COMMISSION OF INQUIRY
RESPECTING THE MUSKRAT FALLS PROJECT

Transcript | Phase 3 Volume 2

Commissioner: Honourable Justice Richard LeBlanc

Wednesday 17 July 2019

CLERK (Mulrooney): All rise.

This Commission of Inquiry is now open. The Honourable Justice Richard LeBlanc presiding as Commissioner.

Please be seated.

THE COMMISSIONER: All right. Good morning.

Mr. Collins.

MR. COLLINS: Commissioner, could we enter exhibits P-04445 –?

THE COMMISSIONER: Just one second now. Go again. P –?

MR. COLLINS: 04445 and P-04464.

THE COMMISSIONER: Okay. Those will be marked as entered. And –

MR. COLLINS: And I believe – the next witness, I believe, wishes to be affirmed.

THE COMMISSIONER: Okay. So, Mr. Colaiacovo, if you could stand please? Be affirmed.

CLERK: Do you solemnly affirm that the evidence you shall give to this Inquiry shall be the truth, the whole truth and nothing but the truth?

MR. COLAIACOVO: I do.

CLERK: Please state your name.

MR. COLAIACOVO: Pelino Colaiacovo.

CLERK: Could you spell your last name, please?

MR. COLAIACOVO: C-O-L-A-I-A-C-O-V-O.

CLERK: Thank you.

THE COMMISSIONER: All right. Mr. Collins, when you're ready.

MR. COLLINS: Mr. Colaiacovo, could you begin by outlining your education and experience?

MR. COLAIACOVO: Sure. I have an undergraduate degree in economics and politics after which I did a law degree. Chose not to pursue a legal career, but I spent 10 years doing policy consulting, primarily at the Ontario level, the federal Canadian level and United States federal level with a policy consulting firm, largely in energy transportation and telecommunications policy. Then I was in government for two years as chief of staff to the Ontario minister of Energy, and for the past 14 years, I've been with Morrison Park Advisors doing investment banking primarily in the electricity sector as well as other utilities such as natural gas pipelines and water utilities.

MR. COLLINS: Thank you very much.

And I believe you've prepared a report, which is Exhibit P-04445.

MR. COLAIACOVO: Correct.

MR. COLLINS: Which is tab 1. And if you go to tab 2, I believe you've prepared a presentation or a slide show which summarizes or explains your work and findings.

MR. COLAIACOVO: In some detail, yes.

MR. COLLINS: And are you able to walk us through that?

MR. COLAIACOVO: I'd be happy to.

MR. COLLINS: So could we bring up P-04464?

MR. COLAIACOVO: I apologize in advance for my voice. I'm coming off of having a flu so I'm a bit raspy. And I may occasionally cough but I'll be able to walk us through the presentation and answer questions as required.

THE COMMISSIONER: If you could just speak up, just a little bit.

MR. COLAIACOVO: Sure.

THE COMMISSIONER: Okay.

MR. COLAIACOVO: The presentation is divided up into nine sections. The first couple I will run through very quickly and then I'll work through the rest of it slide by slide. It goes through my report in some detail. I'll be expanding on slides as we go. I can be interrupted at any time, obviously, with questions or, alternatively, just answer questions at the end. I will try to not get bogged down and keep people awake as I go through this. Some of it's kind of technical in nature.

But the background on MPA: We are an independent, partner-owned investment bank based in Toronto, 14 professionals. We're essentially considered a boutique. We specialize in surveying public companies that are at the smaller end of the public company scale, private companies, as well as governments and agencies in the public sector, not-for-profits. We primarily focus on mergers and acquisitions and on capital raising. We also have a thriving subspecialty in evaluations and opinions. We work for independent committees of corporate boards for transactions, as well as for regulators and for governments.

About 50 per cent of all of our business is in the utilities and power and infrastructure sectors. We also have thriving practices in mining and technology and a couple of other areas.

I've been with the firm since 2005, as I mentioned. I've appeared on utilities-related cases in both Nova Scotia and Manitoba. I've provided advice to governments and agencies in Ontario, Saskatchewan, British Columbia and Alberta in addition to those regulatory appearances. As I mentioned, I was at one time, earlier in my career, chief of staff to the Ontario minister of Energy during a particularly tumultuous period in the development of the Ontario electricity sector, so I'm very familiar with the kinds of decision-making that go into major projects at the provincial level.

THE COMMISSIONER: Can you – just before you move on, I also am aware of the fact that Morrison Park had involvement in – with Emera in Nova Scotia related to the Maritime Link in appearances before the UARB. Were you personally involved in any of that?

MR. COLAIACOVO: I was and, in fact, we were working for the regulator. We were an expert witness to the UARB on the Maritime Link, and provided a fairness opinion on the Maritime Link transaction for Nova Scotia.

