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 7, 2019

PRESENT:

The Board:

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

Board Counsel / Staff
Jacqueline Glynn, Board Counsel
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

Witnesses:

Synapse Energy Economics, Inc.
Robert Fagan
Dr. Asa Hopkins
Melissa Whited

(9:00 a.m.)
CHAIR:
Q. Good morning, everybody. Happy Monday. I understand there's no preliminary matters, so I guess we'll go straight to you, Ms. Greene, and you can introduce the first presentation for today.
GREENE, Q.C.:
Q. Thank you, and good morning, Chair and Commissioners. I'd like to first begin by introducing the panel. Start with Bob Fagan. Mr. Fagan, could you please introduce yourself and give a very brief outline of your background and experience as it relates to the work you did for the Board for this reference.
MR. FAGAN:
A. Good morning, everyone. My name is Bob Fagan. I'm a Vice-President at Synapse Energy Economics. I've been at Synapse for about fifteen years. I have a Mechanical Engineering Degree and I've been an Engineer and an Energy Analyst for onward of thirty years now working in this field. As it pertains to this reference, my primary

qualifications have to do with modelling of the economic aspects of electric power systems, and I also have an extensive background in energy efficiency or conservation and demand management, and the general nature of wholesale market constructs throughout the United States, and extensive experience working in the Maritime area, primarily resource planning in Nova Scotia and Prince Edward Island jurisdictions.
GREENE, Q.C.:
Q. And have you presented as an expert witness in other proceedings?
MR. FAGAN:
A. Yes, I've been an expert witness roughly nineteen states at the Federal Energy Regulatory Commission and in five provinces – I think six provinces including this province.
GREENE, Q.C.:
Q. Thank you. Dr. Hopkins, could you similarly give a brief outline of your background?
DR. HOPKINS:
A. Sure. Good morning. My name is Asa

Hopkins. I'm also a Vice-President at Synapse Energy Economics. I've been at Synapse for almost three years. My training is as a physicist. I have worked in energy efficiency for the US Federal Government at the US Department of Energy, and I ran what's called the State Energy Office, equivalent to some portion of the Ministry here for the US State of Vermont for five years or so, including developing energy policy across energy supply, energy efficiency, electrification, and overall decarbonisation efforts for the state, including crafting its comprehensive energy plan. Since moving to Synapse, I have worked on electrification and decarbonisation projects and energy efficiency in a number of different states. I've testified as an expert witness in Vermont and in Quebec, as well as now here today.
GREENE, Q.C.:
Q. Thank you, and Ms. Whited.
MS. WHITED:
A. Good morning. My name is Melissa Whited.

I'm a Principal Associate at Synapse Energy Economics. I've been at Synapse for ten years. I work extensively on electricity regulation topics, as well as rate design, and I've testified before seven state commissions and the Federal Energy Regulatory Commission. I've also worked on rate design issues in Nova Scotia, Prince Edward Island, and Quebec, in Canada, and now also in Newfoundland. I've presented on rate design issues before the National Association of Regulatory Utility Commissioners in the United States, and I have a Masters of Arts in Agricultural and Applied Economics, as well as a Masters of Science in Environment and Resources.
GREENE, Q.C.:
Q. Thank you. Before we begin your presentation, I understand, Mr. Fagan, that there are two corrections you'd like to make to your report.
MR. FAGAN:
A. That's correct.
GREENE, Q.C.:
Q. The first I'd like to bring up is page 60 of

your report.

MR. FAGAN:

A. Yes.

GREENE, Q.C.:

Q. And could you please outline the correction you would like to make?

MR. FAGAN:

A. Yes, the correction is in the heading for Figure 24. Instead of the word “residential”, that should be “commercial”.

GREENE, Q.C.:

Q. The second correction I understand is on page 149 of your report in Table 76, is that correct?

MR. FAGAN:

A. Yes, that’s correct, Table 76, and this pertains to the second row, the value listed there for annual heat pump electricity use. Instead of 29,613, that value should be 10,768. We made this correction in response to an informal inquiry by Newfoundland Power, their first informal inquiry response question, and I just neglected to get this changed for the September 25th revision to the report.

GREENE, Q.C.:

Q. Thank you. If we go now to your presentation, as you just mentioned, your report was revised on September 25th of this year and your presentation essentially reviews your findings in your report, is that correct?

MR. FAGAN:

A. Yes.

GREENE, Q.C.:

Q. First if we could begin, I would like you to outline what were the areas or issues on the reference questions that Synapse was asked by the Board to review and analyze?

MR. FAGAN:

A. Yes. This slide outlines the scope of our analysis. The reference questions asked us to determine whether or not it’s more advantageous to maximize domestic load or to maximize exports. Essentially in our modelling, our electrification scenarios look at the effect of increasing domestic load, and our conservation and demand management scenarios cause consumption to be lower and, therefore, exports sales to be

higher in the province. The second question had to do with the energy and the capacity balances from Muskrat Falls Project required to meet load and what would be remaining for surplus energy and capacity. We directly compute in our modelling processes what remains for export from Muskrat Falls after accounting for the Island and Labrador load requirements, and the overall resource capabilities in the province. The third question asked about the potential electricity rate impacts associated with the options in question one, and we compute these impacts from all of our scenarios relative to a base case where no electrification or no CDM measures are taken. Because of the material effect on consumption associated with electrification or CDM, we also looked at the corollary effect of a reduced oil and gasoline use in the electrification cases, and the bill impact effect, average customer bills across all of our scenarios.

GREENE, Q.C.:

Q. If we could move then to a summary of your

overall findings with respect first to your work that you did on growing revenue opportunities?

MR. FAGAN:

A. Sure. Our summary finding, there’s no magic bullets for mitigation arising from electrification or increased export sales. These are all predicated on customer actions which occur slowly over time, but can have significant effects in the long term. Electrification is the biggest factor that would mitigation rate increases because essentially you sell more energy to cover the fixed cost associated with the Muskrat Falls Project. You know, we do note that the oil and gasoline savings that arises from electrification is sort of the new money that’s available to help reduce the bill effect for customers. We definitely note that these benefits can be distributed unequally depending upon who’s in a position to electrify and in which sectors. So programmatic efforts and policies can help to address any inequities that might otherwise result when thinking about who

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would benefit from electrification. We also find that CDM and demand response in multiple forms is particularly important, given the concerns about possible capacity expansion costs in the province. CDM will reduce peak consumption and it will also reduce the peak megawatts, so it avoids those potential expansion costs and it also has the effect of increasing export sales. It can exacerbate the rate increases, but it can result in lower bills. Essentially, customers pay bills. If the rates are higher, but their overall consumption is lower, their net bills can be lower.

GREENE, Q.C.:

Q. Can we carry on to the next –

MR. FAGAN:

A. Continuing, rate design and existing policies and the Muskrat Falls Projects surplus, we did find that rate design could be a potentially powerful tool to shape consumption patterns and improve the outcomes for customers. We did find that the lower cost and the simpler implementation of smart electric vehicle

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charges in lieu of a full scale automatic metering infrastructure to monitor hourly loads would be least regrets, but it is possible that a broader application of Time-of-Use rates using a set of automated metering infrastructure to measure on an hourly basis could potentially be economic, depending upon some of the details of exactly how much it costs and how those benefits accrue across the different rate classes. We critically note the importance of both the federal and the provincial policies to help. The policies, as we outline in the report, specifically address fuel switching, energy efficiency, and rebates for electric vehicles, all of which will directly impact the electrification and the CDM costs and effects that you see in our report. We do note that the overall surplus from Muskrat Falls Project is of sufficient quantity to fully support the higher level electrification efforts that we model in our analysis. We note on Reference Question 3, that we do show rate and bill impacts for all of our model scenarios.

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GREENE, Q.C.:

Q. You've already outlined that you looked at the potential for export sales, and your finding is that it is better to increase electrification in the province because revenue is higher from internal sales. I was hoping to expand and explain your findings on expert sales?

MR. FAGAN:

A. Yes, that's correct, essentially you can obtain increased revenues if you sell more energy, more electricity, internal than selling on the export market primarily because the export market prices are relatively low, they don't represent firm capacity and energy transfers. It's mostly more of a non-firm short term energy market. We did look at whether or not it's better if export market prices are particularly higher. Things do look much better if export market prices are higher, but we don't have any particular basis to think that the export markets are - prices for export markets are going to be from the medium level that we model in our analysis. We do

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note that when you do maximize export sales if you were to do electrification, the total amount of export sales, you know, could rise to more than 200 million dollars a year by the end of the decade, and that includes the effects of both the Muskrat Falls and recall energy export sales. Those export sales are much lower, but you electrify rising to 141 million by the end of the decade, but what's coupled with the minimal revenues from export sales is much higher revenues from actual electrification of revenue streams within the province. Our modelling takes into account the combination of both CDM and electrification effects, and the overall volume and the overall pattern of sales will vary depending upon which combinations of electrification, CDM, and rate design we see. As I just noted, we do show sensitivity on market prices that you can see increases export revenues on the order of 75 million dollars higher by 2030 relative to our base case on export sales if prices were to be higher, but also note that the other side of that envelope, if export market prices were lower, you would see a reduction in the revenues received relative to our base case.

GREENE, Q.C.:

Q. How did you determine the appropriate forecast of the export pricing to use in your modelling?

MR. FAGAN:

A. We received confidential data from Nalcor on a forecast of export market prices. Those export market prices are forecast for essentially the New England and Nova Scotia markets through export paths by way of Quebec, and export paths by way of Nova Scotia. Those export market prices are generally pegged to the price of electricity in the North Eastern US, especially in New England, and those prices tend to be tied to the effect of natural gas prices on electricity prices in that region. The numbers that they provided are not unreasonable. If anything, electricity prices in the North Eastern US are likely to be lower than what we may see right now because there continues to be downward

pressure on those prices due to the availability of less expensive natural gas and due to the increasing level of both solar and wind resources in the North Eastern United States, all of which put a damper on the market prices seen in that region.

(9:15 a.m.)

GREENE, Q.C.:

Q. So as I understand your answer, you're starting point were the forecast provided by Nalcor, but you applied your own judgement and analysis to determine if they were reasonable and representative of the market, is that correct?

MR. FAGAN:

A. Yes, we do think that they are reasonable. We did look at fundamentals from the US Energy Information Administration, annual energy outlook, which forecasts both short and long term prices, and the numbers which are more detailed from Nalcor do represent, in our opinion, a reasonable indication of what prices are going to look like in the future.

GREENE, Q.C.:

Q. Okay, you've already mentioned that you not only looked at the impact on rates of increased electrification, and CDM, and export markets, you also looked at the impact on customer bills, and can you explain why you did that and what it showed?

MR. FAGAN:

A. Yes. Essentially, with increasing levels of CDM, either promoted by a programmatic expansion or prompted by customers doing their own actions now in the anticipation of higher prices, that has a significant effect on the average annual consumption for a given customer. Certainly anyone who electrifies, be it at the residential or at the commercial institutional level will see significant increases in the consumption at their facilities. Those two effects means that it's critically important to also look at the quantity consumed, in addition to the price that applies for a given customer. That's why we looked at bills, and in the case of electrification scenarios, it's also important that it serves an additional well

of savings available from reduced expenditures on oil and gasoline. Though the reference questions clearly say rate mitigation, technically and economically it's critically important to also look at the bill effect associated with changes in consumption, not just the rate effects.

GREENE, Q.C.:

Q. In your slide here with respect to summary findings for rates, you reference a Synapse based case. Can you just briefly explain what that is?

MR. FAGAN:

A. Sure. Our portion of responding to the reference questions had to do with looking at changes on the demand side, increased sales through electrification, or increased export sales in part through CDM to make the increased energy available for export. So everything that we do is relative to a reference case, a reference load forecast, and a reference level of export sales, and a reference level of electrification. So all of our scenarios are compared to that reference level, so they're not absolute.

What we're able to show clearly, for example, is in the high electrification scenario rates would be 1 cent per kilowatt hour lower by 2030, but what we don't show or we don't take on the task, is what is the absolute rate in 2030 because that will depend on what the total eventual revenue requirement is, and there's a number of things that both Liberty has looked at, and that still undergoing analysis suggests what that revenue requirement would be. So our focus was just to tease out the effect of the CDM, the effect of electrification, the effect of rate design, and how it influences the pattern of consumption, the pattern of export sales, and the resulting revenues that attach to those different patterns of consumption or sales.

GREENE, Q.C.:

Q. Is there anything else you'd like to say for your summary findings on rates and bills in Slide 8?

MR. FAGAN:

A. The last thing, we do indicate that it's the combination of scenarios that maximize

electrification, but at the same time maximize CDM effects, in particular reducing the peak load exposure that the province will see. We do make a core assumption that flows from Hydro's Marginal and Generation Cost Study, that basically there is always value to reducing the peak load in the province. On the margin, there's both a short and a long term need for capacity. We do not directly look at reliability and the potential for the LIL to be out of service, but indirectly in assigning value to all peak shaving efforts, be they directly from conservation and demand management measures, such as heat pumps or shown improvements that reduce peak, or be they flowing from demand response, which is a shorter term reduction of peak, both of those peak shaving actions come with a value of capacity that we use the number that's in the Marginal and Generation Cost Study, and that's a critically important point to make to support our findings that it's the combination of both electrification and CDM that provides the best benefit for

customers.

GREENE, Q.C.:

Q. One of the reference questions also asked the Board to review the amount of capacity and energy that would be available for internal use and export use, and your next slide addresses that question. Can you please review your findings in that area?

MR. FAGAN:

A. Yes. The modelling tool that we used, which is the same tool that Hydro used, the PLEXOS Production Cost Modelling Tool, is essentially a way to keep track of the generation, the consumption, and the flows in an economically and technically correct manner. So what we find is that if you look just at Muskrat Falls, you cover the requirements on the island, that you end up with surplus energy availability that ranges on the order of 1.7 to on the order of 2.1 terawatt hours, and that's what the beginning portion of this slide shows, which comes from Table 41 of the report. At the same time, Muskrat Falls is on the order of 5 terawatt hours, recall energy quantities

are on the order of 2 terawatt hours, so depending upon how you do the basic energy balances, the total revenues, the total quantities available for export sales actually ranges up to 3.5 terawatt hours if you take both recall and Muskrat Falls into account, and that's essentially what this table is just showing that the range of surplus for export sales depends on whether or not you count both recall and Muskrat Falls, or you try to look just at Muskrat Falls.

GREENE, Q.C.:

Q. One of your principal findings is that increased energy usage or electrification is the most beneficial opportunity to increase revenue to offset the rates. Could you on the next slide just give a brief overview of what your analysis showed for the electrification potential?

