browne, Q.C. – Consumer Advocate
Stephen Fitzgerald, Counsel – Consumer Advocate

Island Industrial Customer Group
Paul Coxworthy, Counsel
Denis Fleming, Counsel
Dean Porter, Counsel

Witnesses:

Island Industrial Customer Group
InterGroup Consultants Ltd., Patrick Bowman

(9:00 a.m.)
CHAIR:
Q. Good morning, everybody. Welcome back, Mr. Bowman. Mr. Coxworthy, I'll turn it over to you to introduce your presenter.
MR. COXWORTHY:
Q. Thank you, Madam Chair. As you've just recognized, Mr. Patrick Bowman is being called this morning as our witness for the Island Industrial Customer Group. Although he's appeared before this Board before, I note he's with InterGroup Consultants, and I will ask him to give just a brief summary of his experience in the area of regulation of public utilities.
MR. BOWMAN:
A. Good morning, Chair, and members of the panel. I am a principal with InterGroup Consultants. I have been working in this field for 21 years, and in the province here since the 2001 rate bearing. I've prepared evidence in this jurisdiction six times. I work in about ten different jurisdictions in Canada, provinces, and territories, and some work in the US and international. Focus has

been on Crown owned and hydraulic utilities primarily working for utilities, at times industrial customers, small consumers, sometimes for regulators and also for governments in respect of energy policy. Specific to the issues at hand today in regard to mitigation and rate shocks that arise from large new developments, I've been involved in a number of cases including the Mayo B Hydro Project and the Mayo-Dawson Transmission Line Projects in Yukon, each of which similarly involve bringing on large capital projects. In Manitoba, recent proceedings related to bringing on the Keeyask Hydro Electric Project and the Bipole III Transmission Line. In Northwest Territories, the Blue Fish Dam Replacement Project, which similarly drove significant rate impacts, as well as helping the NWT Government develop a hydro strategy which would deal with how to avoid rate impacts when large new projects come on, and as part of that, I was involved in investigating a number of historical projects across Canada and how they were brought into cost base and

rates for utilities without causing rate shock, and I'm currently involved in a proceeding in Alberta that is partially driven by major HVDC transmission build out, and rate impacts arising from that.
MR. COXWORTHY:
Q. Thank you, Mr. Bowman. I understand that there are some corrections to the version of your presentation that was circulated last Friday that you would draw our attention to?
MR. BOWMAN:
A. Yes, that's correct. The corrections are entirely on what is noted as Slide 20, and they relate to the Synapse Revision One that was produced. A few of the numbers in our presentation were not updated to the Revision One numbers, and so they are updated on the slides that will be used on the screen this morning, but in the version that was distributed, they were not yet corrected. One is under a bullet that says, "The net adverse impact of the CDM to Revenue is 41 million". The version that was distributed had a different number there. The other is in the paragraph below

the bullets where there's a reference to CDM that should read "34 million", it now does. It previously read 40 million. One word was changed where it had said "underline", the correct word is "undermine" in the second line. Those are the only changes that were made.
MR. COXWORTHY:
Q. Thank you, Mr. Bowman. Mr. Bowman, perhaps you could take us through your presentation.
MR. BOWMAN:
A. Yes, thank you. In regard to this proceeding, the submission that was prepared for September 20th and the recommendations prepared were prepared by me or under my direction. I was retained by the Island Industrial Customer Group which represents approximately 10 percent of the firm load on the island, approximately 43 million in total allocated cost, and the concerns that the IIC Group has consistently had relayed to us as we've been involved for coming up on 20 years with this group, is the fact that they have large capital investments in the province, they're effectively captive

and rely on Hydro for their supplies. They must have a long term perspective, given their captive nature and the fact that their investments have a long term focus, and they're exposed to continued power purchases from Hydro. This leads to concerns related to long term stability and predictability of rates and fair allocation of costs. This issue will come up when we discuss CDM later in this presentation. Flexible power options which will come up somewhat in discussions about industrial customer opportunities specifically for things such as capacity costs, economic development, and the fact of the matter is that rates are quite critical to this group, not just bills, and that is, in part, due to their current loads which they must pay the rates, but also considering future opportunities or related to other future industrial customers that are not yet here. Rates are what people will notice. We thought it important to relay the estimates that we have about the impacts that will occur to this group without mitigation. The rate impacts that

have been estimated are, I would say, extreme. The average rate coming out of the last General Rate Application was around 5.22 cents for this group. The rate for any given customer will be slightly different because of their mix of capacity of energy, for example, or for their specifically assigned charges. The last estimate we have was that that rate could rise to 12.44 cents after the projects are fully in service, which is an increase of almost 140 percent. This occurs on top of rate increases that they've seen, approximately 30 percent since 2013, or 50 percent over the last decade. There's going to be some discussion in this presentation about CDM options that could further drive rate impacts up to 0.5 cents, which may seem small in the 12.44 that we're discussing here, but that's an extra 10 percent compared to the bills that people are already paying. To help underline the point of the impacts, we distributed a document that just recently came out from Hydro-Quebec which does a comparison of bills across the country, and I don't know

if we can bring that up on the screen. There we are. This document, the page that's highlighted here is page 22 of the document, and it is a summary of average rates paid across Canada and for selected American cities for different sizes of customers. The customers that I'm discussing would be in the final column listed as "Large Power", particularly the final column. To give you an idea, that is approximately the size of the middle consuming customer, the group that I'm dealing with. It's within the range of that, and if you look down the column, you'll see the range of types of prices paid by industrial customers across Canada. St. John's is listed there at 5.61, which is a little bit different than the number I quoted, but that's due to the mix of demand and energy assumed and the timing. This was an April 1st rate, but you'll see that compared to the 5 cent rate, absent mitigation we're talking somewhere in the order of 12 cents, and one just has to look up and down the column there to see the jump

that would occur in the relative prices compared to other jurisdictions, even across Canada, much less when one adds in the American cities, which are all in Canadian dollars, by the way. I've provided a slide here, Slide 4, which copies in the summary of the areas I intend to address from the evidence. As I'll be speaking to each of these, I don't intend to dwell on it on this slide, but there were five areas that it seemed merited comment out of the Liberty and Synapse Reports. One of the first things that we spent some time on was the question of what is mitigation, what is meant by the scope of task that could be captured by mitigation. We focused on the task which was options to reduce the impact of the project on electricity rates, which was specifically cited in the Reference Letter, highlight electricity rates for the importance that rates matter, particularly with regard to the opportunity to do further electrification and grow loads. The document that's pasted in there is an excerpt from a government document produced in April, 2019, which was a preliminary plan for how to deal with mitigation. I was pointed to this document as context by the clients that I deal with. It's referencing mitigation related to the year 2021, as one will notice there, and the understanding is that it was meant to provide a road map about how the mitigation plan might unfold, which was produced prior to, of course, this Board doing its work. The highlights that were brought to my attention were the fact that the Newfoundland and Labrador investment, government investment, was highlighted at 249.1 million in effectively foregone provincial benefits compared to what would have been assumed. These are not necessarily from subsidies, these are from lowering the cost of profits that are built into the project, and the other item that is highlighted here is down the table at row 8, which is add value to energy surplus at 35.5 million, and if one goes into the detail of that row, it is about effectively attracting new industrial customers and new industrial loads, and that seemed an important part of

the mix and my understanding is it continues to provide a significant opportunity if one is able to achieve it. The clients highlighted to me that they weren't sure how this fit with what was happening today, whether there's already the commitment that rates won't go up and this is about detailing that, or whether this is an aspirational target and the current proceeding is about figuring out whether we can do it. I, obviously, don't have a view on that, but I will use aspects of this as the road map as we go through the following slide. Moving on to the first topic area that was important to discuss, and which is one of the biggest items in the mitigation plan, is foregoing government benefits and returns. This slide provides somewhat of a description of the context that we were relying on in preparing the submission, highlighting that governments benefit may ways from developing major projects, some of them tied to dividends and returns, but not all. There's also significant things such as taxes earned from workers completing the

projects. Many of those will have already occurred and will already be in place by the time this project has been dealt with on rates. Liberty's assessment was that there is substantial and growing amount of potential for support from foregoing government benefits and returns otherwise built into the financial model. To highlight Liberty's conclusions, I reproduced the graph from their evidence report, and this does not lead to any radical recommendation, but that Liberty's work seems to be thorough and sensible and that those dividends and water rentals and other items, excess energy, highlighted in this graph should be pursued as part of targeting rate mitigation. The other thing I'll note, though, is the previous page that had the initial plan put out by government had highlighted the potential for 249.1 million coming from the Newfoundland and Labrador contribution to mitigation in 2021. Liberty is still well short of that, so I think although these are large amounts, they're not sensational and there would

still be a question to be raised if opportunity existed to where does 249.1 come from and why does this number still fall quite short of that. A separate topic raised by Liberty relates to the regulated company itself, Hydro, and the question of dividends and an equity target. Currently Hydro is operating with a 25 percent equity target and is securing a return on equity to build equity in the company with no dividends expected until it reaches the 25 percent equity target. This chart shows the dividends that would be payable over time with a different target. In this case, a 20 percent target, and it shows the dividends that could be made available to mitigation start to come in much larger and much sooner at a 20 percent target, at the expense of later years, which is noted by Liberty. The 20 percent target was not advocated by Liberty. It was not included in the previous graph, but it was something that was highlighted as having a significant potential.

(9:15 a.m.)