THE COMMISSIONER: Okay. Thank you.

MR. COLAIACOVO: The scope of work that we were asked to cover for this Inquiry was four parts: The review of the role and importance of some critical financial assumptions in that 2012 decision-making process, in particular covering load, fuel prices and energy export prices; comment on the use of the cumulative present worth metric in the analysis that was done in 2010 and 2012, particularly in the context of alternatives and the conclusions that might have been drawn from those other kinds of alternative metrics; comment on the decision to dismiss all alternatives other than the chosen plan and the Isolated Island plan and, in particular, dismissing the possibility of importing electricity from Quebec; and finally comment on the potential relevance and financial terms of the Muskrat Falls project on the future of the Churchill Falls generating station, in particular after the expiry in 2041 of the existing arrangements that applied to that generating station.

I am going to cover all of these issues over the course of my presentation, as I did in the report.

MR. COLLINS: Commissioner, to the extent that it is necessary, the Commission is presenting Mr. Colaiacovo as an expert in utility transactions and in corporate finance related to utility transactions. And that's the purpose of his background and that's the nature of his scope of work.

THE COMMISSIONER: Okay.

Is any party taking – or wish to ask any questions related to Mr. Colaiacovo's expertise or ability to provide opinion evidence?

All right, so under the circumstances, I will allow him to provide opinion evidence. I have seen his CV and also the other documents that have come in related to Morrison Park and his work, and I'm satisfied that he can provide opinion evidence in this particular Inquiry.

MR. COLAIACOVO: Thank you.

I wanted to start with a note on financial models and future projections. This has been, I think, quite a controversial issue, as has happened across the country when projects don't go according to plan or according to the way they were advertised prior to the decisions being made.

I think it's important to recognize that all financial models are, in essence, just algorithms. You load assumptions in and inputs come out the other end. There is no magic to financial models. They are, you know, directly dependent on the quality and the sophistication of the assumptions that are loaded into the model. It's just math, in the end.

The Muskrat Falls Project covers a period of 50 years of operation plus initial construction, originally intended to be about 57 years in total.

I think it's important to recognize that trading markets – there are trading markets that operate on a daily basis. Typically, forward markets are heaviest in the three-month to five-year period. People make commercial decisions, commercial bets on commodities prices for three months to five years. The stretch point is 10 years for a forward contract. That's what traders are willing to actually bet on.

Long-term forecasts are typically 10 to 20 years in length. For the Muskrat Falls Project, people were required to make 50-year forward forecast in order for the model to work correctly.

I think it's important to understand that a forecast – quote, unquote – forecast which lasts 50 years is, in essence, meaningless. It's a tool for analysis, it's not a prediction about the future. There can be no predictions about – that go 50 years in the future – that have any significant meaning that you can rely on, so fundamentally – because technology changes so much in 50 years.

I think all you need to do is go 50 years into the past and look at the technology that was available 15 – 50 years ago compared to today, and how the economy has changed over that time period regardless of the sector you're talking about. But in the electricity sector where – there has been particularly strong changes over the last 20, 30 years, much less 50 years.

I think, you know, going backwards is instructive about going forwards. You can't actually make forecasts that are 50 years long. These are just tools, they are assumptions, they are ranges, they are options that you test. They are tools for judgment, but they are not predictions. And I think, you know, the whole idea of financial modelling and financial projections has to be understood from that – in that light, that this is a tool for judgment and nothing more. I think it's very easy to fall into a trap of thinking that financial projection is actually an accurate guide to the future, because it's not and never will be.

So, if faced with a major project decision, what's the typical analytical framework? What is the sort of process to follow? And I skipped forward here to page 10 of the presentation.

First of all, define the primary need which the project is meant to satisfy. There has to be a starting point for considering a project. Identify the universe of potential options to satisfy that need, but then quickly eliminate options that are simply impractical, impossible in a jurisdiction, illegal, not consistent with social values. Many of the universe of potential options can just be dismissed quite legitimately.

Third, identify the costs, benefits, risks and opportunities that apply to each of the viable options. And again, you know, that process will bring to light issues that need to be taken into account in the rest of the process. It will also bring to light, potentially, some problems which might lead you to dismiss even more options.

Fourth, prepare financial models for all the practical options and eliminate the ones that are clearly inferior on that basis. It's important that if a financial model can't take into account all of the costs, benefits, risks and opportunities that were previously identified, that you come up with some other means of analysis to address those issues. You can't simply ignore costs, benefits, risks or opportunities. They have to be taken into account through some form of analysis. It's not always possible to financially quantify them, but they have to be understood and included in the analysis, even if not quantified.

Next, perform sensitivities on all of the variables that you've identified in the financial model to determine which variables are critical drivers of the outcome. You can't focus on every single variable, particularly if a change in a variable is going to have very little bottom-line impact. But a sensitivity analysis will show which variables are the ones that have the greatest impact and, therefore, should be the focus for analysis.