MR. FAGAN:

A. Yes. We focused on the electrification potential in two sectors; buildings and transport. What this slide shows is that by 2030, under certain assumptions for basically penetration of electric vehicles and conversion of electric resistance heating – I'm sorry, conversion of oil heating to either heat pump, or in some cases electric resistance heating, could add up to 600 gigawatt hours per year, and that's on a provincial basis of on the order of 9,000 gigawatt hours per year. The savings that you see from this essentially stem from oil savings, which ramps up to on the order of 244 million dollars per year by 2030. The direct contribution to revenues associated with this electrification, taking into account the costs of incentives for heat pumps and the cost for electric vehicle charges, for example, ranges from in the early years to 67 million dollars up to on the order of 134 million by 2030 for the high electrification case. I'm sorry, that was the direct contribution to revenues as the slide indicates. The net mitigation is on the order of 10's of millions of dollars from the high electrification scenarios, reaching upwards of 50 million dollars net by 2030 for the high scenario. This slide

represents the peak load additions associated with electrification. I'll note that these are the additions you see on peak. These totals are not necessarily coincident with the island's winter peak. That coincident is a little bit lower than the 147 you see here. It's more on the order of 100 megawatts. This just shows the variation in the addition to peak seen across the different types of electrification by transport or by building sector.

GREENE, Q.C.:

Q. You've already mentioned that you also studied Conservation Demand Management, and can you explain why that was important here because again it seems almost counterintuitive if we need to grow revenue, why do you focus on reducing demand? So can you just briefly explain that and what you found?

MR. FAGAN:

A. Sure. The primary value in the CDM, and the demand response, is the ability to shave peak. If you retire Holyrood, you have a

situation where you potentially have a capacity problem on the island, thus any demand side resource that can contribute to mitigating that capacity problem has value. Now it also saves energy and it saves energy primarily during winter hours, and depending upon how the programs have done, and whether or not you use rate design, the energy savings you see from CDM can free up energy for export sales during some of the higher priced hours in the winter. Most of the export market prices are higher during winter hours, and generally higher during peak winter hours rather than off-peak winter hours. So that's why CDM and demand response become particularly important as you move into an era where you have plenty of energy, but you have some concerns about capacity.

GREENE, Q.C.:

Q. And could you just show your findings?

MR. FAGAN:

A. Sure. This slide just shows that the peak savings that we find stem from both conservation demand management, as

conventionally known in the Province, and also from demand response, and this would be demand response separate from the interruptible curtailment capacity that currently exists in the Province, and then a significant portion of this is potentially available from the effects of heat pumps displacing or supplementing the use of electric resistance heating. As we show on later slides, the heat pump technologically is a superior way of getting heat from use of electricity.

GREENE, Q.C.:

Q. And of course, these – if you do focus on CDM and demand management response, these types of programs add additional cost for the customer and for the utilities. Did you consider costs in your analysis?

MR. FAGAN:

A. We did. Essentially on the island, because of the capacity value associated with peak shaving, that peak shaving coming from either DR or from conventional CDM, the programs tend to be fairly cost effective with a benefit cost ratio from the utility's

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perspective of on the order of 3.0.

The core inputs into this computation is what is the value of export sales that get freed up from CDM and what is the value of capacity if you peak shave on the island. The costs shown here, basically are amortized CDM program costs based on basic rubrics for the cost of more aggressive CGM programs. There's sort of a wide range on how you could actually implement more aggressive CDM. So the costs that are seen here could vary. You could certainly – you would want to maximum participating customer contributions to any CDM measures so these costs could be lower.

Alternatively, you can use CDM program design as a way to address the potential inequities that can occur through folks who are less able to have the capital to make improvements in residences or commercial businesses for CDM. But we generally find that because of this capacity value, the CDM and the demand response are particularly important and particularly economically valuable.

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GREENE, Q.C.:
Q. So, we've just reviewed at a high level the areas that you reviewed for the Board and now I'd like you, at that same high level, to summarize your findings in terms of the reference questions that you did some analysis on.
MR. FAGAN:
A. Sure. In short, increasing load through electrification, improving energy efficiency and using demand response to reduce peak and allow for increased export sales leads to the best possible outcomes for customers.
(9:30 a.m.)
It allows for the sale of the remaining Muskrat Falls surplus to external markets and the CDM effect helps to prevent a need for future capacity expansion costs.
We model a lot of different scenarios to try to tease out differential effects between the different combinations of electrification, CDM and rate design effects and essentially, we find that some combination of those three things, aggressively pursuing electrification, using

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CDM to peak shave and at the same time using rate design to provide incentives for consumption, preferably during off-peak periods of time, results in the best customer outcomes. What we clearly show is that there more than enough surplus available from Muskrat Falls to support these electrification needs.
I will note that in all of our analysis we assume the LIL is in service and we assume the LIL is providing energy and capacity of the LIL. To the extent that that would not be the case then you begin to perturb the findings that we've seen, although the capacity value would become even more important under any situation such as that.
GREENE, Q.C.:
Q. You've already indicated earlier in your presentation that the impact on rates overall with the most optimistic of your scenarios of electrification and CDM would not help with the rate mitigation problem. Is it correct that by 2030 the most that this would produce would be about a cent a

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kilowatt hour off the domestic rate? Is that generally what your analysis showed?
MR. FAGAN:
A. That's correct. The rate impacts themselves are significant, but they're not large.
GREENE, Q.C.:
Q. But overall, in terms of the appropriate use of energy and maximization of the resource, this is what you believe is the path forward for us here in Newfoundland?
MR. FAGAN:
A. Yes, absolutely.
GREENE, Q.C.:
Q. So, now we're going to look at a little bit more detail about what work you did to support those overall findings, and the first one we look at would be – and you've already mentioned that you model scenarios. Can you describe generally what you did and why you did it?
MR. FAGAN:
A. Yes. We wanted to model the interactive effect of rate design, increase CDM and electrification. The patterns of consumption associated with electrification

are different from the patterns of energy savings associated with CDM and both those patterns, in addition to underlying existing load patterns, can be shaped by rate design. So, in order to economically capture the variant patterns of consumption in export sales, we used a model that looked at things on an hourly level and then multiple scenarios just allowed us to mix and match different levels of rate design and different levels of electrification or CDM.

I mean, essentially there's infinite permeations of scenarios that we could have modelled and we had to try to narrow that down. We still ended up doing scenario analysis on roughly 38 different combinations, which is quite a lot to try to discern the differences.

GREENE, Q.C.:
Q. And if we could go to your next slide. This is – this slide illustrates the results of what we chose as the key illustrative scenarios that you ran. So, could you please explain what this table shows?
MR. FAGAN:

A. Sure. The results for all the scenarios are contained in the report. We do have listings of the effect across all 30 some odd scenarios. But essentially, we just chose a handful of scenarios to show the general pattern for CDM, for electrification and for the effect of rate design, time of use rates or the use of electric vehicle smart chargers. And what this shows, this presents five different metrics. One is just the change in utility revenues. Essentially utility revenues will increase with electrification and they'll decrease with CDM.
GREENE, Q.C.:
Q. And this – and excuse me, this is the change from your base case reference?
MR. FAGAN:
A. Yes.
GREENE, Q.C.:
Q. It's always in a comparison to what your reference case is?
MR. FAGAN:
A. Yes, that's correct. All of this is a change from the reference case. So, for

example, if the rates are – if the rates end up being set at, for example, 17 cents in 2020, the effect of a high electrification scenario would be to reduce the rate by on the order of eight-tenths of a cent per kilowatt hour and that's shown in this second row, the second set of columns.

Conversely, under a high CDM only scenario where you don't do any electrification other than the small amounts that are in the base case, you would see increases in rates on the order of 1.4 cents per kilowatt hour by 2030.

But what's coupled with that rate increase, as shown in the last two columns of this table, is generally a reduction in total energy expenditures and a reduction in the average energy expenditures on an average customer basis. And that's what this shows.

So, the last two columns capture the effect of reduced consumption and the effect of increased consumption but oil savings. Whereas the first column captures the effect of changing export sales and also changing

internal sales associated with the level of CDM or electrification that's used.
GREENE, Q.C.:
Q. And when you looked at the average energy expenditures, that's for all customers? Is that correct?
MR. FAGAN:
A. That's correct. This does not reflect, and as we note in the report and as we noted in the summary slides in this presentation, this does not affect – sorry. This does not reflect the distribution of these effects across rate classes or across sectors. Depending upon what sort of cost allocation is used from Muskrat Falls, for example, depending on the specifics of rate design approaches, depending upon how Governmental policies are implemented. All of those things can affect essentially the distribution of the benefits and the costs and to try to guess at exactly what that would look like at this point in time would be premature. We wanted to primarily answer the reference questions on the whole to get an indication of what makes the most sense,

increasing export sales, increasing domestic load and get a rough idea of what that quantitative effect would look like.
GREENE, Q.C.:
Q. So, if we could take just Scenario 12A where we see the average rate mitigation by 2030, it's there in red, which is just over a cent a kilowatt hour. That would show what we just talked about. Is that correct that if there is increased electrification, the Delta Utility revenues increase in 2025, 2030, and the average rate, cents a kilowatt hour, would go down? Is that correct?
MR. FAGAN:
A. Yes.
GREENE, Q.C.:
Q. That's how we are to read that table?
MR. FAGAN:
A. Yes, that's correct.
GREENE, Q.C.:
Q. Okay. So, if we can go to the next table?
MR. FAGAN:
A. Yes. This table essentially presents the components of the change in utility revenues that we saw on the prior table and it

indicates that the effect on revenues comes from not just the increasing revenues from electrification or the decrease in revenues if there's improved energy efficiency, but it also comes from the change in export revenues that would be seen and it also comes from whatever costs might be incurred to implement the CDM or to implement the electrification policies and it also takes into account the change in exposure to capacity costs that the Province would see.
So, for example, if we look at that same 12A, scenario 12A, the export revenues actually decline in scenarios where you have a lot more electrification because you're using the energy internally as opposed to exporting it. But the internal revenues increase significantly. There is a cost associated with those electrification policies, although in our accounting, we do not include the $5,000 per vehicle Federal rebate, for example. We do include the cost associated with heat pump incentives and electric vehicle charging stations that would be required. We also note that for

that scenario, there's a net increase in peak load. So, you do have exposure to the need for additional capacity costs and that's as you can see in the 20 – both 2025 and 2030.
So, essentially, this table breaks down the components to get to the net mitigation effects of the change in utility revenues that you see.
GREENE, Q.C.:
Q. If we could turn now to the more detail with respect to your work for the load forecast. Did you consider the impact on the forecast load of a significant increase in price?
MR. FAGAN:
A. Yes, we did. It's a tricky matter. With the projected rate increase that the Province is looking at, it's very difficult to use the traditional econometric estimating techniques, which basically look back and see how consumption has changed as prices have changed. But all of that occurs within a particular band width of price increase and the band width of price increase we're talking about now renders

that method a lot less effective and a lot less certain.
So, essentially, you can think about well, what options are in front of people and the options that are in front of people are switching from electricity or changing behaviours or changing technologies to use less electricity. And those types of responses are reflected in Hydro's forecast, what they call their low rate forecast, which contains a particular price elasticity that's essentially a relatively higher price elasticity than you might see if you just looked at conventional econometric estimating techniques.
So, based primarily on that and it – based on that, the Hydro's forecast is not an unreasonable forecast. We do think that they were a little bit – that they estimated a little bit high in some of those out years. Newfoundland Power, for example, estimated just a little bit lower. So, as you'll see in the subsequent slide – I'm just going to jump two slides up. As you'll see in this slide, for example, the dotted

line represents Hydro's forecast and you'll see that for the first five years, our base forecast is essentially the same as Hydro's forecast, but we do think that the trend that has been seen in the Newfoundland Power service territory is more predictive of what might occur in the latter portion of the period. So, we essentially see a flat to slightly declining energy forecast trajectory.

We did also look at some other trajectories in addition to our scenarios. For example, an extreme load trajectory, representing a price elasticity twice as high as what Hydro used in its low rate case, would show a decline by an additional 1500 or so gigawatt hours by 2030, which would be a fairly steep and significant decline.

But what this graph also shows is that under aggressive levels of CDM, the decline can also be fairly sizeable. So, to some extent, declines coming from price response are – they're not that different from declines coming from CDM. The CDM is the

mechanism that people will take to reduce their exposure to bills essentially.

Just to back up, this just reflects our underlying base forecast that we saw on that slide and it is broken down by the components, Newfoundland Power and rural and the Industrial sales. So, you can see what the actual total requirements look like.

Likewise for peak load, we essentially apply the same principles. You know, we see a peak load on the island that's similar to Hydro's forecast of peak load out 'til about the middle part of this coming decade. But when we see price response pressures to indicate that the peak will not grow quite as fast as Hydro forecasted them to grow out to 2030 in their low rate forecast case.

GREENE, Q.C.:

Q. So, as an indication of the impact that the significant price might have on customers if there is no rate mitigation, you model the extreme low load? Is that correct?

MR. FAGAN:

A. That's correct. And what you see with extreme low load, I mean, the net effect of

extreme low load would be that rates would have to go higher, but that bills would actually likely go down because that's what's happening. The consumption change is dramatic or more dramatic than it otherwise is. What comes with that extreme low load scenario is an increase in export sales to make up part of the revenue, but you do still have – but you will see a greater rate increase if that extreme low load scenario were to come to pass.

GREENE, Q.C.:

Q. So, if we go to slide 25, please. Here you showed a typical winter day peak and why is that important?

MR. FAGAN:

A. This is just important to point out that there's two periods of the day when the island sees its peak, in the morning and in the evenings, and there's not much of a difference between what those levels might be at the beginning of the decade and the end of the decade, based on our reference forecast. But primarily, this is just to point out that there is room for selling

additional export sales or internally to electrification load during the periods of the day that are not peak, overnight and midday essentially.

(9:45 a.m.)

So that just indicates that rate design needs to take this pattern explicitly into account when thinking about the policies that rate design – the ability for rate design to affect consumption. You want to save consumption during the peak periods and you want to promote consumption or export sales during the off-peak periods.