It's important to note that Liberty highlighted this as a timing difference, but timing is effectively what matters in the question of mitigation. It's relatively clear that the Muskrat Falls and the overall project costs will be paid over time. The mitigation impact is what happens in the early years and how one deals with the timing of when the costs arise. So to the extent that timing may be understood as something that's dismissive of this opportunity, I don't think it should be viewed as dismissive. It's a significant opportunity, it's a significant amount of money, it's over 100 million dollars in mitigation potential and it should be pursued. To underline that point, I'm also dealing with a similar project coming on line in Manitoba, the Keeyask Generating Station, which quite closely followed on a major transmission development. In Manitoba, there was a major hearing before the project went into service in approximately 2013, and there were financial plans produced and which have continued to

be produced over annual financial plans prepared by Manitoba Hydro, long term plans which has Manitoba Hydro's equity ratio currently scheduled to drop to about 12 percent and at times it was in those plans dropping to 9 percent as the project is absorbed into the rates. Now the situation is a little bit different in the case of Manitoba Hydro. There the asset is a part of the rate base, so some of the return equity ratio effect is a denominator effect, it's adding a very large asset base. So while the numerator, the amount of equity is growing slowly, or in some cases even going down, a lot of that erosion occurs because you're adding a very large amount to the denominator, but it's worth highlighting that Manitoba Hydro's plan has routinely shown years of small net losses during the period where "digesting the whale" as it's sometimes been called during the time that this project is being brought on line, and people are trying to find a way not to shock rate payers. While that leads to a little bit of erosion in the equity level and net

losses on the books, which may or may not occur, but it has been part of the plan. It's a key part of being able to manage the rate impacts at a stable level, somewhere in the order of 3.5 to 4 percent a year, and it's able to be incorporated into an overall long term plan because they can show how the numbers turn around over time. Now I express concerns about what I understand to be Liberty's caution regarding lower equity ratios and the potential to impact credit ratings. I raise this topic mostly because the area of credit rating and credit worthiness is a very specialized area of practice and I would encourage, before conclusions are made there, that people have all of the input that's needed from people who practice in this area. I've been involved in some of it, but it is not core to my expertise, but I would emphasize that the evidence that has been provided in Manitoba specifically and others, is that equity is not normally the first concern when one is dealing with credit ratings or credit worthiness. Equity is a number on a

balance sheet. It does not represent the cash flows that are able to repay the lender. Credit ratings are about whether a lender can read whether they're going to be repaid. Equity can't pay your bills. Cash flows are needed to pay your bills. The Manitoba PUB came to the same conclusions, and I actually provided quotes from that in the submission I've prepared on page 16. The second thing is that because the credit rating agencies are focused on this issue of cash flows to be able to pay the bills, the revenue base of the utility is critical, and one will see that if you read through the credit rating reports that are provided in IR-PUB-Nalcor 213, particularly Attachment 11, which is DBRS. You'll see that the first thing cited by the credit rating agencies is the problems from pressure on rates because failing to deal with the pressure on rates will undermine the sales and the loads, which is the source of cash that the utility can use to repay the debt. So if you're looking at the situation and saying am I better off with more equity or am I better off with more mitigation, the first thing they would highlight is sales, prices, and maintaining your loads, that mitigation is more important than equity. The other thing that I highlight is that self-supporting status is sometimes held out as a sort of a gold standard or the area one does not want to broach, and that is fair at a general level, but once we're into this type of terrain, that needs to be understood at a more detailed level. Self-supporting status is not necessarily the impact that is assumed. It's not necessarily intuitive. Specifically, a number of utilities have had their self-supporting status removed by Standard & Poor's due to methodology change. It didn't necessarily lead to downgrades to any of the provincial governments. I'm talking about Manitoba, for example, and SaskPower, and New Brunswick. That was due to a methodology change by Standard & Poor's, but these utilities, at least Manitoba Hydro has already confirmed it will probably never achieve self-supporting status under Standard & Poor's ever again

because of the way Standard and Poor's measures it, and the fact that Manitoba Hydro is not structured in that manner. Standard and Poor's is measuring it as if it's a stand-alone company, and Manitoba Hydro operates closer to what we sometimes call "a glorified co-op". It's not going to build equity on the backs of customers just to have equity or just to have – just to pay down debt that is otherwise a cost effective way of financing assets. I have more comments on this in the paper. I don't know that I intend to dwell on it much longer, but I did want to highlight that when one digs into the credit rating agencies, there is a methodology that is used by these rating agencies. The methodology has a number of assessments in it. Among the assessments are for determining whether an entity – what its rating is and whether it's self-supporting, among the assessments is the strength and scope of the regulator. So if someone is concerned about self-supporting status, among the things that can be done is to maintain the strength and

scope of the regulator, and I raise that in regard to comments that have been made about what aspects of the power system here are regulated versus non-regulated. In general, these rating agencies will look to a strong regulator with a broad scope as supportive of self-supporting status. So broader scope for the regulator can help secure that objective of self-supporting status. The last thing I was going to comment on this is it's generally understood in financial markets that the key indicator of credit quality is the prices you're able to get for your debt. It's not necessarily your credit rating. Credit rating is often a lagging indicator. So if someone was concerned about this topic and wanted to monitor, the thing to monitor is the prices that Hydro is able to get for debt that it issues, or the prices that the province is able to get, and whether those are showing erosion, much more than whether the credit rating agencies have yet responded. As a result of that summary, I would say that absent direct and compelling evidence of difficulties

accessing credit markets, the equity target should be revised to 20 percent or lower as part of a long term plan that shows how Hydro can meet its bills, can continue to sustain a positive cash flow and an equity ratio over time. It can be a long time. Manitoba Hydro, as I said, is producing ten year and twenty year financial plans for showing how it can reach equity targets, and the benefit in the form of either lower dividends or a lowered ROE target, which is actually preferable, should be part of rate mitigation to customers, given that that's a material amount, 111 million. I also have a recommendation there that in support of the evidence of self-sufficiency, regulatory independence expansion should be supported. I don't intend to get into the details of the corporate structure of the entities where LCP resides and energy marketing and the like, but the broad scope of the regulator is one thing that can be done to show support for the fact that an overall sensible financial scheme will be established and maintained and to provide support for those credit rating agencies.

The second topic that was – received comment in the submission is in regard to increased cost efficiency. On this slide, I highlight that there was an assessment of asset transfers. Liberty concluded asset transfers between Hydro and NP would be complex and that NP has higher carrying costs for capital investments, and as a result, any asset transfers must yield operational or efficiency benefits to outweigh a cost of capital disadvantage.

I agree with their assessment and I agree that there does not appear to be material benefits available from asset transfers and I wouldn't think it would be prioritized as a mitigation action.

Liberty highlights that normal capital spending, if we can call it that, outside of the major developments needs careful review. They highlight half a billion dollars in planned spending over five years by Hydro and NP. I agree and I would understand that that type of review would be planned to occur and I would highlight that it should

occur in a particularly cautious way at this time, given the rate impacts that would otherwise be occurring.

One specific item not raised by Liberty and I raise here because it hasn't been mentioned and it may not be -- ultimately be a concern, but there wasn't an opportunity to explore Liberty's conclusions or reply to them through RFIs, is that to the extent that capital plan includes projects that have a resource planning aspect, meaning projects that bring online added energy or that change the output of existing plants. We should be careful to ensure that that other added energy is valued at the marginal value of that energy.

We're currently in an environmental or going to be in an environment where there's significant surplus energy and that surplus is not particularly valuable, due to the prices that are able to be secured from the export markets, and my understanding of Hydro's approach to assessing its capital projects is it would look to that value if it's considering something like a re-

rendering project or something that would increase the output of a plant or life extension or those types of things. And Hydro would have that outlook because its costs would be affected by the marginal value of that energy. The exports, the swings in the exports that would occur.

Newfoundland Power, however, would be facing a rate structure that is a bit insulated from that marginal cost because they buy their power from Hydro at a different price, at a wholesale rate, which absent mitigation would be going significantly up and the potential would occur for Newfoundland Power to assess its resource planning projects at the price of wholesale power, would avoid buying from Hydro, and that would not be the appropriate economic outcome and so, I'd encourage there to be a structure put in place that Newfoundland Power's resource planning decisions are also assessed based on the overall Island marginal costs, the value of that power at export.

So, for example, if Newfoundland Power,

one of its hydro plants has the opportunity for life extension versus mothballing or for re-rendering or something that would bring online more energy, the value of that energy shouldn't be considered at the wholesale rate. It should be considered at what it does to the overall Island. In other words, what it does to the ability to secure exports overall. And if that lower price leads to a different decision on capital developments that decision should be driven by the overall Island marginal value.

I've now moved on to slide 13. Liberty provides an assessment of LCP operating costs, as well as other items in regard to cost efficiency. There are some conclusions in Liberty about the phase-in period to reach steady state operating costs and other efficiencies that can be achieved. I don't attempt to summarize it all on this slide, but in general, I would encourage the Board to take note of those recommended cost efficiency initiatives and ensure that Hydro reports on those in the next GRA and the progress that has been made.

Moving to slide 14, I have comments in the report about the specific topic of depreciation. It's concerning to see that depreciation is not a bigger opportunity at this time because it's normally a key aspect of considering major new projects and how to manage the rate impacts of them. Effectively, it's how quickly do you pay down the assets links to your potential for principal payments on debt as well how you recognize the cost of an asset and the value of the asset in rates.

(9:30 a.m.)

It's not uncommon to find ways to structure either debt or depreciation to help cushion, help manage the impacts of large new projects coming online and effectively, in this case, as I understand it, those options are foreclosed by the financing structure that's put in place.

I accept – on this slide, I note that Liberty raises two reasons why depreciation does not receive greater attention. One is because it's a non-cash effect. Effectively, if one lowers the depreciation,

you don't generate any more cash. You just lower accounting costs. And if you've already found a way to tap all of the cash flow towards mitigation efforts, you don't necessarily further benefit mitigation by simply changing numbers on a sheet of paper. That's true, and I accept that.

And the second reason they raise it is because the structure of the agreements that were – go beyond Liberty's scope effectively are tied to debt repayment and an asset service life that would otherwise need to be renegotiated and Liberty's scope did not include the details of how one might renegotiate those things. And I accept that conclusion as well.

And as a result, I don't think there is a – is easy to provide a clear recommendation on depreciation alternatives, but I would encourage parties who are considering renegotiation to include the potential for a different means of recognizing the cost of the assets, of depreciating them and paying them down during this early period when the rate

impacts are this significant.

I do provide some examples in the submission about different ways that has been done. I don't know the extent to which those could be on the table, but I would understand those discussions to be occurring outside this room, but I wouldn't think – I wouldn't think it would be out of place to encourage those discussions to consider the pace of paying down the assets as part of the options that may be considered for mitigation.

Moving on to Synapse. Synapse's report was focused on topics related to loads and customer use and maximizing exports. There was a primary question posed to Synapse, as I understand it, definitely posed by Synapse in the report that they were meant to answer, which is it more advantageous to maximize domestic load or to maximize exports. I think that on balance, reading Synapse's report, the conclusion is quite clear that it's almost always more advantageous to maximize domestic loads.

Sales in the Province that can be for

beneficial uses, whether that's expansion of industries, whether that is displacement of oil, whether that is new uses that customers would come up with, almost always aid in the efforts we're here to discuss, which is how to deal with rates, according to the reference.

There are very few exceptions, which is if that added load only rises because you heavily discount the rates or if that added load only arises at the worst of the peak times because there is pressures on cost at times of the highest domestic peaks.

I also raise a concern that when one goes through the Synapse report, it appears to be misaligned with the reference scope which was about rates. I think Synapse excessively focuses on bills, and I'll spend a minute or two why I think that's a problem. I'll say that's not always a problem, but what Synapse has done is not outside the industry norm, but 140 percent rate increases are not the industry norm and so I think we're in a different situation here and that's why one might come up with a bit of a need for a different focus than I think Synapse has taken in certain areas.

One thing that Synapse did not address in any detail was – which is a high priority item for Industrials – is recognition of the rate disruption and usage pattern of Industrials, competitiveness factors and the importance of power rates to competitiveness, not just on external competition, meaning the value of the product produced by Industrials, but also internal competition, which can relate to whether an Industrial plant within a larger company is able to compete for capital to keep its plant up to date and operating.

We'll often hear this from Industrials we deal with across the country. They're part of global – national or global enterprises and they're constantly dealing with internal competition in their companies and they are constantly fighting for limited supply of capital dollars to renew the plant to keep up to date, and failing to be able to justify the capital dollars means that the plants that are here effectively are –

will overtime become obsolete; will overtime not have the reinvestment needed for them to continue a long life and it's a type of pressure on their future existence.

I put it's understandable why Synapse didn't deal with this in a larger way because it is a very challenging topic and a very large topic. Synapse used some discussion of elasticities and how customers might rely – sorry, how customers might respond to rate changes. And they do note that Industrials have some of the highest elasticities, but those elasticity studies don't deal with rate impacts at the scale we're talking about here. And so I think that Synapse was in a challenging spot in regard to that.

One example of an area where I believe a rate mitigation focus is merited and was highlighted in the Government plan, and I cited early on, was how to go about electrification, expanding the load, investing in new Industrial customers or in regards to possible added uses by existing Industrial customers and the problem and the

opportunity that arises from the fact that absent mitigation you'd be dealing with higher rates, 12 cents. Even with mitigation, you might be dealing with five to six cents. Whereas not using that power domestically means it can be sold to export markets that may yield you 3.3 cents or 3 and a half cents.

And the question is, if we're shipping this power outside the Province at 3 and a half cents or 3.3 cents, are there uses for it here in regards to building the Industrial base here that we're not capturing because we're trying to charge the customers here more like five or six or possibly 12 cents. Are we really in a place where we say buy it for 12 or we'll sell it for three, but you can't have it for three?

And that's a problem because it's inconsistent with what's laid out in the Government plan. It's a problem because it means you're not doing the best for competitiveness and development in the Province and it's a – it misses a potential significant opportunity.

I can see discussion of that in the Synapse document. To the extent that Synapse dealt with the topic, they appear to be suggesting that one would not want to yield from the full price unless a customer was coming to you with a bona fide threat of closure. They lead it in a section on load retention rates. It's the only one that talks about Industrial rate options and I thought that was a bit narrow and disappointing, and I wouldn't want to see that dropped, the opportunity to discuss further what could be done with electrification and with expansion of Industrial loads and so, I've encouraged that that topic stay alive in some form, whether that's Government conducting a review of Industrial competitiveness and load retention and bringing in energy intensive loads.

But I don't think that there's been enough information here for us to know how that could occur, how to capture the 35 and a half million dollars in added load benefits that the Government plan, original plan was relying on. And I wouldn't think that that is a topic that it's time to stop talking about.

In regards to electrification, from what I could see Synapse did a relatively thorough job. I would note their plan is based on scenarios, not precise program designs, but they do provide numerical representations of the effects of different programs.

The information that I'll provide in this slide is updated compared to Section 6.1 and 6.2 that is in the submission that was prepared September 20th, based on Synapse's revised original one to their information, but the numbers don't change significantly. So, the conclusions still hold about electrification.

There was a document distributed which was just the excerpt from Synapse's revised report that I thought it was worth going through the table, just to highlight their – this is best – it's coming up on the screen now. But highlight where these numbers are coming from and why electrification is shown

to be so beneficial.

This is from the – the document on the screen now is from Revision 1 of Synapse's report and it's from the executive summary. It's one of the more interesting tables, from my perspective. It focuses on a subset of scenarios that Synapse thought it important to highlight and electrification is particularly highlighted there at Case 10, the high electrification scenario.

And as you move across this table, it's all in millions of dollars and it is showing two different time points, 2025 and 2030. I'll focus on 2025, but if you want to look at the 2030, you'll see that the impacts are actually even more significant. And I'll say that the conclusion out of this table is that high electrification is highly beneficial.

For 2025, it's important – added electrification is bringing 54 million dollars in incremental revenues to Hydro, sorry, it's 51 million in the corrected version. And we get that by saying that Hydro would sell 65 million dollars in added

power with 13 million in lost export revenues. So that its sales overall has gone up on the order of 50 million dollars.

In order to achieve that 50 million dollars in added sales for the same quantity of power, overall same quantity of power generated, Hydro will have to incur 20 million in costs. Three million to run the programs and 17 million to deal with the fact that that added load drives a higher need for capacity. So, by the time we're done on this table, the revenue requirement, the amount required to be recovered from rate payers is benefited 33 million dollars. We require 33 million less from all the existing rate payers.

That 33 million, if we go to the page before this, page seven of the Synapse, Revision 1, that 33 million you'll see highlighted again. This is Table 1 of the Synapse executive summary. Again, high electrification is row ten. You'll see that same 33 million benefit. That 33 million benefit allows you to have rates that are half a cent, .49, half a cent lower than

they would have been.

In other words, the customers who electrified had the opportunity to displace oil, see positive bill effects, which Synapse has the rest of this table highlighting. But even if you have no role in electrification, if you're a customer who's just using power the way you've always used it, you will still see rate benefits from the fact that other customers electrified and bought more power and bought at a higher price than the export market would have provided.

So, this is what would be considered a type of win-win situation. Electrification benefits the participating customers. It also benefits the customers who don't participate. And as a result, electrification is, as set out by Synapse, subject to program design, is highly beneficial and it should be pursued.

There's another scenario that we don't have to switch back to, but which takes the same electrification and it adds some time-of-use and demand response aspects to help avoid that peak. If you remember when we went through that electrification scenario, we were getting added revenue from the sales, but those sales were also driving a higher peak, which led to 17 million dollars in capacity costs.

An add-on to electrification is finding a way to avoid that 17 million in capacity costs and Synapse effectively concludes you can avoid ten million of that added capacity costs by spending four million on demand response type programs and time-of-use rates, particularly where you're using electric vehicles. As a result that .49 cent rate benefit becomes a .6 cent rate benefit, which is, you know, a significant improvement for spending four million to save ten.

As a result, the demand response option should also be pursued and I would highly – with that, the importance of the Industrial curtailment and capacity assistance programs being shown to be highly economic.

(9:45 a.m.)

When Synapse comes on to CDM, we end up

with a much more challenging economic profile, and I'm going to walk through this, but I effectively do this twice to show two different ways of looking at the numbers that are here, but to emphasize what some of the statements that have been made mean.

So, first looking at CDM the same way as we just looked at high electrification, if we can go back to Table 2 from Synapse's Revision 1 of their executive summary.

Pursuing high CDM means spending on programs or incentives to get customers to use less power. As a result of that, sales will decrease and this shows that Hydro's sales or the consolidated sales go down by 55 million dollars in 2025 from high CDM.

Now, that power that's freed up is able to be exported, and as you move across the table, you'll see that that exported power could yield 14 million in export revenues. So, you've got a net impact of loss revenue of 41 million dollars.

In order to achieve that CDM, this shows that you would need to spend nine million, and that's an amortized cost, but

nine million. But that because loads are down, there's a peak capacity saving of 16 million. By the time you put those together, you end up with a net adverse impact to the utility revenue requirement from CDM that is shown there as 35 million. I quote it as 34, simple arithmetic, but it's, you know, 30 some odd million in change in utility revenues that represents costs that Hydro will incur that are no longer being recovered from the same sales when it's made at the same rate.

And as a result, if we go back to Table 1, top row, page six, high CDM, you see that 35 million negative number change in utility revenues. That has to be addressed by a .549 rate increase on all the other sales made on the system.

So, if somebody is not participating in the program or if they've already done their efficiency or if they're living in a situation where they can't do CDM or particularly from the clients that I deal with, if somebody's looking at a new expansion or a new customer is looking at

coming here, those higher rates are what they're going to face. They're not going to see the bill savings that are being pursued by the participants. They're just going to face those higher rates.

So this, at the outset, before we deal with the specific program design, is effectively a win-lose type of program. Participants can be winners. Non-participants or people who can't participate, afford to participate or who aren't here yet and will be eventually developing can end up as losers in this mix.

Now, given the mitigation mandate is about lower rates and given we're dealing with an environment where we're dealing with extreme rate impacts and that's the focus, CDM should be looked at cautiously.

There is a test for CDM that was not applied by Synapse in coming up with their design, which is looking only at those that can have a positive rate impact. In other words, within that mix of programs, you can run CDM which has a positive rate impact which doesn't lead to rate increases to other customers. And there's a test for that and it's known as the rate impact measure as an indication of win-win CDM.