GREENE, Q.C.:

Q. Okay. The next slide, slide 26 is a busy slide. What's that supposed to tell us?

MR. FAGAN:

A. The main thing that this slide tells us, the report presents this slide plus similar slides for other scenarios and it just allows you to see the changing amounts of export sales during off-peak hours. It's basically a tally of the energy balance in the Province, and you'll note that the heavy thick line, that's at the top of the gray area, is the same pattern that we saw in the previous slide. That's the island load pattern. But that the total supply capacity available for export market sales is greater than those peak needs and what you'll see is that generally, they're able to sell a lot more, as much as they can, during the on-peak periods and sell less during the off-peak periods because the on-peak periods come with greater potential for revenue.

GREENE, Q.C.:
Q. So turning now to electrification, which is the most significant opportunity to increase revenue in your analysis. I want to look just at a little bit more detail and you already discussed how you looked at electrification for buildings and for in the transportation area. So, Dr. Hopkins, could you just outline a little bit more about how you did that analysis?

DR. HOPKINS:
A. Sure. In transportation, we looked at predominantly electric vehicles, both light and medium duty vehicles. You see that described as LDV and MDV. Medium duty

vehicles are things like delivery vehicles and buses. We also looked at the potential for further electrification of the port here in St. John's, although you'll see on the slides that that's a pretty minimal effect.

Building electrification, we looked at conversion of oil heating to electric heating for residential and for small and large commercial buildings. We've modelled that as conversion to heat pumps. Whereas, for institutional use, in particular Memorial University where the demand for very high heat is more likely, we modelled that as conversion to electric resistance.

We developed low and high electrification scenarios within each sector and those scenarios are designed to give a bookend sense of what the impacts on the electric system might be from lower or higher electrification.

GREENE, Q.C.:
Q. Okay. Those were the assumptions that you used for each of your scenarios and did you – when we go to slide 31, you also looked at costs that would be associated with

increasing electrification. Is that correct?

DR. HOPKINS:
A. That's correct. So, we looked at the costs that might come through various types of programs. For example, the electric vehicle incentive, although we assumed that that incentive would be covered by the Federal Government. We also looked at heat pump incentives and also the costs for installing charging stations.

GREENE, Q.C.:
Q. Okay. So, if we go to slide 32, we see the results of your analysis. Could you just explain them briefly, please?

DR. HOPKINS:
A. So, this is the high electrification scenario. The units are the total energy by year. Different sectors are able to electrify at different rates. So, you see Memorial University replacing one and then a second boiler as assumed and modelled by us that relatively early institutional buildings, again, moving relatively earlier. You get to see the relative scale of

residential, small and large commercial buildings, which are substantial but much smaller than the institutional load, partly because there's fewer square feet that we assumed would electrify and partly because those buildings are electrifying with heat pumps, which use a lot less electricity per amount of heat delivered.

Transportation sector has a somewhat different adoption shape, as you see, with the market developing much more towards the latter end of the period. This reflects the increasing availability of different electric vehicle models as they become more available and also reductions in cost in electric vehicles presuming to make adoption faster later in the period.

The next slide is the low scenario case. The shapes are similar, but the values are substantially lower, just for lower rate of adoption. Only one boiler at Memorial University and a much slower adoption of electric vehicles.

GREENE, Q.C.:
Q. Okay. So, if we could go to slide 34 where

you talk about the cost impacts. Could you please explain this slide?

DR. HOPKINS:

A. Sure. We looked at – you know, there's a question for electrification, will people actually do it, but does it make sense for customers to actually electrify their end uses. So, we looked at that in two different ways. One, this slide shows the aggregate. So, if you look at buildings, for example, the figure here, in aggregate across all of the buildings are the folks paying the energy bills in these buildings, are they paying less if they electrify than they would if they were using – heating using oil.

So, the two high cases shown here, for example, the high oil and high heat pump, shows the total spending on fuel, depending on which fuel those folks were using for their buildings and you see that the heat pump case is substantially lower than the oil case. A general sense that in aggregate, consumers in the Province would be saving money by switching from oil to

heat pumps.

GREENE, Q.C.:

Q. Okay.

DR. HOPKINS:

A. The other two that – the other way that we looked at this, shown here and on the next slide. This is for electric vehicles and the following one for heat pumps, looks at the individual customer economics. So, if you assume, for example, in the electric vehicle that a EV owner finances a new electric vehicle over five years and depending on whether gasoline is higher forecast or lower forecast prices, based on Canadian federal forecast data, generally speaking that folks who would get an EV would pay a little bit more, negative savings, increase in cost, while they're paying off the vehicle. But then for the balance of the life of the vehicle, they would see substantial savings from charging their vehicle with electricity rather than driving on gasoline. It's obviously more cost effective to drive an electrical vehicle if the price of gasoline is higher

and the rate design, which Ms. Whited will discuss later, does make some effect from the electric vehicle owner's perspective. A more favourable rate is available to them in terms of time of use or some sort of incentive rate, the more favourable the switch is.

GREENE, Q.C.:

Q. And you also looked at the impact for heat pumps, is that correct?

DR. HOPKINS:

A. That's correct. So, this is the same calculation, but for a single home heating with a heat pump using—again financing over five years, using Newfoundland Power's existing loan product. If oil prices are high, then the oil savings relative to electric basically pays for the heat pump over the course of the first five years and then it's all savings from there on out. So, you could see that this, if oil prices are high, it would be quite economical for a household to switch to using heat pumps. If oil prices are lower, it's a little bit more break-even where there's some additional

costs while you're paying off the system and some savings later, but it's a little bit closer to 50/50.

GREENE, Q.C.:

Q. Moving now to CDM and Demand Response, can you briefly describe how you did that analysis and what it showed?

DR. HOPKINS:

A. Yes. So, we were interested, as Mr. Fagan described, predominately in the savings that could come from lower peak load and avoided capacity costs, but many kinds of CDM measures are also result, of course, in energy savings. So, we looked at a base case, a low case and a high case. The base case is basically a continuation of current levels of programs, minimal adoption of heat pumps and the savings that embedded essentially in the elasticity response that Mr. Fagan described before. And then, the low and high cases reflect incremental additional CDM and heat pump installation. We did, also did a low and a high case for demand response. We looked at that from and end-use model, so building up from potential savings and adoption rates in heating, lighting, hot water, refrigeration, et cetera, and amortized the costs of the resulting CDM Programs over seven years as is the current practice here and calculated out the benefit cost values that Mr. Fagan described already in the summary.

GREENE, Q.C.:

Q. So, if we go to slide 39, that just outlines the assumptions that you used for adoption rates for your various scenarios, is that correct?

DR. HOPKINS:

A. That's correct, yeah. The adoption rates are generally higher in the residential sector as they have been historically and higher in Newfoundland than in Labrador. I'll just mention that this lower figure here is the same one that was corrected in the report.

GREENE, Q.C.:

Q. Right.

DR. HOPKINS:

A. The figure here is—that chart corresponds to the commercial case rather than to the

residential case.

GREENE, Q.C.:

Q. Okay. On slide 40, you then have a slide that shows a heat pump performance and potential savings. Is that correct?

DR. HOPKINS:

A. Yes, that's correct. So, a large fraction of the potential CDM savings in the province have to do with the adoption of heat pumps, and the reason why heat pumps present such substantial savings with respect to electric resistance heat is illustrated in the figure here in which the—which is from real data of major performance of heat pumps in real homes in cold climates. The Y axis is the coefficient of performance, essentially the efficiency of the heat pump where one is a hundred percent efficient or equivalent to electric resistance. And you can see that, you know, at freezing, the coefficient performance is well over two and a half. It's even over one and a half down below minus 20. So, there is substantial potential savings even on the coldest days from the adoption of heat pumps. We did

discount the potential savings that could—that technical data would imply and assumed that folks would, in fact, fall back on electric resistance heat perhaps more than they need to. Then the technical data would imply in order to be conservative about just how much savings might be achievable. So, you can see the discount in the table at the bottom between the full savings and the average savings reflects that correction for a conservatism.

GREENE, Q.C.:

Q. Okay. And the next slide shows the summary of savings?

DR. HOPKINS:

A. Yes, so this is those three cases, the base case, low case and high case total amount of achieved savings. Base case continuing programs would save on the order of 400 gigawatt hours by 2030, whereas the low case adds about 130 gigawatt hours on top of that. And the high case is about 300 gigawatt hours above that and that's the sort of the classic CDM portfolio separate from the heat pumps. And heat pumps are

shown in the lower chart where the low-end base case assumptions for a CDM used a low penetration assumption for heat pumps, where heat pumps save, I mean, somewhat over 150 gigawatt hours by 2030. In the high case where if Newfoundland were to follow the trajectory of some European jurisdictions in which heat pumps have become essentially the default replacement for electric resistance heat, then you might save as many as 700 gigawatt hours by 2030.

GREENE, Q.C.:

Q. Turning now to a little more detail on the low forecast. On slide 43, previously we talked about the energy balance. Slide 43 shows us the capacity that would be available after, with muskrat Falls. That slide 43 excludes recall. And can you explain that recall is and why you chose to show the capacity without the use of recall?

MR. FAGAN:

A. Yes, Muskrat Falls is on the order of 800 megawatts. The recall block is on the order of 225 megawatts. So, there's a significant amount of capacity available in Labrador.

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Essentially, you need a sizable portion of Muskrat Falls across the link to meet the requirements on the Island on the peak winter days. And that's what this slide essentially shows, that on the order of 600 megawatts is required across the link from Muskrat Falls in order to meet the requirements which leaves a few hundred megawatts available for export. Essentially the capacity for export, either by way of the Island path towards Nova Scotia and New England or by way of the Quebec path, depending upon the total of capacity that's flowing and the prices through those two paths. The second slide which represents including recall, essentially makes, if you make the presumption that the recall available after meeting Labrador requirements under a base forecast for Labrador, there is additional remaining capacity from the combination of recall and TwinCo assets in Labrador such that there's an additional hundred megawatts available for export. So, the net amount of export capacity available from the combination of

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recall capacity and Muskrat Falls is on the order of 300 megawatts. Whereas if you just look at Muskrat Falls, the amount is on the order of 200 megawatts. So, these slides are analogous to the energy slides that were presented earlier.

GREENE, Q.C.:
Q. Okay.
(10:00 a.m.)
MR. FAGAN:
A. The next two slides just present the total export volumes and the total export revenues associated with the surplus energy tied to all of the resources, both Muskrat Falls and the recall block. So, what this indicates is in our base case, you know, going out towards 2030, you see that the annual available export sales are on the order of 3.5 terawatt hours. And what you see at the bottom of the slide is in the high electrification case, there's 500 gigawatt hours less available because you're consuming that internal. And in this scenario is where you may have an extreme low load or the effect of just high

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aggressive levels of CDM. You see the exports sales volumes rising to 4.5, to an extreme level, as much as 5 terawatt hours in an extreme low load case. The revenues that are tied to those volumes essentially follow the same pattern as the volumes themselves. So, in the high electrification case, there's less revenue that you're receiving from export sales on the order of 140 million by the end of the decade, and conversely, in the high CDM case, for example, the export revenues in total rise to on the order 200 million dollars by the end of the decade.

GREENE, Q.C.:
Q. Okay. So, turning now to rate design, Ms. Whited, can you—why is it necessary to consider rate design when we're talking about electrification and CDM?
MS. WHITED:
A. So, there are several things that rates do. They can encourage customers to shift their consumption to certain hours of the day. And so, we wanted to look at rate design and how it can shape customer load in order to

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maximize export revenues to the highest value hours or specially to minimize peal demand, especially for new electrified loads. Rate design can also be used to encourage electrification. If you can provide a lower rate on the off-peak hours that encourages customers, for example, to adopt electric vehicles and charge them during the off-peak hours. So, we looked at several different designs and we made sure to base those on marginal costs so that the off-peak rates were always set above marginal cost. So, to go into a little bit more detail, we looked at rate design as a tool to do several different things: increase adoption of electric vehicles and other beneficial technologies that can easily be shifted; reduce the peak demand and then reap all the benefits in terms of avoided capacity costs; and again, to shift consumption on the Island to those hours that have lower export prices so that you can maximize export sales during the high-priced hours. We considered three different options primarily. One was the time-of-use rates with critical-peak pricing for all customers. We did a combination of time-of-use and critical-peak pricing because you get a lot more capacity benefit from critical-peak pricing than just time-of-use alone. So, it was our assumption that it would be much more cost effective to that. The second option that we considered was time-of-use rates, only for transportation, for electric vehicles and this can be done through the use of smart chargers. And it could avoid the need to do a full roll-out of advance metering infrastructure. And then, finally, we looked at some incentive rates, lower priced flat rates for electrical vehicles to encourage the adoption of those technologies. The charts on this slide show some stylized examples of time-of-use rates and critical-peak pricing. And what happens is that the critical-peak pricing actually gets layered on top of the time-of-use rate. The time-of-use rate that we used was a two-period-time-of-use-rate model with the peak hours between 6:00 a.m. and 11:00 a.m. and then again from 4:00 p.m.

to 9:00 p.m. The critical-peak-pricing rate, that would only be called a few times per year and it would have a much higher price during those hours. So, moving on to slide 51, we looked at the effects of time-of-use pricing on electric vehicles in other jurisdictions. In particular, we looked at this example from Detroit Edison as to how electric vehicles respond to time-of-use rates. And because electric vehicles are a large load and they can be relatively easily programed to automatically charge off-peak hours, and most driving actually does not occur during off-peak hours, it's a fairly easy load to shift and it has quite a large impact. So, this slide here just shows the flat rate in the light blue. A lot of people on a flat rate have no incentive to charge off-peak, so they simply plug in when they get home from work. If you implement a time-of-use rate, then that's the darker blue line. You can see there that most of the charging starts to occur after the off-peak rates come into play late at night, so 11:00 p.m. and throughout the middle of the

night. So, that helps you avoid charging during the on-peak hours and so it gives you a capacity benefit. So, what we have found from our rate design analysis was that time-of-use rates for electric vehicles make a lot of sense since you can shift a lot of load fairly easily and you can also implement time-of-use rates without doing full advanced metering infrastructure. You can use those smart chargers to roll out the time-of-use rates for EVs at a lot lower cost. This can also help incentivise transportation electrification, so helping to get to a higher electrification scenario. The time-of-use rates, plus critical-peak pricing with advanced-metering infrastructure has a reasonably positive impact, but we recommend doing a little bit more analysis to dig into the actual cost of that advanced-metering infrastructure. We assumed a 300-dollar-per-meter all-in cost based on recent experience across the Canadian Provinces and a little bit in the United States. That could be tested by issuing an RFP and getting more accurate

pricing. And then, looking at how customer load actually would respond in the province through doing some pilots. We looked at examples from Quebec and from Ontario and from the Northwest United States to estimate how customers might respond under time-of-use rates with critical-peak pricing, but there's been very little overall analysis in winter-peaking territories. So, it would be very advantageous to gather some data on the ground here in Newfoundland just to verify those assumptions.