It is not always applied and I know that that evidence has been given, reading the transcript. There are other types of tests that have been recommended or applied by Synapse which are described as more industry standard. I don't disagree there are other types of tests. I will say that the rate impact measure is an industry standard. It's not always used as a primary one, but we're not always in a situation where customers are facing 140 percent rate impacts.

The types of tests that others were discussing, for example, the program administrator costs test, which I believe was referenced by NP's panel, are a normal test for DSM as well, but they have a different focus.

The Program Administrators' Cost Test will effectively look at the world through a lense of resource acquisition. It says, if I need to get more kilowatt hours compared

to what it costs me to go get them from new developments, is CDM a cost-effective way of getting those extra kilowatt hours? It won't look at revenue at all. It doesn't even consider lost revenue from customers. It just says if I need a million kilowatt hours, I can go build something that supplies a million kilowatt hours or I can go pay customers to get my million kilowatt hours which is more cost effective. The reason that test doesn't necessarily apply today is because we're in a surplus. We're not going looking for those kilowatt hours. We're not—we don't have a supply-focused situation. We have a rate-impact focused situation and that type of test will not be considered. We'll not be looking at whether rates go down as a result of this because it basically assumes that the rates are going to have to cover this million kilowatt hours I need, but we're not in that situation. We don't need the million kilowatt hours. At its basic level, that's why the Program Administrators' Cost is not necessarily

well-suited to the current situation. It's also being applied a little bit in a modified fashion here because it's really supposed to look at the utility's costs, but we've defined "cost" to include changes in export revenue. It's not supposed to look at revenues. So, we've put in half the revenue picture because we put in the export revenue as the value of our cost of foregone, but we don't consider the domestic revenue. So, even at a basic level, the PAC, the C being cost, we've already sort of modified in looking to applying it in this situation. The key is that RIM Test can be a total solution for distributive effects. With a RIM, there's no need to solve showing distributive effects which I'm going to—it will be the last slide I deal with. And they're focused on rates, just like this inquiry is. Now, I said I would take one through looking at the picture again as to why these distributive effects are such a big deal. This is the same CDM case where I've just—I've rearranged the numbers and

I'll say that when one looks at CDM Tests, there are effectively three groups of tests that you can look at. There are consolidated tests. The consolidated tests look at what is the overall impact on the jurisdiction, ignoring customers' money and utility money. I'm just going to put all of this together and say what are the consolidated impacts on the jurisdiction? They can include social factors. They include other things. Total resource cost here, TRC tests for example is one that people talk about. Benefits--some benefit cost tests are that way. A second set of tests are participant tests and they say, is the participant better off by being part of this program? And you have to pass the participant test or else people won't participate at all. So, those types of tests are going to be looked at as to whether a program will work, but we're going to focus on the third set of tests which is the utility test. It's how does this work out for the utility and ultimately for its cost to supply its loads? In this slide, you know, I will sort of walk through those tests and using the same set of numbers for the high CDM case. Remember that we said that from outside the jurisdiction, by running high CDM, we will get extra export revenues of 14-million dollars. We also said we would save 16 million in capacity savings. Both of those are bona fide benefits to the province. Actual dollars coming in from exports and actual avoided need to spend on capacity. So, there's 30-million dollars if we're only looking at the entire consolidated picture, there's 30-million dollars of benefits. We can achieve that 30-million dollars as the second bullet shows by spending 9 to run the program. Synapse uses this and talks about a three-to-one-benefit ratio. That's the types of numbers they're talking about. We spend 9; we save 30. We're all better off, right? As a whole, we're better off, and when you can pass a consolidated test like that, people would say, "Yes, that's a good

program and all we need to deal with now is who gets the benefits of us being better off." Distributive effects or program design or technological fixes, but here's why that's so challenging. In this case, that 21 million in net provincial benefits ends up arising as a 55-million-dollar-bill savings to the customers who participated in the CDM. So, the bill-savings that are being provided is two and a half times the benefit that they're actions caused. There's a 34-million-dollar gap and that's the question of where does that come from. And the answer is, right now, it comes from a half-a-cent rate increase to everybody else. So, when you hear the term "All we need is to deal with distributive effects or a technological fix," what people are basically saying is, "All we need to do is make sure that we don't get that 34 million from everybody else, that we get from the customers who saved." So that everyone else isn't harmed, we have to get it back from the customers who saved otherwise. That's

the only place where it can come from. So, how do you get the 34-million dollars back from the customers who participated? You have to find a way to effectively claw back from them 60 percent of what they thought they were going to save because they think in running the program and saving energy, they're going to save the 20-cent rate, but there's only somewhere in the order of 8 cents of real benefits from them cutting back their loads, between that and the export and the capacity. And that's what the distributive challenge is and waving one's hand at it and saying that's just a program design element, I think undermines the extent to which that is a serious problem that has to be carefully looked at. Otherwise, you end up with these impacts of, like I said, half a percent rate, the impact on the rest of the rate payers which, as I noted, that's almost ten percent of what industrial customers are paying, their bills now. So, the conclusion there is pursue CDM where you can have a positive RIM Test,

where you can have a positive effect on rates. That should be done anyway. Be cautious when you don't because the program design elements can mean that you end up in—with small benefits, in this case 21-million dollars, and a very difficult time making sure that that doesn't end up costing non-participants or some of the other sub-groups that people talk about, whether that low-income people who can't participate in CDM, new industrial customers who weren't here yet. So, they're only looking at the fact that rates are higher and they're not going to be as competitive, those types of things. I will say we were not able to get all of the numbers to work exactly out of Synapse's report. So, when I quote eight cents, it's developed just for some ratios. We didn't have the opportunity to ask some RFIs, but I didn't see anything in there that suggested a problem. It's just that we don't have the—some of the detail. I believe that addresses everything in the presentation this morning.

MR. COXWORTHY:
Q. Thank you, Mr. Bowman. That concludes the presentation for the Island Industrial Customer Group.
CHAIR:
Q. Thank you.
MR. COXWORTHY:
Q. Thank you, Madam Chair.
CHAIR:
Q. Thank you, Mr. Coxworthy. Thank you, Mr. Bowman. Hydro and Nalcor, do you have any questions?
YOUNG, Q.C.:
Q. Thank you, Madam Chair. Good morning, Mr. Bowman. Welcome back to sunny St. John's. A bit of reprieve from snowy Winnipeg, I guess. We live in dread here for our first winter storm. I'm just going to discuss two areas and I think my question has been cut short because your last topic you discussed in some detail. So, it's not going to me terribly long on that one, but my first area I'd like to discuss with you is—it starts on page 14. I don't think I need to turn you

to it. I'm going to read you a sentence from your report and then ask you to respond to a question with regard to it. And it's got to do with Hydro's equity targets and making adjustments, that sort. And your sentence is, "It's not clear that Liberty retained a specific credit rating or capital market expert to generate this conclusion which would be appropriate and necessary to make a defensible assessment in these areas." I think when you discussed your background, you don't consider yourself specifically a credit rating expert? Is that correct?
MR. BOWMAN:
A. Correct.
YOUNG, Q.C.:
Q. You're a bit more of a generalist than that?
MR. BOWMAN:
A. Correct.
YOUNG, Q.C.:
Q. So, you know, we've seen such experts testify in this room before and they typically do an analysis of—to get a sense

of the cost of equity. They look at the spreads between long Canada Bonds and discount of cash-flows and huge tables of comparable companies and utilities, but the commentary you've provided seems to come mostly from a single point in time and a recent Manitoba Hydro regulatory ruling. Is that basically correct as to the source of your discussion here?
MR. BOWMAN:
A. Well, yes. Can I comment on why? Is that –
YOUNG, Q.C.:
Q. Yes, sure, please.
MR. BOWMAN:
A. The main reason is because it's very recent because a lot of things that we're dealing with here are very similar to what Manitoba Hydro is facing in terms of a major new project coming online and because there's been a lot of development in the capital markets situation in the last few years that are very relevant to this. For example, Standard and Poor's changing its target for what it considers self-sufficiency, and as a

result, three or four utilities, Crown utilities across Canada, are being considered not self-sufficient.
(10:00 a.m.)
And beyond all that, mostly it's always been taken as a bit of sacrosanct that utilities need to be self-sufficient, and Crown utilities, to avoid putting any impact on the government and it's kind of the no-man's land over there that we just don't want to approach. These days, a number of utilities are approaching it. And so, there's been a lot more focus, particularly in Manitoba, about what does this really mean when we approach it? What does it mean that Standards and Poor's no longer consider that as self-supporting? Because there was always—that's the one thing you don't want to happen and now it's happened. So, what happened? How did that arise? Can we avoid it? So, there's been a lot more detailed focus at that level in the last few years, particularly, I'd say Manitoba is the best recent example, but about this, about this

question compared to, I think, the history across many of the jurisdictions or past years.
YOUNG, Q.C.:
Q. The other credit rating agencies, like we see a lot of Moody's and DBRS. Have they reached the same conclusions about those utilities not being self-sustaining?
MR. BOWMAN:
A. No.
YOUNG, Q.C.:
Q. Okay. So, it's really a change in, I guess, methodology of Standard and Poor's that bring us to this point?
MR. BOWMAN:
A. So, Standard and Poor's had a change in methodology which is critical and allowed us to test this theory about whether self— losing self-supporting status really was as bad as everyone said it would be. DBRS and Moody's are also though commenting on things like the erosion of (unintelligible) capital ratio. You see it in their reports. The language isn't that different than the

reports that you have filed here which says that we're facing challenging times. They do focus on things like 10 and 20-year financial plans that Manitoba Hydro can provide and it shows that even though it might drop to somewhere between 9 and 12 percent equity and have planned net losses, even at average waterflows for a period of time. It shows that those things will turn around. So, they do focus on the long term and it hasn't led to downgrades, but of course, it has the normal line that says if conditions eroded or if facts change, we might downgrade.
YOUNG, Q.C.:
Q. And just further to that point, I noted when I had a look at the Manitoba report, and they seem to be looking at the appropriate equity thickness giving a sustained five-year drought potential. So, I guess my question is, when a rating agency or a regulator looks at a utility for this, it can't easily use information from other jurisdictions where that is based on very

specific tests and considerations?
MR. BOWMAN:
A. Right. And in particular, in Manitoba Hydro's case, Manitoba Hydro effectively self-insures drought by way of its equity. If it has a bad drought, it's going to lose money. Manitoba Hydro lost 400-million dollars in the drought in 2003. The whole system is designed for that though. That's why it effectively has equity, and so, their stress tests are all about what does a drought cause? Here, we have different things like an RSP that manages water.
YOUNG, Q.C.:
Q. Yes, but the need to access the capital markets is still present?
MR. BOWMAN:
A. Absolutely.
YOUNG, Q.C.:
Q. Yes. And you made a comment which I think if we agree, I think everybody agrees with, that the timing does matter for rate mitigation. You were talking about the period of time during which potentially a

change in the equity thickness could be endured and the CEO has spoken to that and the vice-president of Finance for Hydro, Ms. Hutchens, has spoken to that, with caveats. A certain amount of that can happen for a period of time before they get too concerned. After that, they do get concerned. Is that the kind of information that they also set in Manitoba and other places in your experience?
MR. BOWMAN:
A. Yes, and not to be too flippant about it, but these are also kinds of topics that are not just dealt with numerically, but also in a sense--I'm trying to find the right word. Like lyrically or culturally that when one— sometimes the numbers can turn against you and people will say, "Well, we still have certain confidence," but when a certain confidence is lost, even if the numbers start to go for you, the confidence doesn't come back quickly. And credit rating agencies take into account a certain qualitative aspect as well, as do lenders, a

certain qualitative aspect assessment of risk. And so, those things, not only can go against you on the numbers, but once they go against you on the numbers, they can have a certain hangover effect.

YOUNG, Q.C.:
Q. And further onto credit rating agencies, you said something which I had not heard before and I'm curious as to whether it's a widely-held view and that is that credit rating agencies are a lag indicator which is to say they look at a utility's or a company's difficulty in attaining low-cost debt and then they respond to it. And that seems to me to be, from the way most people see it, an upside-down thing. Most people would look at the credit rating agencies and then assign a debt cost arising from it, but you see it differently?

MR. BOWMAN:
A. Well, I encourage you to read the record from the specific Manitoba Hydro hearing as well, but I don't—I think at the time, it was an example of the non-intuitive

information that is coming out. When people are assessing being closer to this margin, that effectively, the people who are doing the lending aren't just sitting there reading a credit rating agency report and taking that as sacrosanct for what—where they're going to put their billions of dollars, right? These are sophisticated lenders. They're going to do their own assessment. They're probably going to be more sensitive than a credit rating agency. They're certainly going to be more up to date than a credit rating agency. In the case of Manitoba Hydro, there's points where they were borrowing ten-million dollars a day. Credit agencies are updated once a year. The people who are lending those amounts are doing their assessment and in real time. They're sophisticated. They directly talk to the utility in some detail and a lot of times, that information will flow much more quickly through the spreads that you're seeing than you'll ever see it written in black and white in a ratings

report.

YOUNG, Q.C.:
Q. So, the borrower phrase "follow the money"?

MR. BOWMAN:
A. Yeah, don't undermine—underestimate the ability of the people who are lending the money to do their own assessment and not just rely on Standard & Poor's (unintelligible) -

YOUNG, Q.C.:
Q. Thank you.

MR. BOWMAN:
A. - do the work for them.

YOUNG, Q.C.:
Q. A different area here I want to pursue, and it was last one you spoke of, and it's one that I think is going to bring us back to this room for a lot of discussions in the coming years and that's got to do with the CDM and the screening tests. And I posed a question to Ms. Langthorne of Newfoundland Power with regard to the use of, as you've proposed, the RIM Test, and I put it to her that essentially it's a conservative test in

that it can screen out a lot of CDM that can have positive impacts overall, but as you've described, there's winners and losers in that. And I'm just wondering, in the last discussion you had just as you finished your testimony this morning, your direct, you were talking about a balance or using it in combination with others. Do you have an example of where, from your regulatory experience, where it's been used with others to design programs? Because, and I will agree with you, by the way, we're facing a somewhat unique circumstance with a very large project coming on with high costs.

MR. BOWMAN:
A. Well, it's been frequently more than one test used. I was pulling up last night the Manitoba Hydro documents which we thought about sharing, but they have a copyright warning on them even though they've been filed in regulatory hearings, but they emphasize that they apply more than one test. If you can have a program or a portfolio program that have a positive RIM

result, a positive rate impact result, you can be relatively comfortable you can pursue those programs without harming anyone, having a win-win. If you don't, you have to look a little bit deeper to see whether you've got losers in that mix and how you're going to deal with that. Sometimes that's a program design element. For example, if the losers are simply people who can't participate because they're low income, well, the question is, how do we help those low-income people participate? Sometimes it's solvable, but often, it's a sign that you are driving up rates to participate in CDM. As I noted earlier today, that isn't even necessarily a problem if you're trying to acquire new power because acquiring new power might drive up your rates, too. CDM may be the cheapest source of new power which will drive up your rates, but not as much as the alternative of acquiring new power. That will fail a Rim Test, but it doesn't mean it's a bad decision because you need the power. But that's not where we are

today here either. So, there's a lot of situations where you can apply that test. It'll help you identify programs that should be slam-dunks, it can go forward and it's not a prohibition to other types of programs, but those other types of programs need to be considered for the distributive effects and that can often be extremely challenging as I noted with Synapse. And if I can just note one other thing there, one of the surprising things to me is the extent of enthusiasm, if I can put it that way, for CDM programing today on the system where the idea of running CDM programs is to get customers to do things they wouldn't otherwise do or wouldn't otherwise have incentive to do themselves. Well, a few years ago, ten years ago, pick your number, we had rates that were lower than they will be after this without mitigation and we had--benefits from conservation were higher because we could avoid Holyrood oil. Now, we're going into a situation where rates can be higher, absent mitigation, so customers

will already have a lot incentives to do things themselves without having to run a program and benefits will be lower because your exports are--the exports you can get are much lower, much less than Holyrood's oil was going to be. If anything, CDM would be less relevant in the future, CDM programing, (unintelligible). It will less relevant in the future than it would have been five or ten years ago. So, it seems surprising that now we're going to say, "Oh, there's this huge new opportunity from CDM." If anything, I would think the opportunity is less than it ever was.

YOUNG, Q.C.:

Q. It occurs to me, as you say, the Board might wish to apply judgment here. When you have a portfolio or suite of programs, and you might have some, I'm proposing this to you, you might have some that fail the RIM Test, still not that badly, but they provide generally significant energy savings, and they might be at times of peak, which makes them particularly attractive if those

opportunities are there. And you might have others that clearly pass the RIM Test. Would you see or have you seen places where they look at the overall impacts of a number of them and don't get too fussed about the fact that some might fail the RIM Test because overall benefits of the whole suite make sense?

MR. BOWMAN:

A. Yeah, absolutely. That's what I was talking about. These tests can be applied to a program or to a portfolio of programs. And often, the portfolio is—it's an art to design a portfolio that you assess because you need to take into consideration things such as, you know, quality of opportunity for different rate payers. Maybe there is a, you know, a regional aspect. You know, in Manitoba we face the situation where some customers have access to natural gas and some don't. So, if you design a program and you come up with some great numbers, but you look at it and you realize you've given a huge opportunity to half the province and the other half has nothing, you have to have think about those types of effects. You can also see it in cases where, for example, going back to Manitoba Hydro's example, they may have 30 programs. One of those is affordable energy program that designed for low-income customers and on its own it'll never pass a RIM Test because you simply have to supply much supports for getting low-income customers to participate. They can't do it themselves even with a great return. And so, that one may fail the RIM Test, but it's an important part of getting a portfolio to have, you know, equity in it that's needed to get board support across multiple groups, but once you put it together with the portfolio, you still have a positive set of tests and so you design a portfolio in that manner. That's part of the art of designing this.

YOUNG, Q.C.:

Q. And I guess my last question in this, in this connection, is with regard to the group that you represent, the Island Industrial

Customers, and broadly different characteristics from the bulk of customers who are likely to be able to avail of the CDM programs. So, if there isn't something there for the industrial customers, almost by definition, if there's less energy revenue, then the RIM Test, or sometimes called the "no losers test," could have a loser? Is that correct?

MR. BOWMAN:

A. Well, if they can't participate, they could end up being a loser. I don't, you know, definitely don't dismiss the opportunity provided by industrial CDM. Well, for example, one we know of is the capacity assistance.

YOUNG, Q.C.:

Q. Yes.

MR. BOWMAN:

A. Those are massively beneficial programs particularly in the situation that we're talking about, but you know, again, just because I had the document out last night, Manitoba Hydro gets a lot more relative

conservation from its industrial customers than it ever does from residentials. There much easier to access. The problem is that they're a very different design. They're very lumpy. For example, if someone is going a capital upgrade, you may have a huge opportunity to have them use a different technology, install some better equipment or something like that, but that only occurs that one time when they're doing the upgrade. That upgrade is then going to be in place for the next 20 years and you're stuck with that technology occurred. So, you want to capture those and I think that's occurred here. I think if you look back in the history of conservation here, there's one year that had a huge spike, about how much occurred and it was one industrial customer that had a plant upgrade or something of that nature going on and there was –

YOUNG, Q.C.:

Q. Yes, they're less about programs; more about being attentive to opportunities as they

arise.

MR. BOWMAN:

A. Yeah, yeah. Yeah, and often it's about showing--you know, helping people calculate a return and then, you know, they can go find the money.

YOUNG, Q.C.:

Q. Right.

MR. BOWMAN:

A. They don't need, you know—it's not about advertising or some of the other things that are—or training. You know, if you want to install a bunch of heat pumps in a province, you've got to have people who can install it. So, you need training. You need advertising. Industrial customers aren't that type of market. It's an entirely different focus, but the conservation opportunities can be significant, but they're—you don't have that many customers and so there may be very few for many years until you have the right one come along.