GREENE, Q.C.:

Q. So, just to summarize on rate design, I understand that you did not come up with specific rates that you are recommending, but your analysis was more in terms of directional as opposed to a specific rate design. Is that correct?

MS. WHITED:

A. That's correct. We did test some specific rates just to understand what the impact would be on customers who were not participating in those, for example, EV time-of-use rates, and we did present those

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results in the report, but overall the results were based on assumptions regarding shifting of load from overall results in other jurisdictions, not on specific rates.

GREENE, Q.C.:

Q. Okay. Turning now to your overall observations from the work that you did. Mr. Fagan, what are the take-aways that we should take from your analysis?

MR. FAGAN:

A. I think the points listed on this slide have generally been covered in the presentation this morning, but at the highest level, policy supported electrification and enhanced CDM including the main response makes the most sense for customer outcomes. Electrification clearly has the highest mitigation value because of its increasing load to contribute to paying for fixed costs. The CDM is critically important because of its ability to help avoid future expenditures in capacity needs, and at the same time, it does allow increased levels of export sales and it helps to reduce bills at individual facility levels because of

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reduced consumption. As Melissa had indicated, rate design guided by the high-level analysis we show here can lead to the most efficient price signalling. The analysis we did captures that, in large part, but by capturing what the effective export sales look like when you have different levels of rate design and you shift the buckets of consumption internally to allow for greater levels of the export sales. We do note existing levels of industrial curtailment and potentially increased levels of that for demand response is critically important. That's a winter-peak capacity or peak-load shaving measure that doesn't necessarily involve a reduction in energy consumption and that's particularly important given the concerns about capacity needs in the future. You know, we note that it is better to do electrification as opposed to just maximize the exports sales, but at the same time, there's significant value in increasing those export sales. Essentially, the peak-shaving benefit of CDM helps to pay for most

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of it and then you also are able to sell more energy externally when you've implemented the CDM. So, while electrification is best, I'm not trying to minimize the importance of maximizing the export sales. As Melissa indicated, the time-of-use rates using smart charging for electric vehicles seems to make the most sense initially, but a little bit more careful analysis, you know, could reveal that broader use of AMI could make sense for the province. And then, lastly, but certainly not least, the government—federal and provincial policies have a significant effect on reducing the costs for energy efficiency and for electrification.

GREENE, Q.C.:

Q. If your findings are generally accepted, what would you recommend be the next steps to do further analysis?

MR. FAGAN:

A. Well, essentially as you would expect, based on the information and we've provided, the specific policies around electrification would need to be developed. Certainly, the

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form of incentives that might be used for equipment such as heat pumps would be important. I mean, for example, a policy discussion could revolve around how much of an incentive are you providing for heat pumps and are there minimum standards for those heap pumps that you're looking at? Do you couple provision of heat-pump rebates with, you know, a requirement to, you know, to try to improve building shelves at the same time? EV charges. Figuring out where and how many. We have a general sense of the total number of charges you would need, but exactly where they end up going in, and as I note below, the rate structures that would apply to those would be important. So, developing the CDM Programs themselves, what we have seen is that the enchantment of CDM Programs would be significantly—it's a significant bump up in your CDM activity is what we would be recommending. The development of those programs, it's full of a lot of detail. Essentially CDM Programs in part can help to address inequities that otherwise arise. You know, in a large part, the CDM Programs exist because of the market barriers that in place for people doing energy efficiency on their own. Otherwise all of this stuff would just be done. So, you know, in a way, you look carefully at how those programs can help to transform the market, and at the same time provide, in particular for customers who have less access to capital, addressing inequities that might otherwise—that have already begun to show up because most likely the heat pump installations that have already occurred are not occurring at the level of the lowest income customers, for example, in the province. And then, certainly looking carefully at rate design approaches is going to continue to make a lot of sense. Certainly, an initial form of TOU pricing for EV load is sort of the easiest rate design policy to implement on a quicker timeframe. And then, continuing to give careful attention to the monies that are available federally and the provincial policies that support electrification and increase energy efficiency would be

critically important. So, those are the four broad groupings of next steps that we see.

GREENE, Q.C.:
Q. Okay. Thank you, Panel. That concludes my questions, Chair.
CHAIR:
Q. Thank you, Ms. Greene. Mr. Young?
YOUNG, Q.C.:
Q. Thank you, Madam Chair. Good morning, Panel. My name is Jeff Young and I'm in-house counsel for Newfoundland and Labrador Hydro. Thank you very much for your report. I think you'll probably agree with me that there's a lot of information in there, but more to the point perhaps is you've identified a number of areas where we need still more information. Would you agree with that?
(10:15 a.m.)
MR. FAGAN:
A. Sure, of course. The reference questions bounded what it was that we were doing.
YOUNG, Q.C.:
Q. Right. And I'd like to explore three areas

today where I think, as we work through this over the next, certainly the next decade, the area that you've looked at more closely, we're going to need to understand better. Those three, electric vehicles, the dynamics around the heat pump phenomenon that we're seeing and how important that's going to be, and also some rate design implications of CDM. If I could start with electric vehicles, Ms. Sheppard, if you could perhaps turn to page 45 of your September 30 report? And there's a table there, Table 14. And what I see there is the amount of stock in the low scenario and the high scenario that you expect to occur for electric vehicles by 2030 and there's a fair bit of variability there, one and a half percent and seven and a half percent. And I wonder if I can next take you to page 41? And there's a footnote at the bottom of the page 43, and if you can just scroll up, just a little, so we can see where the reference is through the footnote? Thank you. It says, "Synapse use Newfoundland's historical pre-29 electrical vehicle adoption rate to develop the early

portion of the technology curve." The footnote is to an article which is interestingly called, "Looking For a Place to Plug In". The reference in the article, the article is about 18 months old, and it's about the number of electric vehicles in the Province at the time and this was your starting point, correct? I note that in the article it said there's roughly 500 hybrid vehicles and 122 full electric vehicles 18 months ago. Infancy, I would suggest to you. We've got a long way to go even to get to your low-case factor of 10, in fact.
MR. HOPKINS:
A. Yes, that's true, the market is very much in its early stages here and that's what the low case is, you know, for Newfoundland to lag five years behind the Canadian Federal targets for adoption of EVs.
YOUNG, Q.C.:
Q. Right, and it occurs to us that there might be a big of a "chicken and egg" question here. If you have no chargers, you will have no electric cars. If you had no electric cars, you'll have no chargers. You

said it just a moment ago that you have an idea as to how many electric chargers we might need to have installed, but you haven't really looked into exactly where they would be. What's your sense of that? What's the numbers?

DR. HOPKINS:

A. If you could go to page 53 of the report, Table 15, the number of chargers are shown here on this chart. So there's level 1 chargers and fast chargers and we see that they have relatively low case adoption for the province would need relatively fewer chargers, but to avoid setting barriers for the high case, you would need substantially more chargers. The other fast chargers might be, you know, stretching here, from here west, you know, it's a stretch across the island, for example; whereas, the level two chargers might be more scattered around in workplaces, retail establishments, et cetera.

YOUNG, Q.C.:

Q. And as I mentioned, we're kind of late coming to the table here, so I imagine

there's a fair bit of research we can look to or at least just observations we can look to from other jurisdictions as to their experiences in this regard.

DR. HOPKINS:

A. Yeah, a number of places that have higher EV adoption in Newfoundland and, you know, including much more advanced markets and the models that we used to develop these numbers are calibrated to what has been developed in other places and to transportation modelling in other places. It has tended to happen in the US earliest where states that are actively advancing electric vehicle adoption have pressed to remove this barrier quite aggressively. There are a number of states that have as many charges already as you might need to have even ten times as many vehicles as they have on the roads. One of the characteristics of EVs is that many folks are able to charge them at home and so you don't need nearly as many electric vehicle charging stations as you would need gasoline fueling stations, but it's getting exactly to that "chicken and egg" question

you mentioned, it is generally thought that seeing electric vehicle charging stations around and knowing that the chargers are available and that there's one near your work or there's one near where you shop is an important psychological effect to get folks to be willing to accept the idea that they're going to be able to drive their EV.

YOUNG, Q.C.:

Q. I wonder if we can pull up slide 35 from this morning's presentation? Thank you. The third bullet there, it says, "Electric grate design or incentive rates have moderate impact on customer economics." I'm going to make an assumption and ask you to respond to it, that the economic advantage of having an electric vehicle verses other fuel sources is sufficient that you don't need to incent it too much to happen, so the time of use considerations you're bringing to the table are really about shaping the load to avoid the peak, is that right?

DR. HOPKINS:

A. I would say there's two effects, definitely the shaping the load piece is essential to

get maximal system benefit, but also getting to the psychological piece, even if the effects on rural customer economics are relatively minor, the simple existence of a rate targeted towards electric vehicles that can be marketed as such may, implies a certain level of acceptiveness and blessing for electric vehicles, that the utility supports them, that the policy is in support of them, et cetera, which may further encourage drivers to consider electric vehicles. It is cost effective today in many places for electric vehicles to be the vehicle choice and yet, they are only a small portion of the market, so pure cost effectiveness may not be enough and so sending other kinds of signals, whether it's through infrastructure, as we just talked about, or through rate structures that are particularly marketed and beneficial towards electric vehicles could be pieces of an overall package for encouraging electrification.

YOUNG, Q.C.:

Q. I accept the notion, so you're saying that if customers see it on their bill or information from the utility that there's a time infused rate that's tailor made for electric service, that puts the idea in their heads. Have you observed that as a trend, though, when it's been introduced as causing some sort of an uptake in electric vehicles or can you take that out of the other noise of what's happening in the marketplace.

DR. HOPKINS
A. I might ask Ms. Whited who has looked at electric vehicle rates in California to answer that one.

MS. WHITED:
A. I don't think that we've been able to tease that out, but it is, you know, California has taken approach that they want to ensure that rates are available that make electric vehicle fueling as cost effective or the same costs are lower relative to fueling with gasoline and so, for that reason, you know, they have really pursued lower rates for electric vehicles than you might otherwise see.

YOUNG, Q.C.:
Q. Thank you. I just make that observation because I can see how nicely it works to avoid suppertime peak, as you've just described a few minutes ago. So, if for no other reason, we do it for that reason, I think, or certainly look at it for that reason.

MS. WHITED:
A. I could add one additional point is that the cost effectiveness of electric vehicles depends a lot on the gasoline price, you know, what the alternative would be, and we know that gasoline prices are volatile, so providing an electric vehicle rate or a time of use rate when you know that you can charge during off-peak hours gives you some insulation from that volatility of gasoline prices so that you're more assured of actually being able to see those savings, regardless of what the gasoline price is.

YOUNG, Q.C.:
Q. I'm just thinking about the way people line up at the pumps here when gas is supposed to go up, a response to a pricing was a real

thing here for fueling a vehicle, however it occurs. I want to turn now to heat pumps, I have some questions about that. Can we turn to page 65 of the report please? And this chart is in your report; it's also in your presentation, and you've discussed it already to some extent and the point you raised is—a couple of points, I suppose, and I'll just make an opening comment, in this particular place you sit today, St. John's, it's a relatively temperate Canadian city, not without our cold snaps from time to time. Five years ago we had a doozy which you can Google or you can talk to Liberty about it, they'll tell you, but what I see here is, as you've remarked, around the zero mark and even down to minus 10, fairly flat, the coefficient, the advantage of the technology over resistance heat is quite solid, it's two and a half times.

DR. HOPKINS:
A. Right.

YOUNG, Q.C.:
Q. And it trends down to one and a half times at minus—it looks like minus 23. I'm just

curious, is it linear if you extend it out further and went down, just say if you looked at a number, like minus 27 or something, just curious.

DR. HOPKINS:
A. I haven't seen actual measured data. If it goes down that far, some heat pumps have minimal temperatures at which they operate. One of the other things that is going on is that the capacity of a heat pump to the amount of heat that it can deliver tends to also be falling as the temperature goes down and so, that's part of the reason you would imagine that folks would keep their electric resistance heaters, if they have them and perhaps also the oil heat in al electrification context and to be able to make sure that they simply can deliver it. The amount of heat that the building requires as it goes up as it gets colder, the amount that a heat pump system, which an air source heat pump system can provide is falling as it gets colder and there's some cost overplay when you need some sort of other heat in the building. Now, it may be

that that cost over point is only experienced for two or three hours and if your heating system can't quite keep up for two or three hours, so the temperature in your space falls by a degree or two and then you recover and that's fine, but generally speaking there's a lot of different kinds of things pulling in different directions at the low end of that range. My understanding is the so-called design temperature here in St. John's is in the range of minus 20 or so and that's a temperature at which the heat pumps are still performing quite well.

YOUNG, Q.C.:

Q. I would suggest to you it's more true of St. John's than other parts of the island and certainly the Province as your research in Labrador shows.

DR. HOPKINS:

A. Yes, that's true.

YOUNG, Q.C.:

Q. I wonder if we could see page 66, please? And there's a figure 28 on that page. So we see a fairly healthy uptake here. This is, I believe this is Newfoundland Power's

customers and so by 2018, 18 percent of electric heat customers had heat pumps and the point you raised about the two different types of heating systems is what I want to understand a little bit better. As you've pointed out in your report, the vast majority and it's clear from this, the vast majority of heat pumps that people have installed here are the mini-split types, the ones that sort we see fairly commonly hung on the walls here in homes. At the bottom of the page there's a comment there, you say, I'm going to put words in your mouth, I know it's dangerous, last week someone got accused of treason for doing that, but you say essentially that to understand the effect of heat pumps you have to understand how they're used and I suggest to you that makes sense. I don't know if you've researched this particular—I'm going to give you anecdote that I know from several people, which I'm curious, I'll ask you to respond to, there are people who had oil furnaces and they installed heat pumps and then they said they had to get the house

rewired to some degree for the heat pump and they realized that the oil furnace would be there as a supplemental heat, really, because most of their heat was coming from the heat pump systems they put in, so they converted their hot water radiation, oil fired furnace, to electric fired or electric fueled hot water radiation as a supplemental system. So in that scenario you've done-- one of the things you are seeking to do, I suggest, you've electrified the customer, although this has already happened for these particular people, which will be a good thing for rate mitigation, but on the margin, they are not—when I say "on the margin", I mean at those very cold temperature days, their backup heat system, the conversation we had a moment ago, is not fossil fuel, it's electricity, it's resistant heat, so what I'm curious about and I don't think we know enough about this yet and need to learn more is how that works with the peak hour, you know, those few hours in the year when it's very cold and peak use is high. I'm going to suggest to

you and ask you respond to it because I know you've looked at this fairly closely, with respect to heat pumps and not driving the peak, would the kind of scenario I talked about just now, where people are moving away from oil so that they call electric customers first, with a heat pump, are you concerned about how you can manipulate the peak with that scenario?

(10:30 a.m.)

DR. HOPKINS:

A. The electrification heat pump adoption discussion is looking at that type of situation in particular and in our electrification high case we imagine the folks not keeping their oil systems so that the case that's comparable to what you've just described, including the lower average coefficient of performance that comes at that coldest times. We didn't model in particular those folks switching over entirely to electric resistance backup, I would say that one of the things that might come in program design, when it comes to that, is trying to get systems to be sized well and incorporated well into the other heating systems in their homes to mitigate those peak effects to the extent that makes sense, that could come in the form of incentives, rates, other things. That's getting into details further than we went in our analysis, but we did look at that electrification case and the potential peak impacts of folks not keeping their oil system at all.

MR. FAGAN:

A. And let me just supplement that, it is our understanding that Newfoundland Power is conducting load research studies. Those are critically important studies. I mean, for example, part of what those studies will do is help us determine to what extent is the anecdote that you described common or uncommon, but just getting a better handle on all of that gives us a better understanding of what type of peak reductions, for example, you could reasonable predict or model. So that type of analysis is important. Lack of that data doesn't reduce the overall effect of our

findings, the importance of these patters, but that will be critical to help shape the type of policies that you may want to have in place to help minimize instances where peak load increases. You know, we do model peak load increases associated with electrification from an oil heated, the oil heated buildings.

YOUNG, Q.C.:

Q. So just further to that, the tools you would use once we have this, and I'm thinking five or six years out now, would it be a critical peak pricing means of trying to address the peak or is there another means?

DR. HOPKINS:

A. I'll draw an example, so in the low electrification case we modelled a case in which folks were offered an additional incentive to keep their oil system and to have the systems be interacted, rather than necessarily to switch to resistance and in that case to actually have folks keep the system they have and use it when it's below a certain temperature. So for example, Hydro Quebec has a duel fuel rate, it's just

a standard rate offered that you can switch off of electricity when the temperature is below a certain level, they have an outside temperature sensor and whenever it's below, you know, minus ten or whatever, it switches over. So we modelled that kind of case in the low case, so I think there are a lot of different options with respect to the hardware that customer keep in their homes and whether it's an incentive structure or rate structure that would be intended to try to get the most system benefit, while also making economic sense for the customers.

MR. FAGAN:

A. And as a compliment to what Dr. Hopkins has talked about, we did model the critical peak pricing effect also which can have an effect on any peak use essentially, but certainly to the extent that that type of a rate structure was in place. That goes a long ways towards mitigating whatever the effects may be, regardless of the policies you have in place around electrification and incentives to retain oil.

YOUNG, Q.C.:

Q. Can we turn to page 125 of the report because I understand this one better, to some extent your answer addressed this, but the second bullet there on the page refers to the information from the Dunsky Report and it talks about the mini-split heat pump systems complementing but not replacing oil-heat systems as economic. So I'm just curious, perhaps you can discuss this because I'm curious what the customer would feel about that reference. Does the term "economic" in that sentence, does it refer to the overall or is that by a customer basis what makes sense?

DR. HOPKINS:

A. I guess the "economic" there is being credited to Dunsky and I don't remember exactly how they were framing that.

YOUNG, Q.C.:

Q. Fair enough, but the point you raised about, with the Quebec example a moment ago, is that one thing that possibly could be done is to make it economic for customers.

DR. HOPKINS:

A. Right, looking at the actual customer

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economics of, example homes where they are, you know, how systems might integrate well, you know, mini-split systems tend to be good complements to radiator based systems and so, being able to displace some large fraction of oil use for when times when it's, you know, cold but not as cold, or in the most commonly used portions of the home, for example, you might put a single head in a large open living space and you use that to heat the home most of the time, except when you have guests and you turn the heat on in the back of the house, so you know, whenever the other kind of situations might arise. Houses are all unique; everybody's house has its own characteristics, but I think this is getting into the details of the kind of program design that would be reasonable to do when you're thinking about trying to actually figure out how to make something like this happen in practice for customers.

YOUNG, Q.C.:

Q. Thank you. So what I gather from what you just said and what was said a little bit

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earlier is that you have a fairly delegate balance to make here, you're trying to electrify, you're trying to get perhaps more heat pumps in the system, but you are concerned about the peak because that drives capital costs. So it's the program design you referred to, I think and you can confirm that or otherwise, which rolls that out, if I can put it that way, to make sure that you don't drive the peak with the hard –

DR. HOPKINS:

A. I would say that's a fair characterization of the kind of balance that you're trying to strike and there's a number of different kinds of levers, whether you call them programs or call them rates or call the policies, that you might pull on to try to reach for some combination that makes sense for the electric system, makes sense for family budgets, makes sense for the profits, makes sense for decarbonization, objectives that make—yeah, there's a lot of different things that might be pulling on the designs of those systems.

YOUNG, Q.C.:

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Q. Right, thank you. Move on now to, well I'm calling it CDM and rate design, I'd like to explore this a little further. I wonder if we could look at the chart on page 7? It's in your presentation also, but I'm more familiar with your report, page 7 of your report. It's Table 1 on page 7. This chart is full of information, this is an excellent summary chart. If some people, if they read nothing else and they read this, I think they'd glean all from it, but there still might be some other important information to understand here. And just so that we can understand it, if we took just the first row across, which is No. 6, the high CDM case which I understand was there as part of the research, it's not necessarily what you're proposing or suggesting, but just so we understand it what we see is a fairly high rate increase, well a cent and a half less, one point four cents from that scenario and we see a revenue drop and corresponding total energy's expenditures drop in the third last column there, correct?

DR. HOPKINS:

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A. That's right.

YOUNG, Q.C.:

Q. So what we're seeing there is a fairly high response to CDM which drives down the total energy which because the costs are fixed largely, not much from the incremental production cost, the rate has to go up to capture the difference, the unit rate.

MR. FAGAN:

A. That's correct, the rate goes up, overall consumption goes down, the level of export revenues shown on the complementing Table 2 goes up in this scenario and then that gives you the overall utility effects.

YOUNG, Q.C.:

Q. The other thing that happens is that in scenario is some customers, even though they're paying higher rates, you were explaining earlier they could have lower bills.

MR. FAGAN:

A. I'm sorry, could you repeat that?

YOUNG, Q.C.:

Q. Yes, I certainly can. I think you said earlier that some customers, even with higher rates if they were able to participate fully in the CDM, they might actually have lower overall bills.

MR. FAGAN:
A. Yes, that's exactly what this shows, the average customer. What this doesn't show is the distribution of bill effect across all the different customer types.

YOUNG, Q.C.:
Q. Right, and that's the point I want to explore a little bit because in this room all kinds of customers are represented, different classes and even within classes you'll get differences amongst customers. So the other one that I found very interesting and we talked about this already this morning, you've talked about it, is 12A which shows a rate decrease and also lower average costs.

MR. FAGAN:
A. Yes.

YOUNG, Q.C.:
Q. So my question is, it's a fairly simple one, when you're pursuing the rate design that might work best and the, I suppose the suite

of options you have, which is not just rate design, it's also electrification and things of that nature, some of which can be done through rate design, but other programs and incentives can occur, would you—and I don't know if your research has gone this far, would you look at using screening tests to decide which programs to use and I know you know more about this than I do, but it would be the rate impact tests, the RIM test or something of that nature, would that be then overlaid upon this analysis to come to what might be seen to be more fair, which is you wouldn't want a particular kind of customer to bear a lot of the burden and pay higher rates, perhaps and have higher bills, because they can't participate in the CDM.

MR. FAGAN:
A. Multiple parts to that question. You certainly can use screening tests. We would not recommend the rate impact measure test to be the primary screening test; we recommend a utility cost test and perhaps a total resource cost test to check that. The last part of your question, I mean, what

we're seeing in the high CDM case, for example, which highlights this because it doesn't look at electrification, is that rates do indeed go up, but the average bills do indeed go down because consumption is dropping significantly so, and what a more careful look at program design would do would begin to tease out what's fair. Who is going to see their consumption drop and why, and what can you do to ensure that all rate payers have access to the economic improvements so that the benefits associated with this average bill decrease can be distributed across as much of the customer base as is possible. Absent the CDM programs to the extent that you have a price response affect, those who don't have access to the CDM programs are going to see the higher rates and no means to mitigate their consumption, other than straight up customer behaviour turning the thermostat down, for example. But I think if it is a complex CDM program design task to look carefully at how the CDM programs can address the inequities that otherwise are going to occur. Now you

talked about 12A and you talked about 6, those are sort of the opposite ends of spectrum here. I mean, 12A excludes CDM effects and clearly shows net benefits. 6 excluded any electrification and shows on average net bill benefits, but rate increases.

YOUNG, Q.C.:
Q. Yes, that's right and I did indeed choose those two ends of the spectrum to show the point, yes.

MR. FAGAN:
A. Right, and I would just further leave you to look at the combinations because the combinations is all we recommend, that you need both, that clearly electrification is somewhat obvious, to the extent that you can electrify, you increase the kilowatt hours sold, but the critical importance of CDM comes in primarily on its capacity value, but at the same time it allows you to sell additional and it helps those customers who have no—it helps customers with their bills because it reduces there consumption and people pay the bills. They are exposed to

the rate, but ultimately what they're paying is the combination of the rate times the quantities and we're talking about significance just in quantity.

(10:45 a.m.)

YONG, Q.C.:

A. Accept that, but I guess the only question I have and this is, you know, the rate design choices and considerations for our future, are whether or not you have to somehow protect or certainly be aware of, be sensitive to the customers who can't easily participate in some CDM programs because of their circumstances, you know, I'll take what is not an uncommon demographic, in fact a growing demographic in this Province, is an aging couple, empty nesters living in a house without a lot of cashflow and not a lot of opportunities to pursue different kinds of fuel switching or CDM programs, things of that nature. I assume and as I said a minute ago, I know you three know a lot more about this than I do, but I assume that in other places there is some means of protecting or screening the programs to

ensure you don't have untoward effects on that sort of demographic?

MR. FAGAN:

A. Yes, you've basically set the table for the challenges in front of the Province for the CDM program design, but what's important technologically, even those dwellings there's technological potential to improve the energy efficiency of the consumption in that space.

YOUNG, Q.C.:

Q. Agreed. Thank you very much, those are all my questions, Madam Chair.

CHAIR:

Q. Thank you, Mr. Young. Mr. O'Brien, do you want to –

MR. O'BRIEN:

Q. Thank you, Madam Chair. Good morning folks, Liam O'Brien on behalf of Newfoundland Power. I don't have too many questions for you, some of them might just follow up on my friend, Mr. Young's questions. One of the ones in that regard was with respect to the transportation electrification. I did have a follow up question on that and you've

provided some additional information in response to Mr. Young's question. One of the questions I had was with respect to the direct current fast charging stations. There doesn't appear and I'm assuming you will agree with me at this point any sort of third party market for that in this Province and it seems to me that you would need government or utility intervention to get, to kick start those fast charging stations and that sort of thing, would you agree with me?

DR. HOPKINS:

A. I'm not as familiar with the specific market dynamics here, but generally speaking, yeah, jurisdictions across the US and in Canada have found the need to do some sort of, you know, priming the pump, getting yourself out of a catch twenty-two of charging infrastructure and –

MR. O'BRIEN:

Q. The "chicken and egg" we were kind of –

DR. HOPKINS:

A. The "chicken and egg", so some sort of—now whether that takes the form of, you know,

incentives, loan guarantees, other things that might bring third-party investment in or it takes the form of utility investment in some of the infrastructure or all of the infrastructure to support that charging, there's a range of different kind of options out there, but generally speaking some sort of thing that kicks you out of a state of low EVs and low EV charging into a, push towards a world where you might have high EVs and high amounts of charging.

MR. O'BRIEN:

Q. And would that be more beneficial than sort of looking at rates, incentive rates as a matter of kickstarting things or –

DR. HOPKINS:

A. I don't think, I always still think I would know a priori what's more or less beneficial. I think it's part of, you know, a number of things that would be part of an overall package approach.

MR. O'BRIEN:

Q. Okay.

Mr. Fagan:

A. You know, the federally V incentive just

coming into effect. There are other things that are going to be changing the market, different vehicles that are available. I think overall being flexible and nimble, having end goals in mind and bringing different tools to bear to try to pursue those goals makes a lot of sense to me.
MR. O'BRIEN:
Q. And have you seen that in any other jurisdictions, that kind of package where there's a rate sort of coupled with sort of investment at the same time sort of brought out as a package?
MS. WHITED:
A. Absolutely, we've seen that a lot throughout the northeast, as well as California. So, for example in Massachusetts some of the new programs by the utilities include investments in both infrastructure, as well as off-peak incentive rates for EV charging.
MR. O'BRIEN:
Q. All at the once coming out, at the one time?
MS. WHITED:
A. All at once, yes.
MR. O'BRIEN:

Q. And in terms of the incentive rates, just sort of looking for an idea as to how that works, is it just the time of day kind of rate or is there any other complement to that?
MS. WHITED:
A. Yeah, primarily it's for off-peak charging, so you provide some type of incentive for off-peak charging. Most of the time that's through separately metering the charging to ensure that customers are charging off peak, but in some small municipalities without advance metering infrastructure, sometimes they offer a flat incentive of, say, $15.00 per summer for customers agreeing and, you know, proving to the utility that they have set their timers to charge off peak.
MR. O'BRIEN:
Q. Okay, all right. And following up with my friend's questions on heat pumps, I did want to refer to a slide you actually never referred to in your presentation, slide 29. I wonder if we could bring that up? It's just follow up on one of Mr. Young's questions and you did provide a fair bit of

information here with respect to billing electrification assumptions, and it was with respect to the high scenario there where you assumed no buildings retained oil heat as backup for peak days. In this type of environment, is that something you'd realistically expect to happen, to have no backup for peak days?
DR. HOPKINS:
A. The purpose of that assumption was to sort of test the limits of high potential peak impact, not necessarily to say that this is, you know, we've generally said the high electrification case is more beneficial.
MR. O'BRIEN:
Q. Okay.
DR. HOPKINS:
A. This is one case where I might say combining some factors here of trying to aim, you know, trying to get a lot of electrification but managing the peak it would be more optimal. So, you know, getting that retention and coupling those systems together and the various ways that are discussed previously makes more sense to me

from a system standpoint and from a customer standpoint.
MR. O'BRIEN:
Q. Okay. I appreciate that. And in terms of savings from heat pump adoption and you've referenced, actually in your earlier, in your initial presentation there about an error on Table 76. I wonder if we could bring that up, Table 76 of the report? And, Mr. Fagan, you had referenced that in terms of being a response to a question from Newfoundland Power as a clarification from your report. So that was the annual heat pump electricity use of 29,613 kilowatt hours and you had indicated just for the record that that figure should have been 10,768, is that correct?
MR. FAGAN:
A. Yes, that's correct.
MR. O'BRIEN:
Q. And I just want to have you sort of walk me through how it's calculated. From what I can gather, it's calculated by applying the coefficient of performance for heat pump usage to that overall figure, is that right?