YOUNG, Q.C.:

Q. Thank you, Mr. Bowman. Thank you, Madam.

Thank you, that's my only question.
(10:15 a.m.)
CHAIR:
Q. Thank you, Mr. Young. Newfoundland Power?
MR. O'BRIEN:
Q. Thank you, Madam Chair. Good morning, Mr. Bowman. I only have one area for you, Mr. Young covered off the CDM quite well, I think, with your earlier testimony you touched on that. So I wonder if we could bring up, I want to look at Recommendation 5 just briefly and it's page 12 of your slides. And so that was your recommendation with respect to avoid over investment by Newfoundland Power in assets that do not produce economic output, Newfoundland Power should be directed to evaluate resource planning decisions based on consolidated interconnected island system marginal costs. My understanding is that that's what Newfoundland Power does right now. And if that is the case, would you agree with me then that there's really no need for a recommendation for them to do something they're already doing?

MR. BOWMAN:
A. Yes, that's correct.
MR. O'BRIEN:
Q. Okay, that's the only area I have for you, Mr. Bowman.
MR. BOWMAN:
A. Yeah, had we had an opportunity for RFIs, I think we probably would have been able to clarify this.
MR. O'BRIEN:
Q. I got that impression that you really never had that opportunity to ask that, so I just wanted to confirm that, okay. Thank you, sir. I don't have any further questions, Madam Chair.
CHAIR:
Q. Thank you, Mr. O'Brien. Consumer Advocate?
MR. FITZGERALD:
Q. Thank you, Madam Chair. We both have a couple of questions for you this morning, Mr. Bowman. I'll start, in a general sense. If I could look at your Slide 5.
MR. BOWMAN:
A. Yes.
MR. FITZGERALD:

Q. And this is kind of a contextual or philosophical question, I suppose, but generally do you believe that the Muskrat Falls project costs had been prudently incurred in the regulatory sense?
MR. BOWMAN:
A. I wouldn't have been able to make that assessment, it wasn't part of the scope.
MR. FITZGERALD:
Q. Sure. I guess we've heard Mr. Marshall, I think he's on the record in 2016 describing the project as a boondoggle. We are looking at a 12.7 billion dollar project. Is it reasonable to infer that perhaps some of the costs weren't prudently incurred?
MR. BOWMAN:
A. I think at the first instance it passes a smell test that there is, that the costs are higher than may have been available from some alternative types of development, but I think one has to be a little bit careful when you're building infrastructures that changes the nature of the system, you know, something like getting connected to the North American grid may be a huge benefit 30

or 40 or 50 years from now when one looks at the overall picture, those could be a massive leg up, and if you are really looking for long term, those transformations may be the thing that changes dramatically power prices forever on the island, effectively. Having said that, that's why I think the mitigation issues are massive because if those types of benefits exist in the very long term, the question is how to avoid hammering people today for what is, you know, a far in the future potential benefit that is very hard to quantify. So, you know, is it imprudent? It may not be imprudent over its life, but it is definitely of major concern in the first few years.
MR. FITZGERALD:
Q. Sure, fair enough and we've heard the 75 year horizon and the 100 year horizon at one point, I think, but in the short term with what consumers are facing, you know, and I suppose to put the question another way and it's a hypothetical, I guess, but if the project had to have been given regulatory

scrutiny, would 75 timelines be take in account in a regulatory sense to sanction a project like this?

MR. BOWMAN:

A. Well I think they would be taken into account, but I think there would be much more focus on the near term and mitigation aspects. I reference in my evidence the Manitoba Hydro's HVdc system which is developed in the '70s and is probably the key aspect of why Manitoba has some of the lowest power costs across the country today. It never would have been built without the type of supports that it received, that I discussed, including on things like effectively depreciation. This line was, it could not have been carried by rate payers in that day, it would not have been, I'll say in a colloquial sense, prudent. It would not have been prudent over any, you know, short-term or medium-term horizon of 10 or 20 or even probably 30 years when it was first built, but now 50 years later, it's the key piece of our infrastructure. People got together, though, and solved that

before it was ever put in place. They had the federal government come to the table through Atomic Energy of Canada who built it and leased it at a very low cost to Manitoba Hydro, for a long time, until Manitoba Hydro bought out the lease. Ratepayers paid every nickel of the project. There's no subsidy, but there was a timing difference and the timing difference was supported by a level of government who could see the long-term infrastructure benefits; particular in that case, the feds.

MR. FITZGERALD:

Q. And that's, I guess, the point that, you know, that's important. You mentioned the word "subsidy", in this case Mr. Marshall recently, when he was on the stand, indicated that the costs of Muskrat Falls are inescapable for ratepayers, the costs are hardwired to the ratepayers by legislation, and now we're going through this exercise of studying rate mitigation, but I take it, would you agree that rate mitigation is not subsidization?

MR. BOWMAN:

A. It could be that subsidization would be one way to mitigate rates, but it's not one that I think is necessary on its face if the range of options is broad enough. Unfortunately those ranges of options go into things like you just commented, that there's legislation that provides a certain set of rules, there is negotiation with counterparties that is outside this room, within those other spheres. It's not impossible to me that a thoroughly unsubsidized but carefully crafted project could not be designed in a way that didn't shock ratepayers and as prudent. But, you know, many of those aspects are outside of this room and what you're left with is if you lock in all of those aspects, you're left with a very challenging situation of trying to figure out how to not hammer ratepayers absence of subsidization. And you may end up with requiring subsidies because a good many of those levers of control that other jurisdictions have used to bring on line new projects are not available.

MR. FITGERALD:

Q. Yes, and I guess you're looking again fairly in a long-term sense that this all make sense 50 years from now, but, of course, we're facing the current obligations on ratepayers and the ratepayers are paying now for deals made by the shareholder, if you will, by government. There is no way out for the ratepayers, so, you know, whereas the costs are hardwired, if you will, so as a subsidization, when you look at this table, you mention that the 249 million foregone provincial benefits not from subsidies, lowering of costs, so would you agree that the characterization of the money that comes from government for ratepayer relief is not a subsidy?

MR. BOWMAN:

A. Yes, that was, I emphasized that in the evidence that if the conclusion is reached that the project as developed was, you know, is not economic, then it would be reasonable to assume that the party that developed the project, the owner, would be foregoing profits and dividends on an uneconomic project that's not a subsidy, that's just somebody develops something that doesn't make profits. You know, a regulatory framework is designed to best mimic a competitive framework where competition can't work because of things like natural monopolies, so best mimicking a competitor framework means somebody who develops something takes on the risks that the thing they developed isn't economic and if that's where you're best mimicking, then that party doesn't get to collect dividends from it or doesn't get to collect surplus energy sales from a project being paid for by another party.

MR. FITZGERALD:
Q. Fair enough, so ratepayers are stuck with the bill, they're going to pay the bill, so any relief from government could not really be characterized as a subsidy.

MR. BOWMAN:
A. I think that's fair and I also wanted to emphasize that in part because if the discussion is about whether Hydro is self-supporting, somebody saying I'll lower your

ROE so that your revenue requirement is lower and your rates are lower and that's a form of mitigation, would not be viewed by a credit rating agency in general, in my experience, as a subsidy. But someone saying I'm going to collect a big dividend and I'm going to write you a big cheque at the end of the year, the parent writing the crown a cheque at the end of the year, looks a lot more like a subsidy and the more that the parent is writing a cheque to the utility saying here's your money back, I think even just on the simple colloquial meaning of it, looks a lot more like that utility is not self supporting, it's requiring that cheque from the government every year.

MR. FITZGERALD:
Q. And I guess from your client's point of view, I guess, the Industrial customers, it probably is more relevant, I guess from Domestic customers as to how this rate relief is characterized, whether it's rate mitigation or subsidization, your competitors or your client's competitors

outside this jurisdiction might take a dim view of a subsidized rate.

MR. BOWMAN:
A. I don't think I have done the assessment to be able to characterize that. It has come up in other jurisdictions I've been in, but I have not looked at it from that perspective in this proceeding.

MR. FITZGERALD:
Q. Sure. Just moving on to another brief topic, in your experience in examining other utilities, have you had any experience seeing how performance based rates may affect their systems?

MR. BOWMAN:
A. I have had some dealing with performance based rate making in a few jurisdictions that I've dealt with.

MR. FITZGERALD:
Q. And do you have any comment regarding the effectiveness of it?

MR. BOWMAN:
A. Performance based rate making is a model for setting rates where rather than the details of, for example, operating costs or whatever

costs are included in the rate regime, rather than those being reviewed carefully by a regulator who tries to assess whether each one is prudent, instead you find a way to put the incentive on the utility themselves to keep those to a prudent level and if they do so, there's a degree of sharing where they can keep some of the added benefit of keeping their own costs down. It relies on the incentive within the utility to want to maximize their profits. It works fairly well for a private company that has an interest in maximizing their profits. I have not seen good examples of it working where a utility's priority is not necessarily maximizing their profits, which is why you won't find PBR very often applied to crown utilities because they don't necessarily have the same profit maximizing objective or drive, at least in general, as a private sector utility would. I would think that PBR may be something that is, you know, it's applied well at a distribution level, I'm dealing with proceedings in Alberta where PBR is being applied to distribution utilities. It may not work as well at a bulk power level, at the type of level that Hydro operates at, and if your interest is in what are the incentives on the utility, particularly for a crown, sometimes the best incentive on them to keep their costs down is avoiding having to come back for a rate increase and have a big public hearing. So sometimes the best incentive for them is not PBR but, you know, old school rate base rate of return regulation where, when the costs go up, they have to go through all of the costs and focus and procedures of a full regulatory review.

MR. FITGERALD:
Q. Okay, thank you, Mr. Bowman. I think Mr. Browne has some questions for you now.

BROWNE, Q.C.:
Q. Good morning, Mr. Bowman. There's been some discussion here of Nalcor Marketing Energy regarding greenhouse gas credits, are Industrial customers eligible for federal climate change initiatives based on greenhouse gas credits, do you know?