DR. HOPKINS:
A. So what 29,613 kilowatt hours corresponds to is the amount of heat to be delivered into the living space in the building and so given the seasonal average coefficient of performance you require substantially less kilowatt hours to deliver that much heat because you're simply moving the heat from outside to inside.
MR. O'BRIEN:
Q. So essentially you divide your 29,000 by your coefficient of performance, which I think was 2.75, is that right?
DR. HOPKINS:
A. 2.75.
MR. O'BRIEN:
Q. And you come down with your 10,000. So that sort of gives you an 18,000 and change kilowatt hour savings, is that right, is that how that works or –
DR. HOPKINS:
A. If the home were heated with electric resistance heat, it would in fact demand the 29,613 kilowatt hours so that the savings from going from resistance to heat pump is

that 18,000 or some difference.
MR. O'BRIEN:
Q. Yes, and that 29,000, where did you come up with that figure?
DR. HOPKINS:
A. So that's based on, I'm trying to remember back, but I think basically we looked at total oil use and total number of oil heated households to figure out how much oil those households are using on average, that corresponds to a certain amount of energy, as a efficiency of an oil system to deliver that heat into the space and so it's effectively equivalent to the oil use heat delivered into the space. How do I deliver just as much heat with electricity?
MR. O'BRIEN:
Q. Okay. And I'm going—and just in terms of comparison, I'm being told that from Newfoundland Power's records the average household would have 23,000 in total electric use and of that about 55 percent of that would actually be heat. So that figure, in comparison from electric use would be around 13,500 verses your 29,000,

would that make a big difference to your analysis in that scenario?
DR. HOPKINS:
A. I'd have to go back through and check all the math there, but yes, generally speaking if the amount of heat demanded in a household is a substantially less than the savings from the heat pump is also that much less.
MR. O'BRIEN:
Q. Okay, so would you have had that information from Newfoundland Power in terms of the average heat usage for an average household?
DR. HOPKINS:
A. I don't remember whether we had that particular piece, given that the analysis we were doing in this case was for oil heating homes –
MR. O'BRIEN:
Q. For oil, yeah
DR. HOPKINS:
A. - your average residence that heats with electricity is not necessarily the same as your average residence that heats with oil, and so we built from the oil data, rather

than from electric data.
MR. O'BRIEN:
Q. Okay, so the oil data would be different than someone moving from base heating to sort of a heat pump scenario?
DR. HOPKINS:
A. Right.
MR. O'BRIEN:
Q. And maybe this is a good time to take a break, Madam Chair?
CHAIR:
Q. Do you have any further questions?
MR. O'BRIEN:
Q. I have, I might have maybe five minutes of questions.
CHAIR:
Q. Okay, won't hold you to it, just want to make sure.
MR. O'BRIEN:
Q. Okay.
CHAIR:
Q. I just need to know who to go to, that's all.
MR. O'BRIEN:
Q. Okay.

(OFF RECORD – 10:58 A.M.)
(RECONVENED 11:31 A.M.)
CHAIR:
Q. Thank you. Back to you, Mr. O'Brien.
MR. O'BRIEN:
Q. Thank you, Madam Chair. Just one more question, folks, on this Table 76, the heat pump loan I guess that you've got indicated there, the five years, am I right in assuming then that your upfront cost assumes or I guess your analysis assumes that the upfront cost of the heat pump will be paid off over a five-year term, is that right?
DR. HOPKINS:
A. Right.
MR. O'BRIEN:
Q. Okay, so the initial savings you wouldn't see until the end of the five years, you'd see a jump in savings for customers.
DR. HOPKINS:
A. That figure on the slide shows that's five years of and then it jumps up –
MR. O'BRIEN:
Q. And just shows that increase on the slide.
DR. HOPKINS:

A. - and then it jumps up when you take off the system.
MR. O'BRIEN:
Q. Okay. Just one last area and that's with respect to the time of use and critical peak pricing rate design. Newfoundland Power's—I understand Newfoundland Power's load shape is relatively flat and when I say that, I understand it's over sort of, there's about 14 hours of the day where it's within 10 percent of peak, would that make an effect—would you see just a movement of peak then if you looked at rate design for time of use and critical—I guess for time of use design, would that change your analysis?
MS. WHITED:
A. It's definitely important to have the peak periods long enough so that you don't simply shift the peak to a different hour.
MR. O'BRIEN:
Q. Right, okay. So that may have an effect as to whether or not, I guess, defeats the purpose of the time of use of looking to shift peak if it's already kind of shifted, is that fair?

MS. WHITE:
A. It could if your peak hours or if your peak window is too short so that you simply shift the peak to a different hour. If you can shift it into enough of a trough, then you don't actually create a new peak, just at a different hour.
MR. O'BRIEN:
Q. Okay, so that's something for rate design to have a look at in terms of –
MS. WHITE:
A. Absolutely.
MR. O'BRIEN:
Q. And just one more question really with respect to time of use rates and critical peak pricing, did you consider that in terms of other demand responses, such as, I guess, curtailment and how that would work?
MS. WHITE:
A. Yes, so we assumed that demand response through, say, direct load control, would be an alternative to doing time of use rates with critical peak pricing. We expect that if you already have demand response programs to that effect in price, that there will be

much less load available to shift through critical peak pricing, so it's a bit of an "either/or" proposition.
MR. O'BRIEN:
Q. Okay. All right, those are all my questions, Madam Chair.
CHAIR:
Q. Thank you, Mr. O'Brien. Consumer Advocate?
MR. FITZGERALD:
Q. Thank you, Madam Chair. Good morning, panel. My name is Stephen Fitzgerald representing the Consumer Advocate. Just a couple of questions. An overall question at page 10, arises from page 10 of your September 3rd report, if you could go to that, and this is, the way it's articulated it's difficult, it's a difficult issue, of course, the way you articulate and say "revenue changes", I'm looking at the third bullet at page 10, "Revenue changes from CDM load reduction electrification. A critical tension running through our analysis from the perspective of the utility system is a net effect of increasing revenues through electrification while losing revenue due to

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increased conservation and efficiency."
This seems like the paradox that we're
struggling with, from a consumer's
perspective, in lay terms, is there another
way to express that or what exactly is the
critical tension? What are the consumers to
do, electrify or conserve?
MR. FAGAN:
A. The short answer is both, and I don't mean
that flippantly. Electrification replaces
oil end uses with more economic overall use
of electricity. CDM at the same time allows
you to most efficiently use the electricity
for the end uses that you need; and in
particular, it also helps during peak
periods of time to reduce the overall peak
load. So the overall aim would be for the
electrification increases in load to occur
more during off-peak hours than during on-
peak hours, and for the CDM improvements to
have a significant impact on peak load while
simultaneously there will be off-peak energy
savings associated with CDM and export sales
will also be increased for all energy
savings that arise from CDM. So the short

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answer is yes, both of those things should
occur; different mitigation effects arise
from each of them.
MR. FITZGERALD:
Q. Well which is so different effects but the
combination provides them most effect, is
that –
MR. FAGAN:
A. Yes.
MR. FITZGERALD:
Q. Okay, so but from the consumers—or are you
suggesting that the Provincial Government
policy should be electrification or is this
a message to consumers that they should take
steps now in the looming Muskrat Falls era
to electrify?
MR. FAGAN:
A. The message of our report to the Board and
to the government and to stakeholders, is
that the combination of both of those things
is important. The message to consumers,
individual consumers, is always use
electricity more efficiently if you can, and
in this case you can end up with a better
economic outcome for replacing oil end uses

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with electricity end uses in further areas
that we model for the transport sector and
for the heating sector.
MR. FITZGERALD:
Q. Okay. In your conclusions, I don't know if
this is fair to ask this or not, but do you
think that there may have been a bias
against oil in your promotion of
electrification?
MR. FAGAN:
A. Sorry, could you repeat that question.
MR. FITZGERALD:
Q. You know, are we comfortable, can we be
comfortable that in your presentation to the
Board that there was no inherent bias
against the oil industry, if you will, and
that the electrification solution that
you're advancing is actually the most
logical?
MR. FAGAN:
A. Oh yeah, that's straight up economics, this
just shows what's the least expensive way to
get the services that either oil provides
for transport or electricity, that either
oil provides for heating or electricity and

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then it's a straight up technical and
economic analysis comparing the two fuels.
MR. FITZGERALD:
Q. In your analysis and in your presentation
was there any consideration given to, you
know, the fact that Nalcor itself, I guess,
is partially an oil-based company, our
economy in Newfoundland has been somewhat
reliant on that industry in the recent past,
was there any consideration of this, you
mentioned the new money that's saved by not
burning oil, if you will, was there any sort
of macroeconomic view of the best interest
of the Province whether the electrification
could impact on the oil industry at all?
MR. FAGAN:
A. We did not do a macroeconomic analysis. A
macroeconomic analysis could look at that
and if we were to do that, at the same time
you would also want to look at the effect of
the electrification in the CDM for example,
and the macroeconomic effects that those
things would have, coupled with whatever
macroeconomic effects might occur from a
reduction in the use of oil.

MR. FITZGERALD:
Q. Thank you. Just to move to heat pumps briefly, when you looked at the economics of the heat pump recommendation, were there other alternatives and particularly I'm thinking about convection heating, would that be a type of heating that could be implemented as well in a general sense?
DR. HOPKINS:
A. I'm not sure I know what you mean by convection heating.
MR. FITZGERALD:
Q. Convection heating, it's not a mini-split, it's not a heat pump, it's resistance—if you're not familiar with that type of product, then I'll move on, but it's a resistant type of heating mechanism, but it's not full on baseboard heating, if you will. If you're not familiar with it, then we'll move on.
DR. HOPKINS:
A. I'm not familiar with it. Just in general terms the amount of heat that goes into the space is determined by, and the resulting electric demand, are going to be determined

roughly speaking on whether you're moving in the heat pump case or producing it through resistance and the exact mechanism by which the heat is distributed throughout the space should be a relatively minor effect relative to the question of where the heat is coming from.
MR. FITZGERALD:
Q. Okay, fair enough. The EV and—or the electric vehicles, was there any consideration to whether hybrid vehicles would be an alternative in the circumstance where if you go all electric and the system goes down, then you have no backup. I mean, is that a, would there be any sort of advantage to promoting hybrid vehicles as opposed to all electric?
DR. HOPKINS:
A. We've lumped them together, but actually the analysis is a fair split between hybrid plug-in vehicles and all electric vehicles.
MR. FITZGERALD:
Q. If I could take you now to page 100 of your September 3 report. This is Table 46 and 47, and 46, I think in a general sense,

records total export sales by way of gigawatt hours and 47 refers to it in monetary terms, correct?
MR. FAGAN:
A. That's correct.
MR. FITZGERALD:
Q. So the amounts that are expressed here in Table 46, total gigawatt hours, are these including or excluding the Nova Scotia obligations?
MR. FAGAN:
A. This excluded the Nova Scotia obligations associated with the block and the supplementary energy.
MR. FITZGERALD:
Q. Okay.
MR. FAGAN:
A. But they include flows of surplus power through the Nova Scotia path.
MR. FITZGERALD:
Q. Okay. And by our math, I guess when we looked at these two tables in combination, it appears in a general sense that they do reveal what the average kilowatt hour price is, and I think, and correct me if I'm

wrong, but we've calculated it to be about 3.5 cents per kilowatt hour?
MR. FAGAN:
A. Yeah, that sounds reasonable. The exact computations are embedded in the numbers that we have here.
MR. FITZGERALD:
Q. Right, right, so we have to disembed them, if that's such a word. And as we see, you know, looking at the embedded calculation, if you will, we've calculated about five, by 2030. It's about five cents a kilowatt hour, does that resemble what you recall?
MR. FAGAN:
A. Yes, subject to check, I'd have to go through and just do the basic math. Whatever that basic math looks like putting these numbers together, that's the answer. There's no question there.
MR. FITZGERALD:
Q. Okay.
MR. FAGAN:
A. And these are in nominal terms, so you would expect that there would be an upward trend on a nominal basis.

MR. FITZGERALD:
Q. Okay, subject, of course, to the vagaries of forecast, as they go ten years, of course we recognize that they're probably not as accurate as our near term forecast, in a general sense.
MR. FAGAN:
A. Subject to the forecast price, certainly.
MR. FITZGERALD:
Q. So we note that one of the advantages that you've mentioned for CDM, of course, is to free up electricity for export. I believe that's one of the underpinnings of the CDM initiative?
MR. FAGAN:
A. Yes, I would—that's important, the CDM effect on shaving peak, it's probably more important when you look at the benefits of CDM, sizeable, a greater amount of those benefits accrue from the peak shaving value of the CDM.
MR. FITZGERALD:
Q. With the low price, relatively low price and I suppose that's a leading question whether it's a low price or not, but would you agree

that the 3.5 percent or 3.5 cents a kilowatt hour is a relatively low cost for—or price for energy?
MR. FAGAN:
A. It's a relative term. 3.5 percent is relatively low compared to 10 percent and 3.5 percent is relatively high compared to 2.5 cents.
(11:45 a.m.)
MR. FITZGERALD:
Q. Sure, but historically speaking, though, in your experience, the current market and you mentioned this morning I think the northeastern United States, is that generally a low price these days and has been historically?
MR. FAGAN:
A. Yeah, the average wholesale prices have definitely been trending down because of the effect of natural gas prices in the US.
MR. FITZGERALD:
Q. So I guess the question would be, then, you know, why is there a push, if you will, to sell or to export energy at such a low price when it can be purchased here?