MR. BOWMAN:
A. I don't know, I don't have information on that.

BROWNE, Q.C.:
Q. So there's no study that you're aware of for Industrial customers on that particular issue?

MR. BOWMAN:
A. Nothing that I am aware of.

BROWNE, Q.C.:
Q. You stated in your evidence, you give comparative tables for electricity rates in various jurisdictions, residential rates, why are average prices across Canada in various jurisdictions relevant, why do these have significance?

(10:30 a.m.)

MR. BOWMAN:
A. Well they're relevant to give a sense, this slide is not coming up on the screen, they were relevant to give a sense of what five cent power and twelve cent power looks like, I think. I don't know if that's always intuitive to people, so we thought this gave a useful picture about the extent to which,

you know, this province is not just facing a rate change, it's facing a significant change in the competitive stacking order.

BROWNE, Q.C.:
Q. Some of these jurisdictions have alternative sources of heat energy that people can go to, as opposed to electric heat?

MR. BOWMAN:
A. Yes.

BROWNE, Q.C.:
Q. So does that make them less significant and less relevant if you're into a jurisdiction such as this one where 70 percent of Newfoundland Power's customers or 70 percent of the population I guess generally, are using electric heat.

MR. BOWMAN:
A. Well electric rates are a much more acute factor where you don't have alternative sources of supply. With companies that I deal with, for example, Manitoba Hydro's Industrial base, a significant part of it is out of the natural gas service area anyway, it's up in the mines, up North, for example, so sometimes it's not a jurisdiction by

jurisdiction thing, it's a particular location, but definitely for, for example, if you're looking at the Residential comparison, the fact that some of these need to use that power for electric heat would be relevant when one is thinking about the overall impact on bills.

BROWNE, Q.C.:
Q. In terms of that some have presented here provincially, indeed at the Muskrat Falls Inquiry, stating that electricity prices in this jurisdiction are artificially low, do you have any evidence that electricity prices in this jurisdiction are artificially low?

MR. BOWMAN:
A. I haven't heard that testimony and I'd be interested to know where someone goes to come up with that conclusion. I can't think of many aspects of Hydro's revenue requirement that are artificially low or subsidized or not fully recovered from customers.

BROWNE, Q.C.:
Q. So you wouldn't agree with that comment that

electricity prices in this jurisdiction are artificially based or artificially low?

MR. BOWMAN:

A. Well I would need to know where the assertion is coming from and what they're referencing because it's not apparent to me in any significant way where somebody would come up with the conclusion that they're artificially low. At most, for example in British Columbia, the BC Hydro for years had a notional income tax included in their structure because the government somehow came up with an idea that BC Hydro was uncompetitive to other alternatives because it didn't have to pay tax and other people did, so they sort of impute an income tax in it, so I guess someone might say they're artificially low because Hydro doesn't pay income tax. Beyond that, although I'll say that's pretty common across the country, there's a lot of crown utilities don't pay income tax, beyond that, I can't imagine a part of Hydro's cost structure that immediately comes to mind that isn't fully recovering the costs of producing the power.

BROWNE, Q.C.:

Q. Sure, and there was no evidence presented to backup the statement, it was just sort of an empty statement made in a submission. Do Industrial customers in this jurisdiction practise conservation and demand-side management?

MR. BOWMAN:

A. Well absolutely any customers responding to the economic signals it receives, Industrial customers are usually a bit more attuned to that than others because their bills are that much larger, so when they hire professional engineers to design elements of their plant, they will always look at what the appropriate design is and trade off things like, you know, low loss transformers verses regular loss transformers, for example, based on the price signals they're receiving. So in that sense, absolutely they're considering conservation and where there are savings and also things such as demand response programs where they're clearly working with Hydro to conserve resources at peak times.

BROWNE, Q.C.:

Q. Thank you very much, Mr. Bowman.

CHAIR:

Q. Does that conclude your questions, Mr. Browne?

BROWNE, Q.C.:

Q. (Mr. Browne nods in the affirmative).

CHAIR:

Q. Ms. Greene?

GREENE, Q.C.:

Q. Thank you. Good morning, Mr. Bowman. If you could go to Slide 10, please, of your presentation. In Recommendation No. 2, you recommend that Hydro's equity target should be revised to 20 percent or lower, and in your evidence you talked about the impact of a 20 percent target which would be a reduction from the current target of 25 percent. One, have you done any analysis that would allow you to make a recommendation as to what that equity target should be?

MR. BOWMAN:

A. No, and I would say that if, as we've gone through this and listened to the evidence, I

think even that recommendation I would sort of refine a bit and not necessarily suggest that a 25 percent long-term target be abandoned, but that one, may want to keep that as a roadmap target, but during this period where we're trying to absorb these rate impacts and deal with the mitigation, one might be satisfied not making that type of progress towards that target that's assumed in the graph that's on, I think the previous page. That may be achieved not necessarily by setting your targets lower, but by setting your ROE will be lower so you simply won't make ground on that during some period, five years or ten years or something.

GREENE, Q.C.:

Q. And I understood that, I guess I wanted to explore with you your recommendation was 20 percent or lower, how do you think would be an appropriate way to determine what that interim ROE should be?

MR. BOWMAN:

A. Well I, in sort of further discussing this, I think if there were—if there were a change in policies such that the ROE was not set the same way, but the ROE was set in some way that had a benchmark to a different standard and I think probably we both recall that the ROE target in the past years was much lower than this before the policy was changed. I think 3 percent comes to mind. That may say that for the next few GRAs, if you like, Hydro will operate with a much lower return built into its rates and as a result, it simply won't make that much progress towards the 25 percent. Would it go backwards, it might go backwards if it's building a bunch of capital because your denominator is also growing, so you know, if it went from 19 now down to 17 or something, because your denominator grew and your 3 percent wasn't enough to keep up with that, but that the picture turned around, as you had some period, like I said probably five to ten years out, where you go back to the ROE regime that exists now, if that's the sort of long-term intent, then I think you could look at that and say are we really troubled by 19 going to 17? You know,

remember, I'm coming from a place where Manitoba Hydro is going down to 12 or at one point was thinking 9 as part of it absorbing a big project. So I just think that, I wouldn't—it's not that I would turn 25 percent as a sacrosanct target, 20 percent as a sacrosanct target with the pedal to the floor trying to get there. I would say take the foot off the pedal, see where you end up, it it's a little lower than 20, if it's a little lower than even the 19 that is there now, so be it, as long as it shows that it turns around.

GREENE, Q.C.:

Q. And I was interested in how, did you have any recommendation how that analysis would be done which probably is a qualitative judgment, I suppose, to determine what the appropriate ROE target should be in the interim to assist with rate mitigation. You're not making a specific recommendation for the Board to recommend to government -

MR. BOWMAN:

A. No, and I'm not saying it should be 17 verses 18 ½. But I am saying that, you

know, were it up to me to balance all the different things in here, I would be encouraging the Board or encouraging government to relieve the ROE standard that's in place to allow the Board to assess an ROE against some different standard, for example meeting some interest coverage targets, making sure Hydro can pay its bills, but not sort of heck of a lot more than that, for some period of time that could be defined that the period in which we're really focused on, key mitigation aspects, like I said, five to ten years. And Hydro could probably very easily run, I'm sure Hydro has the capital plans that show ten years of capital spending, it could very easily run its models out to there and show what happens to its equity ratio and what it takes to turn that around when that's done. We do it all the time with Manitoba Hydro.

GREENE, Q.C.:

Q. So do you see that as a role for the Board or a role for the government and Nalcor Hydro to determine how low, how long can we

go?

MR. BOWMAN:

A. I would see it as a role, absolutely for the Board and partially because of the other criteria we discussed, which is Hydro's self-supporting status. If this Board has its hands tied, the degree of confidence that somebody can have in whether conditions on the ground will be responded to, will be lower because they're relying on policies that are written in stone or require political decisions. I think if you pull out the Standard & Poor's criteria document, it's a good example, and you look through it, they say that it's beneficial to the assessment of self supporting status that a utility has a competent regulator who has significant levers of control and gives lenders confidence that they will respond to conditions as they arise and so the less constraints you put on a board and the more that it builds creditability that the utility will continue to pay its bills and it will respond to conditions, I think the better it is for all involved.

GREENE, Q.C.:
Q. So you would recommend that the government repeal or remove the Order in Council direction setting Hydro's ROE and give the ability back to the Board to make the appropriate decision?
MR. BOWMAN:
A. Yeah, I think that's fair.
GREENE, Q.C.:
Q. I also wanted to ask you a little bit about Recommendation No. 3, which you really haven't talked about today. There you recommend broadening the scope of regulation and you refer to the unregulated aspects of Nalcor, such as Lower Churchill Project and Nalcor Energy Marketing, and I wanted to talk to you about what you actually meant by that recommendation. With respect first to the Lower Churchill Project, what is the nature of your recommendation? Right now, all of the Lower Churchill Project is unregulated and what are the Industrial customers recommending first with respect to the Lower Churchill Project?
MR. BOWMAN:

A. Well this recommendation is housed in a section on credit ratings and equity ratio and it arose from the assessment of this thing we just talked about, which is the more confidence and more power that this Board has, the more levers of control, the better off you're going to be for the perception of independence outside the province. But ignoring that, were it in this section or were it in a section on regulation, I think Liberty set out the case very well that when you have a set of costs being paid for by ratepayers who are captive, you normally have a regulator who ensures those costs are reasonable. Those costs might be operating costs; they might be ongoing capital additions, for example. I can't see an obvious reason those wouldn't be part of an overall regulatory assessment for the Lower Churchill Project and any aspect of assets providing services to ratepayers.
GREENE, Q.C.:
Q. So with respect to that, that would be the future operating and maintenance costs for

the Lower Churchill Project as well as future capital, would it?
MR. BOWMAN:
A. It would include at least those aspects. When people say something is regulated, they can mean a lot of different things. They can mean assets regulated, they can mean costs regulated, they can mean all sorts of things. I don't know that, you know, Hydro is regulated, the regulated portions of Hydro are a regular, there are a number of aspects here and some others even more broadly and things like issuing debt, for example, I don't know whether the Lower Churchill Project and the parts of it dealing with financing agreements that are locked in stone and have complicated counterparties and agreements that were arrived at in the past, I don't know that there's a lot of reason to have that, for example, assessed by the Board or any sort of issuance of short-term debts or something of that nature, I don't think those are the key focus. Another aspect you might talk about is sort of how the operations are

done, you know, we know this Board will receive reports on Hydro is managing its water, for example, in its reservoirs and the risk its taking on things, I haven't looked at whether that's an aspect of the Lower Churchill Project that merits having regulatory review. I think O&M costs and capital, normal capital, are pretty obvious things that would be included. Beyond that, I think there would need to be a bit more thought.
GREENE, Q.C.:
Q. Okay, and with respect to Nalcor Energy Marketing, what is the extent of your recommendation there with respect to regulation?
MR. BOWMAN:
A. Well I only reference it in regard to an example of another place where ratepayers are effectively paying the cost, but also absorbing the risks. I think there was some very—I did read the transcript in regards to this topic and I think there was some very good testimony given that emphasized that one doesn't need to—just because you have

regulation of a topic doesn't mean that you need to be in the nitty-gritty of how fast paced events occur, if you like, just like this Board isn't in the nitty-gritty of how fast paced decisions on water are made in with regulation of Hydro. Manitoba Hydro manages an energy marketing aspects that are under the jurisdiction of the board. I can't recall us ever doing a prospective, much less retrospective review of the trades. There's some high-level reports on them, but there is review of risk management practices, the degree of risks that's taken, the degree of, you know, trading exposure, losses, risk. We had a fairly major hearing in Manitoba in about 2010 about risk management in hydro that included a lot of assessment about, you know, their decisions center into a trade to, you know, buy and sell, for example, and their approaches to that and the board has weighed in on those aspects and I think that's, you know, to the extent that all that is on ratepayers' backs, it's only reasonable that captive ratepayers have some aspect of regulatory,

independent regulatory control that they can rely on.

(10:45 a.m.)

GREENE, Q.C.:

Q. Nalcor has suggested that there's transparency and that is the, could be an adequate substitute, I take it from your response to my question that you wouldn't agree that that provision of information alone would be adequate to protect the interests of the ratepayers?

MR. BOWMAN:

A. No, and neither is the argument, I think, that it's a crown so it only operates in the public interest. I think if you applied those same standards, you'd say why are we regulating Hydro at all?

GREENE, Q.C.:

Q. Right, okay. I'd like now to turn to another topic and I want to go to page 5 of your report, page 5 of the InterGroup Report, and I wanted to refer to lines 26 to 28 in particular. It's in the context of the significant increase that Industrial customers are facing, and you mentioned in

lines 26 to 28, that rate shock can be considered to occur when increases exceed 15 percent a year, and I wanted to ask in your experience have you, is there a threshold around an amount of a rate increase that caused concern to regulators so that they would take actions to try to smooth the rate impacts over a longer period of time. In this sentence that I took you to, you say that's a 15 percent, and I wanted to ask in your experience is that what you have seen applied by regulators in looking at rate smoothing mechanisms?

MR. BOWMAN:

A. Yes, we've seen a few different cases. It's a bit of a topic of beachheads, if you like, it's nice to have a beachhead which says, you know, there should be a fairly high threshold for a hydro-based utility to need rate increases above inflation, for example, you know, there's reasons, I think most of it is costs are locked in, so if there are increases above inflation, then you know, they would have a much higher standard to justify. You might think about some other

levels above that that increase the focus, but there is a fair number of examples where people say getting above 10 to 15 and 15 is often referenced, 10 to 15 percent rate increases in a year is in the territory of rate shock and you might be seriously considering smoothing at that level that even if your revenue requirement is requiring, you need to go there looking at some more creative options to avoid needing to impose rates above that level is necessary to protect customers.

GREENE, Q.C.:

Q. The Liberty report indicates that if all of the rate mitigation that they identified is made available, the increase would still be, at least for Residential customers, we'll talk about your Industrial increase in a moment, would be at least 35—would still be in the range of 35 percent. That type of increase, in your view, would prompt or should prompt, if possible, a rate smoothing approach?

MR. BOWMAN:

A. Yeah, that's a very concerning level of rate

impact.
GREENE, Q.C.:
Q. And you've mentioned it's at 15 percent here in your report and in your response you indicated you have seen discussion around an increase in the 10 to 15 percent range in one considered to be rate shock, did I understand your –
MR. BOWMAN:
A. Yes, 15 is definitely the outer range of that. There are a lot of jurisdictions that have referenced 10 that I have run across in my career, but the outer one that I recall being used as a standard is 15 percent.
GREENE, Q.C.:
Q. And the last area that I wanted to question you on was to deal with the Industrial rates and there, while we have it, you indicate what the proposed increase would be, the 5.22 cents in 2019 and my question there, because your reference was to your source was to the 2018 Cost of Service Application which was filed back in 2018, but it does not include the recent increase of October 1, is that correct?

MR. BOWMAN:
A. My understanding is it wouldn't include the recent increase or other RSP changes that are expected now, but also the 12.44 is based on a certain cost of service methodology assumption which is not the same as is ultimately coming to the Board as part of a settlement, so it was just the one set of numbers on the board, but, you know, we already know that those are—they're not going to be perfect; they're going to keep changing.
GREENE, Q.C.:
Q. So do you have any indication what the current rate is on October 1 that would be comparable to your 5.22?
MR. BOWMAN:
A. I don't have it for the class, this is averaged across the class. I have it for one of the customers within the class because they're low-profile matters, you have them mixed with the amount of energy and then when you solely divide by the energy it matters their load factor. I can run the number for you, but I don't have –

GREENE, Q.C.:
Q. The increase overall was 11.2 cents, but the average increase to Industrial customers as of October 1, so can we—so it would be higher by—and you're only using it for illustrative purposes to indicate where we are, so if you—so it's slightly higher now than what you have in that report, presumably.
MR. BOWMAN:
A. Yeah. Although, I have to admit I'm not sure, now that I'm looking at it, I'm not sure that this, the number that's cited here did not take into account that expected 2019 final impact, so I would want to check to confirm that this doesn't, it doesn't have that built in.
GREENE, Q.C.:
Q. Okay. Now I wanted to turn to the information, the helpful information that you provided which was a report from Hydro Quebec and here, Madam Chair, I would note we haven't marked the exhibit and it might be appropriate to mark it in case it needs to be referred to in submissions or later in

the report.
CHAIR:
Q. I will mark it as an information item.
GREENE, Q.C.:
Q. Exhibit 1 or PW, PB1.
CHAIR:
Q. Okay.
GREENE, Q.C.:
Q. And again, this was used to illustrate from your perspective where the current industrial rates are, you have already addressed some of the questions that I had, you indicate that your class of customers is generally in the large power users in the very last column, so we would be looking at the current of 5.61 on this chart.
MR. BOWMAN:
A. Yeah, that's pretty close and that usage level is not, you know, it's not far off the sort of middle consuming customer of the three.
GREENE, Q.C.:
Q. And you've indicated that without mitigation your rate will rise to an excessive 12.4 cents a kilowatt hour which would bring you

certainly to be the highest for the Industrial rates that are shown here on this page, is that correct?

MR. BOWMAN:

A. Yes.

GREENE, Q.C.:

Q. This is a reflection of rates as a rate for one, 2019, do you have any information as to where the future rates would go in other jurisdictions because the 12.4 would be a future rate for 2021, so to compare your forecast rate without mitigation in 2012, do we know where the rates would be in the other jurisdictions at that point in time?

MR. BOWMAN:

A. I don't know that any of them have rate approval through 2021 that I would know of. I do know that in respect of Manitoba, which is the jurisdiction I've most recently been working in, there is a significant effort to keep the rate impacts there below about 4 percent a year, so that, you'll see 4.6 percent there is the number and 4 percent a year is likely to be the outside range of what's going to be pretty consistent annual

rate increases as these new projects are being absorbed. I know that when we're doing rate comparisons in Manitoba, the Industrial customers in other jurisdictions will often be sending over notes about commitments from other jurisdictions not to raise rates, for example, I don't believe Quebec raised rates this year and I think there's some sense that they be stable for some period of time.

GREENE, Q.C.:

Q. So in your opinion the 12.44 cents obviously would be if not, would be among the highest for the Industrial rates in Canada, is that correct?

MR. BOWMAN:

A. Yeah, I think it's a fair conclusion it will be among the highest.

GREENE, Q.C.:

Q. Thank you very much, Mr. Bowman. Those are all the questions that I have, Madam Chair.

CHAIR:

Q. Thank you, Ms. Greene. Mr. Coxworthy, anything on follow-up?

MR. COXWORTHY:

Q. No questions arising, Madam Chair, thank you.

CHAIR:

Q. Thank you. Any questions Commissioner Newman? No. And I don't have any questions either. Thank you so much, Mr. Bowman, nice to see you again. Our schedule for tomorrow is to reconvene at 9 a.m. We have six presentations from members of the public. The Board Secretary should have that schedule if you don't have it already, it should be provided to you fairly shortly and it will be available on the website today, so we'll reconvene to tomorrow morning at 9 a.m. Thank you so much. Safe travels home, Mr. Bowman.

Upon conclusion at 11:57 a.m.

CERTIFICATE

I, Judy Moss, hereby certify that the foregoing is a true and correct transcript in the matter of Reference to the Board, Rate Mitigation Options and Impacts, Muskrat Falls Project, heard on the 17th day of October, 2019 before the Newfoundland and Labrador Board of Commissioners of Public Utilities, 120 Torbay Road, St. John's, Newfoundland and Labrador and was transcribed by me to the best of my ability by means of a sound apparatus.

Dated at St. John's, Newfoundland and Labrador this 17th day of October, 2019

Judy Moss

C

E