MR. FAGAN:
A. Well, as our report indicates, we think the best outcomes are to electrify up here and use the energy internally, absolutely. You can get greater average revenue by doing that up here, but what's left over should be sold. You can't store it, the facilities are just about built, so you have no choice but to export it.
MR. FITZGERALD:
Q. Sure, of course. At page 129 of your report, September 3rd, just the advanced metering infrastructure reference there in paragraph 7. And here you stated that the broad use of AMI to more fully implement marginal cost based pricing across all customers does not appear as economically attractive. Why is that? What were your findings there?
MS. WHITED:
A. Simply that the cost of implementing advanced metering infrastructure is still fairly high. We estimated approximately $300.00 all in per meter and the benefits in jurisdictions that typically implement AMI

often include large meter reading savings. We understand that Newfoundland has recently implemented automated meter reading, AMR, and so there are fewer benefits on that end. So that's something that needs to be taken into effect, whether the other benefits that AMI might provide and in the absence of those meter reading savings, may make it less economically attractive then in other jurisdictions where those are available.
MR. FITZGERALD:
Q. Okay. Alternatives to AMI, had Synapse considered the implementation or the recommendation for seasonal rates, would that be a method of achieving rate mitigation?
MS. WHITED:
A. Seasonal rates with, for example, higher prices in the winter verses lower prices in the summer are possible, but there's not much shifting of load that you can do from the winter to the summer, and so, for that reason, you know, the average rate is not going to change, it's not going to provide much mitigation benefit.

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MR. FITZGERALD:
Q. So not something you would recommend?
MS. WHITED:
A. No.
MR. FITZGERALD:
Q. Would AMI in a more sort of isolated or particularized application be effective? For example, if you recommended that they were used for Industrial Customers or General Service 2.3, could it be cherrypicked that way to give an advantage?
MS. WHITED:
A. I would recommend that it be studied. It really depends on the type of system and whether you can reduce the backend costs enough to make it worth your while. Oftentimes those backend costs are relatively fixed, despite how many meters you have to install; however, I understand that industry is developing rapidly, coming up with new solutions, new types of software, that might be more modular in nature, so I would recommend that that be studied.
MR. FITZGERALD:

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Q. Okay, thank you. And does Synapse have an opinion on the effectiveness of demand charges built into rates?
MS. WHITED:
A. Demand charges for large C&I customers have been widely used and those types of customers frequently have some type of energy management system where they can relatively easily respond to those types of charges. What we have seen on the Residential side is that demand charges are not well understood and they often result in a lot of customer confusion and dissatisfaction. So I would recommend first moving to something that's a little bit more understandable, like time of use rates with critical peak pricing, demand charges for the Residential cost could be studied, but another factor that cautions against using demand charges for the Residential class is that their demand is most relevant on a quinstant peak basis, rather than a non-quinstant peak basis and so you want to make sure that the demand charges are reflecting the quinstant peaks and not just non-

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quinstant peaks.
MR. FITZGERALD:
Q. We understand that Newfoundland Power charges its general service 2.3 and 2.4 customers monthly demand charges based on each of their rate payers maximum use in the month. Is that practice a useful element in rate design?
MR. FAGAN:
A. I'll let Melissa answer it, but I just want to emphasize that our analysis and our charge from the reference questions was not to dive down into these types of detailed rate design questions, but with that caveat.
MR. FITZGERALD:
Q. Okay.
MS. WHITED:
A. For larger customers who are accustomed to these types of charges, they can be useful. I think what you just referenced is a non-quinstant peak demand charge based on the customer's highest usage in the month and any hour, as opposed to during the hour of the month or the window of each day where the peak is likely to occur. So, it depends

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on what types of costs you're trying to reduce. If you're trying to reduce the overall system peak, then you want to make sure that your demand charges are set at least partially based on Quinstant peaks as opposed to only non-Quinstant peak demand charges. So, in short, it depends on the details of how that's designed.
MR. FITZGERALD:
Q. Okay, fair enough. Thank you, Madame Chair. Those are our questions. Thank you very much.
CHAIR:
Q. Thank you, Mr. Fitzgerald. Mr. Coxworthy.
MR. COXWORTHY:
Q. Yes, thank you, Madame Chair, Commissioners. Good morning.
MR. FAGAN:
A. Good morning.
MR. COXWORTHY:
Q. My name is Paul Coxworthy. I'm counsel for the Island Industrial Customer Group. At the outset of your evidence, you outlined your experience as being in 19 US states and six Canadian provinces. With reference to

it, perhaps we could turn to it, Figure 53 of your report. I think it's about page 119. Page number may have changed with the revision.
Am I right in saying that you are advocating for directionally the options that are at the right end of that table or that figure?
MR. FAGAN:
A. Advocate is a strong word. We do recommend that the Province look at the combinations of CDM and electrification because we think those hold the biggest benefit. That Figure 53 is one representation of putting all of this together and seeing where things lie. So, I guess the short answer is yes, it's our strong opinion that both of these components are important and both of them are required in some form in order to lead to the best outcome for rate payer.
MR. COXWORTHY:
Q. And again, is it fair to say, looking at this figure, that at least part of the reason why you're strongly recommending the directional solutions, I'll call them, at

that end is that they relatively maximize utility revenue and relatively minimize, in fact absolutely minimize, energy expenditures?
MR. FAGAN:
A. In short, it certainly indicates best customer outcomes on the right-hand side of this graph. It's not quite the maximum utility revenues, but it's close.
MR. COXWORTHY:
Q. That's right. It gets you closer than some of the other results, closer to maximizing your utility revenues.
MR. FAGAN:
A. Well, I mean, you can see from this, the pure maximization of – well, I should be careful here. The maximization of utility revenues comes with the electrification only scenarios.
MR. COXWORTHY:
Q. And -
MR. FAGAN:
A. The maximization of customer benefit comes from the combination.
MR. COXWORTHY:

Q. And in short, why is it important to, if not have an absolute maximization of utility revenues, to keep them relatively high? Why was that part of your analysis?
MR. FAGAN:
A. It's important from a mitigation perspective. From a rate mitigation perspective that's important. From a bill mitigation perspective, the combination is important.
MR. COXWORTHY:
Q. So, it's important for both, for bill mitigation to have relatively high utility revenues? That's an important goal as well, as much as reducing energy requirement, absolute energy requirement?
MR. FAGAN:
A. Well, it's both of those things. You know, reducing consumption and for those areas where electrification can occur, displacing oil with more efficient use of electricity for the end-use service needed, that's what gives customers the best outcome.
MR. COXWORTHY:
Q. With reference, I started off by addressing

your experience in other jurisdictions. Are you aware of any other jurisdictions that you've worked in where this type of directional approach has been implemented? The directional approach that appears in the last five bars on Figure 53.
MR. FAGAN:
A. Maybe I'll let you answer that. I mean, there's many jurisdictions where both electrification and energy efficiency have been looked at together, perhaps not necessarily with this -
MR. COXWORTHY:
Q. I guess my first question was anywhere that it's actually been tried, not just looked at, but used, implemented for a period of time.
DR. HOPKINS:
A. I'll mention the US states of Vermont and Massachusetts as examples. In the Vermont case, there's a strong policy push towards electrification. They have a lot of oil heat, so the economics of heat pumps are relatively favourable. They're a ZEV state. They're signed on to the California Zero

Emission Vehicle policies towards electric vehicles. They're also among the states that they have been recently ranked number three in the US on electric energy efficiency. So, they're, you know, really pushing very hard on both of those directions.

Massachusetts, number one on energy efficiency in the US, has recently implemented heat pump incentives through its energy efficiency programs. Is also a ZEV state; has electric vehicle incentives, et cetera. So, they're similarly pushing on both the electrification and the energy efficiency side of the ledger.

MS. WHITED:
A. And I would add California as well.
DR. HOPKINS:
A. Oh, right.
MR. FAGAN:
A. Yeah, I mean, California, all three of these components are in place in California. California has traditionally been one of the leading energy efficiency states. They've had significant inroads, probably more so

than any other state, on electrification for vehicles and they have been at the forefront in rate design efforts over the years to try to get the right price signalling in place.
MR. COXWORTHY:
Q. So, in California, is it rate design that's been coupled with electrification to achieve these results or is it CDM?
MR. FAGAN:
A. It's all. California looks holistically at energy efficiency policies, at electrification and electric vehicle policies and rate design across a whole plethora of proceedings in California. It's hard to keep them all straight. But they look holistically at all of these elements.
MR. COXWORTHY:
Q. California, in terms of the size of the market, the issues that they face, load shapes, customer class, et cetera, is it comparable to Newfoundland and Labrador?
MR. FAGAN:
A. It's obviously different in many respects, but at its core, electrification and energy efficiency and rate design is sort of

universal across all of the jurisdictions, I think, in Canada and the United States and elsewhere in the world.
MR. COXWORTHY:
Q. So, one to one, you think the lessons that they're drawn from a jurisdiction like California will apply in Newfoundland and Labrador? That's a reliable measure; that the success that's been achieved in California can be expected here?
MR. FAGAN:
A. They don't directly apply in the sense that a lot of things are different. You know, the dominant – you know, solar is – I mean, California has a significant share of hydro also, both its own hydro and imported hydroelectricity and they also have significant amount of both wind and solar. The demographics are different. It's a summer peaking system, not a – although parts of northern California are winter peaking actually. So, there's a lot of differences. But what's more stark are the parallels and the analogs you can draw because at a fundamental level, the

technologies, heat pump technologies and the electric vehicle technologies and the regulatory impacts of smart rate design can reap the benefits regardless of whether or not it's California, North Dakota, Florida or Newfoundland.
(12:00 noon)
MR. COXWORTHY:
Q. All that you just mentioned, imported electricity. One of the factors in California is their ability to import electricity and in fact, that's probably – I think that's probably true of all of the examples you've just given, Vermont, Mass, they all have access, ready access to imported electricity from outside of their jurisdiction.
MR. FAGAN:
A. Yeah, California certainly imports and exports – they're net imported, but seasonally there are significant export also. Sure, all jurisdictions are -
MR. COXWORTHY:
Q. And how important is that, the flexibility to be able to import electricity from other

jurisdictions, to achieving the types of results reliably that you're advocating for?

MR. FAGAN:
A. To achieve the types of results that are listed in this report, what's required is you need to have a path for exporting surplus energy.

MR. COXWORTHY:
Q. Just for exported? Is imported electricity important?

MR. FAGAN:
A. Primarily for exporting surplus energy. You also have a path to import electricity. But with this, this is demonstrating the value of exporting surplus electricity in part along with the other elements.

MR. COXWORTHY:
Q. Going back though to the factor of imported electricity in these other jurisdictions and the flexibility that gives if you have access to cheaper electricity from other markets. Do we have that in Newfoundland and Labrador? Will we have that in Newfoundland and Labrador, based on the information you have?

MR. FAGAN:
A. I think that's less a part of the equation in Newfoundland, absolutely. You know, you now have your own – or will have your own close to zero marginal cost electricity to serve all of your needs. So, you're – you won't need the imported electricity as much as some other jurisdictions that don't have the resource base that you have.

MR. COXWORTHY:
Q. If we could turn to Table 1 of your presentation, at page 18 I think. And this is just an example, but throughout your presentation, throughout your report, you refer to average customers, average rate mitigation, average electric bill. Are Industrial Customers included in that, those averages?

MR. FAGAN:
A. Yes, all customers are in that average.

MR. COXWORTHY:
Q. This average customer, how many Hydro customers are within the band or relatively closely within a band of average customer? Are we talking about fairly wide extremes to

arrive at an average?

MR. FAGAN:
A. This is a system wide analysis. So, average customers means the entirety of the customer base and the variances in consumption patterns and levels of consumption vary across all of the rate classes.

MR. COXWORTHY:
Q. Sure.

MR. FAGAN:
A. And I think we've made this clear that moving forward, looking at the distribution of these effects across the rate classes is important and depends upon more than just what we've been able to analyse in this set of reference questions. But, the average customer presentation gives you a good idea of the overall direction and magnitude of mitigation impacts under different scenarios for different policies.

MR. COXWORTHY:
Q. I guess that's what I'm trying – why should we accept that using these average figures are actually going to give us a good indication?

MR. FAGAN:
A. Because of the underlying fundamentals. The underlying economic fundamentals around electrification, around CDM and around rate design impacts hold. As soon as you drill down into the rate classes, you do indeed have to be careful to minimize inequities that can otherwise arise, absolutely. There's no question about it. That's the challenge in front of you.

MR. COXWORTHY:
Q. But you're assuming that they'll be roughly similar take-ups of electrification, of CDM, both as amongst different customer classes, as well as within individual Industrial classes. That that's going to be possible through technological solutions or policy decisions. That's your assumption in putting forward these average projections as being indicative of the direction that this Province should go in, in terms of mitigating rates?

MR. FAGAN:
A. It's not an assumption per se. In order to minimize the inequities, you will have to

think carefully about the CDM policies and the electrification policies and how you allocate costs across groups of customers. These are thorny questions. There's no two ways about it. But, the fact that this analysis is focused on an average customer, you know, in no way minimizes the importance of both the magnitude and the direction of the overall effects that are possible. You know, with the important caveat that, you know, your work is not done. You have to pay attention carefully to what you do on all of these fronts and they're not – you know, they're not – each of these areas, rate design, electrification and CDM, comes with its own set of challenges. Some of which are more easily handled than others. But, you know, there's no question about it that it's not a slam dunk. You have to be careful. But absent doing anything, you will have inequities unfold. If there were no policies at all on electrification or CDM, there's – but you have the rate increases that are going to be required, you're going to have movement and you're

going to have some sort of a distributive effect across all of your rate classes. So, our recommendation would be to grab that bull by the horn, so to speak, and continue to think carefully and look at what you have to do to minimize inequities that could occur, absolutely.

And both CDM and electrification programs in other parts of North America grabble with this and, you know, CDM in particular, there's a whole slew of CDM-like design approaches that should be considered. I mean, you're a less aggressive province with respect of, for example, the leading states and even the leading provinces, I believe. There's important lessons that you can learn. But it's not a simple undertaking.

MR. COXWORTHY:

Q. No, and that's understood. But is there any other jurisdiction – I know you've been pointing to California as being a good example, but is there any other jurisdiction similar to – that's facing similar issues to Newfoundland and Labrador that you can point

to and say here's a model? You couldn't apply it exactly to your situation, but that could be patterned to the Newfoundland and Labrador situation? Is there any jurisdiction that you're familiar with that it would be useful to look to or do we really have to pick and choose and come up with a bespoke model here for what you're trying to achieve?

MR. FAGAN:

A. Well, I think it's almost a bespoke model, but the components of that model are fairly well understood, even though there – my general sense is no. There's very few jurisdictions in North America that are facing exactly what you're facing, you know, clearly. You know, a new large hydroelectric project that's over budget and there's this big rate shock. There's no two ways about it, and you're at the terminus of the system. But all those things notwithstanding, the lessons learned from the other jurisdictions still apply. The EV and the heat pump technologies are still there for your taking. The rate design

approaches exist and the information is out there. So, as much as it's difficult to try to draw a parallel with any other jurisdiction, be it state, region or province, that doesn't make the lessons learned in those other regions and the broad implications of this analysis any less effective.

MR. COXWORTHY:

Q. You say there's a lot more work left to be done; that would need to be done to reasonably implement some of the directional solutions that you're strongly recommending. How much of the work have you been able to do? I mean, have we just scratched the surface?

MR. FAGAN:

A. I think we've done more than scratch the surface. I think putting your finger on the potentials involved is important. I think that, you know, the work that Dunsky has just completed is an important element of that work that the Province needs to do.

Just being able to put in one place sort of a clear balancing of the energy flows overtime, given what's going on with potential for a flatter load and given what the possibilities are for increased electrification and reduced energy from CDM, just putting that in one place is more than scratching the surface. I would say that, you know, to use that same analogy, you know, perhaps – you know, beginning of Phase 1, we were – and even into the conclusion of Phase 1, we were scratching the surface. So, the putting it together, the synthesis involved in coming up with Table 1 and 2, for example, helps to shine a little bit of a more focused light on what the concerns are and what the potential remedies are. But diving down into the rate class and the thorny issues of how you implement policy to minimize inequities, that's the next step, and that's essentially what we laid out in the series of next steps there that the Province will need to tackle.

MR. COXWORTHY:

Q. Synapse has been involved in this process for the better part of a year to arrive at the point you've arrived at. I think it's

understood with good cooperation from Hydro, Nalcor, Newfoundland Power, that the information you've asked for has been provided. If you were to be tasked, similarly resourced, with similar cooperation from Nalcor and Hydro, to take this analysis to its end point, to the end point of digging down, drilling down into class effects, to drilling down to what actually is implementable, both reasonably and in terms of having some reasonable certainty, in terms of outcomes, how long would that take you? If it's taken you the better part of a year to get to where you are now, how long would that take? Would it take another year, two years?

MR. FAGAN:

A. It would depend upon the specific scope, certainly less than two years to begin to put this – you know, get to the next level of focus. It's hard for me to put a number on that. You can do a lot of work in a year.

MR. COXWORTHY:

Q. But you're saying perhaps two years?

MR. FAGAN:

A. I mean, for example, the results of Newfoundland Power's load research study, that would be really important to really help inform this. If you wanted to do some pilot programs to look more carefully at response to TOU, those things take time. So I think that type of data collection would be important to the accuracy of the finished product, absolutely. Not to mention just, you know, are you going to be good with the LIL over the next five years, over the next two years, over the next ten years, and what more will you know six months, eighteen months down the line, and how might that impact how important particular peak shaving things are. You know, are there any significant changes in export markets. We actually don't think that there will be. I think it's more about what's happening internally and what your load research may tell you. That might be one of the more important pieces of data that would be useful to have to try to flush this out. I mean, some of the rate design stuff is

somewhat academic, you can do it, but it's all going to depend upon the type of data you have access to, to test how accurate the results actually are.

MR. COXWORTHY:

Q. If we could turn to page 39 of your presentation. Thank you, the table with the CDM adoption rates of technologies, low and high scenarios, and I wanted to ask some questions about the third band for the island there, which I understand to be for industrial customers.

DR. HOPKINS:

A. Correct.

MR. COXWORTHY:

Q. The IND?

DR. HOPKINS:

A. Yes.

MR. COXWORTHY:

Q. Yes, thank you, and I wanted to have your comment on how you've arrived at the projections of 14.5 percent for 2030 under the base case, and 25.8 percent under the low rate case, and 40.1 percent for the high case by 2030?

DR. HOPKINS:
A. Just to make sure we're on the same page, what's showing here, this is the accumulative adoption rates for CDM measures on average by those dates starting from 2019, and so in the base case, we basically assumed that programs continue as they are.
MR. COXWORTHY:
Q. Existing programs for industrial customers?
DR. HOPKINS:
A. The existing programs, so the 1.3 is the current level of performance, as I understand it. So if that were to continue for eleven years, that's 14.5. If participation rates and adoption rates of CDM measures were to increase gradually over time, then the cumulative of that you get over time is somewhat higher.
MR. COXWORTHY:
Q. And are these the same existing measures, or are you assuming there'll be new measures for the low case?
(12:15 p.m.)
DR. HOPKINS:
A. If you go back to the previous slide,

there's a list of measures that we looked at. Industrial end uses identified here, so motors, compressors, pumps, fans, process, energy use, HVAC, lighting and other, and so for each of those looked at adoption rates. Where adoption rates are relatively high now, the relative increase is smaller. Where adoption rates have been relatively low, the relative increase is higher, but, yeah, we looked at each of those end uses and the potential in those areas, and what plausible paths forward might be for increasing uptake relative to the, sort of usual base case.
MR. COXWORTHY:
Q. It's not clear to me, and perhaps it's my fault, but is the low case for 2030 based on existing = extrapolating take up of existing CDM programs that Hydro is offering to its industrial customers?
DR. HOPKINS:
A. The existing programs, I'm not sure whether it's limited only Hydro's in the sense that there are some industrial customers, smaller ones, served by Newfoundland Power, but the

suite of measures is the ones listed on the previous slide. Generally industrial energy efficiency tends to be lumpy, come in large chunks of reworking of a facility or reworking of a production line, or that sort of thing. So this is smoothed out and also industrial energy efficiency tends to be outcome focused rather than – we're dealing with, like, a large industrial facility, do not necessarily have a – it's commonly a custom approach to what that particular facility needs, whatever its particular blend of end uses are. So I think we were working more from a top down – sort of top down meets bottom up, what seems like a reasonable combination of what's possible in those measures, and recognizing that we're not actually in the particular facilities doing site assessments ourselves.
MR. FAGAN:
A. But the low is not just an extrapolation of existing programs. It's a small tweak in addition the existing programs.
DR. HOPKINS:
A. The same measures may be being adopted as in

existing programs, but at a more rapid click, recognizing perhaps somewhat larger incentives are the things that might be necessary to make those same kinds of things happen, but faster.
MR. COXWORTHY:
Q. You said something in the course of that answer, and I understood you to say, and correct me if I'm wrong, that within that industrial band there, there's perhaps included some Newfoundland Power customers. It's not what we – at least, I think of as industrial customers of Hydro. It's not strictly speaking just that industrial customer class that's included in that band?
DR. HOPKINS:
A. In terms of energy use, it's overwhelmingly dominated by the large customers. Whether on the margins – I'm just forgetting at the moment whether we looked at Newfoundland Power customers in that piece or not.
MR. COXWORTHY:
Q. So you don't know, or you can't tell us right now?
DR. HOPKINS:

A. I would say that the analysis is for the island as a whole.
MR. COXWORTHY:
Q. Yes, for energy consumption, I certainly would understand that obviously the Hydro industrial customers would, but in terms of the information you're presenting here in terms of adoption rates and technologies, is this preponderantly reflecting take up of that by Hydro's industrial customers?
DR. HOPKINS:
A. Yes.
MR. COXWORTHY:
Q. And then under the high case to get the 40.1 percent, is that extrapolating even greater take up of existing – what is factored into that to get to that figure?
DR. HOPKINS:
A. That's basically just that much further take up of those same kinds of measures, whether they're motors, compressors, pumps. The kinds of end uses that exist in those facilities are roughly the same. It's just a question of whether participation in programs to actually achieve those savings

goes just that much faster.
MR. COXWORTHY:
Q. Are these percentages that are portrayed on this page, are they based on historical or statistical adoption rates from other jurisdictions? Have you brought the experience of other jurisdictions and industrial customers take up of these types of programs to this analysis, or is it purely based on looking at what's happened so far in Newfoundland and Labrador and extrapolating from that?
MR. HOPKINS:
A. It's informed based on potential studies which take into account what's achievable, and which draw upon the lessons learned from what's achievable in all different jurisdictions around the country. I don't think we have any – there's no particular model example on which it was based, but it's a question of what is an achievable level of program participation that might be achievable over time with aggressive CDM program.
MR. COXWORTHY:

Q. Do you know whether those studies drill down to the level of looking at particular industrial sectors? I mean, the industrial customers that we represent, an oil refinery, mineral ore refining, pulp and paper, are there differences from industrial sector to industrial sector in terms of capacity to take up these types of CDM opportunities?
DR. HOPKINS:
A. Yes, there are definitely differences. We reflect those – well, for things like HVAC and lighting, a building that's an industrial building is roughly comparable to a building that is used for some other purpose, but for things like motors, compressors, processes, et cetera, there would be differences. We based the potential in this case on a USD assessment from the mining industry to try to capture the relatively sort of heavy industry nature of the industrial sector here in Newfoundland, but we did not break it out specifically, pulp and paper versus refining. If we did that, we'd basically be

trying to do it at a facility by facility level. Because there's so many facilities, you would be quizzing us on where we got our exact data on pulp and paper from a particular facility.
MR. COXWORTHY:
Q. So there's a USD category for the mining sector?
DR. HOPKINS:
A. Right.
MR. COXWORTHY:
Q. Is there one that's pertaining to oil refineries, in particular?
DR. HOPKINS:
A. There may be. I don't remember exactly going back into how exactly they're broken out. There's a question of data availability of trying to find some sort of comparable historically.
MR. COXWORTHY:
Q. Just broadly speaking, is it typical that industrial customers, users like oil refineries, or mineral ore processors, or pulp and paper mills, that they're able to tailor their operations and still maintain

their levels of economic production, but is it typical that they're able to tailor their operations to substantially reduce their electricity consumption while maintaining their levels of economic production, whatever product they're producing? Is that typical?

DR. HOPKINS:

A. There are definitely process improvements, particularly from my understanding, in motor efficiency and pump efficiency using variable speed drives and other things where you're taking advantage of physics to try to improve those pieces. There is a very common intention, which you were identifying, which is the need to maintain output. You can't shut a production line for a month to retool it to get a 1 percent improvement. That doesn't make sense, and so there's always those kinds of trade-offs which is why the achievable potential is usually substantially less than the technical potential.

MR. COXWORTHY:

Q. And so with that in mind, that the

achievable potential is usually less than what might be technically feasible or possible, again at page 39 of your presentation and the table there and the take up rates, is that what is technically possible or is it your assessment of what's practically achievable?

DR. HOPKINS:

A. So there are assumptions on what savings are achievable by end use on Table 17 on page 59 of the report. For example, for motors, compressors, pumps, fans, process, and HVAC, the potential there is 20 percent. So in the case where you have 40 percent uptake of a measure saving 20 percent, that's something like 8 percent overall saving in that end use, so we're taking what's technically possible in terms of – and achievable in this percentage savings piece and also modulating it by the fact that it takes time and an adoption may be slower or faster and thus the range of potential outcomes.

MR. COXWORTHY:

Q. So you're assuming you'll get there or you

should be able to get there eventually?

DR. HOPKINS:

A. If 20 percent savings are there and are cost effective, over time when you want a production line or a portion of the refinery or the pulp and paper facility is refit sometime over the course of years, that maybe you capture that opportunity. I mentioned the lumpiness of industrial efficiency acquisition previously. So it's a question of being ready and capturing those savings when you can find them and when they work for customers.

MR. COXWORTHY:

Q. Ms. Whited was speaking to rate design, and in the course of her evidence she talked about New England jurisdictions as being example where time of use and critical peak pricing has been implemented, those rates have been implemented and used. I think that's correct?

MS. WHITED:

A. I was speaking about – well, the time of use with critical peak pricing, they've have been implemented in many different

jurisdictions. What we used to calibrate the type of response that we would see in Newfoundland were Ontario, Quebec, and the Pacific North West, specifically Portland Gas and Electric in Oregon.

MR. COXWORTHY:

Q. And so those are examples of jurisdictions where time of use and critical peak pricing has been used – had experience in using it?

MS. WHITED:

A. That's correct.

MR. COXWORTHY:

Q. And, I guess, I'd like you to comment on the experience of industrial customers in those jurisdictions in terms of do they take up time of use, critical peak pricing, is it different from what's implemented for other customer classes?

MS. WHITED:

A. Certainly time of use has been much more widely implemented for large CI customers than for residential customers across all the jurisdictions that I'm familiar with, and so often those time of use programs have been in place for many years and may be designed slightly differently than the time of use rates for residential customers.

MR. COXWORTHY:
Q. And what's the usual difference in terms of between what might be designed for retail customers, or what are some of the differences in the design of those rates?

MS. WHITED:
A. It can certainly vary by jurisdiction. Some more legacy time of use rates may have longer on peak and off peak windows as opposed to shorter ones for residential customers. There may be higher or lower price differentials for residential customers. You know, there's often a concern about gradually implementing the time of use rates, whereas when they've been implemented for many years for large customers, you don't have as much concern about introducing the new rate.

MR. COXWORTHY:
Q. And In looking at the situation in Newfoundland and Labrador, have you come to any even initial conclusions as to whether time of use rates, critical peak pricing,

would be useful in relation to the island industrial customers?

MS. WHITED:
A. And I understand it, there are some demand response programs in place that you'd want to consider as to whether or not you are supplementing those programs with rate design or if you are replacing those programs. So a lot of times you'll have time of use rates, but perhaps without the critical peak pricing component because you might have a demand response type of component instead.

MR. COXWORTHY:
Q. Thank you. I have no further questions, Madam Chair. Thank you.

CHAIR:
Q. Thank you, Mr. Coxworthy. Ms. Greene, do you have anything on follow up?

GREENE, Q.C.:
Q. No, I do not. Thank you, Chair.

CHAIR:
Q. And I don't have any questions, so, I guess, thank you very much for your efforts on our behalf. Ms. Greene, do we have anything

else today?

GREENE, Q.C.:
Q. No, Madam Chair. We have now concluded the part of the hearing where we present the evidence that we had of experts to undertake. The next witness on the schedule would be Mr. Stan Marshall, who I understand will be commencing tomorrow morning at 9.

CHAIR:
Q. Okay, we will adjourn and reconvene tomorrow morning at 9 a.m. Thank you, panel. Safe travels home.

(UPON CONCLUDING AT 12:32 p.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 7th 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 7th day of October, 2019

Judy Moss

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