Next, prepare scenarios for the future that – use all of the critical variables and look at all of the different combinations of those variables. The reference scenario, typically, is what's considered to be the most likely, or the central case, or the base case against which all other scenarios are compared and contrasted, but it is critical to explore as many different combinations as possible.

Depending on the number of variables and the ranges of those variables, sometimes it's not practical to run financial models for every single combination. You could be in a situation where you're looking at tens of thousands of potential combinations, in which case you would use what's called the Monte Carlo model. And a Monte Carlo model effectively runs a subsample of the possible combinations that are chosen randomly in order to get a random distribution that represents an average of what all of the potential scenarios would include.

However, if the number of variables is manageable – if you're only talking about three or four variables with a certain range for each variable – you would end up with hundreds or perhaps a couple of thousand different scenarios. Given modelling tools today, that's entirely calculable. There's no reason why a computer can't run through 2,000 or 3,000 different scenarios and produce outcomes for all of them.

Finally, "Analyze the outcomes across all scenarios." For each option, you have to consider the range of favourable and unfavourable scenarios and the likelihood of those scenarios arising. Examine whether project failure occurs in any scenario. Is there an actual bankruptcy? Is there a totally unacceptable outcome that occurs from a particular option in certain scenarios?

In those cases, what are the consequences for stakeholders? Are there mitigation options possible for stakeholders in those scenarios? How fatal is it to have project failure? You have to understand what those consequences are and take them into account in the analysis.

Finally, make a judgment. No option is ever going to be superior in every scenario. It's – you wouldn't be going through the process if that was the case. If you – you know, early in the stage of the analysis, if you dismiss every option and you're left with only one, you wouldn't even get to the point of running scenarios; you wouldn't get to the point of financial modelling. But if you are doing financial modelling and you are running scenarios, then one option will never be universally superior. There will always be scenarios on both sides.

And so a choice, in the end, requires judgment. It requires judgment about which scenarios are more likely, which risks people are willing to take, how the outcome affects different stakeholder groups and to what degree and are those outcomes manageable. And so it's a judgment call in the end. As I said, financial projections and tools and financial models are all just aids to judgment, but judgment in the end is always required.

So who are the audiences for this kind of analysis? Well, clearly investors – investors putting the money into project – putting equity into a project and expecting returns over time. Customers and regulators, in the case of regulated industries, will be responsible for paying the bills of the project over time and may not have any recourse to other forms of mitigation depending on the circumstances in the situation.

Government, where it's not a direct participant, either as an investor or as a customer, will often have ancillary benefits associated with the project or ancillary impacts, such as tax revenue, fees, charges, licences, environmental impacts, local jobs, First Nation's impacts: there's a hundred potential different ancillary impacts and outcomes that would be important to governments. And, finally, debt providers who will look at all these models to better understand risks so they can price their debt accordingly.

The metrics that are considered depend on the particular audience. For investors, internal rate of return or the average return on investment over time on a discounted basis is an obvious important indicator. NPV, or net present value, provides the absolute magnitude of the profit expectation on a discounted basis. So choosing between two projects, you might prefer a project that has a higher return – a 15 per cent return instead of a 10 per cent return.

But if the project is small, if it's a million dollars of investment, it's only going to provide that 15 per cent return on the initial million dollars. A second project that has only a 10 per cent instead of a 15 per cent return might require a $10 million upfront investment and represents a much larger profit opportunity simply because of scale. And so the NPV is actually superior and they're two different kinds of metrics that can steer investors in different directions.

A third one is simple payback. And simple payback refers to the number of years that are required until the initial investment is repaid. That is a sense – a measurement of risk. How long is your capital at risk before it's initially paid back?

For customers, the primary issue is cost and we'll get a further discussion of cost in a moment. For government, the metric really does depend on which ancillary impact is being considered, whether it's jobs or First Nations payments or environment or what have you. And for debt providers, they're focused on very similar indicators as investors are.

In terms of cost analysis, in my report I talked about the CPW analysis, which is cumulative present worth. That was used in the 2010 and 2012 processes by Nalcor in their decision-making analysis. CPW, or cumulative present worth, is a discounted total cost of a project over its entire life or some specified period of time, whether it's a life of an asset or not. And that's only one of a dozen different ways to understand costs.

Costs can be understood on a time basis, either annually or over a certain period of time. Costs can be understood in nominal dollar terms, which is how customers will experience those costs from year to year. They can be understood in per-unit terms because when people think about prices, they think about the price of a unit of something, as opposed to necessarily their total cost at the end of the month, if their usage can change from month to month or over time.

It can also be inflation adjusted is another way to think about it because, again, people experience costs in the context of all of the other costs that they face; they experience changes of costs in the same context. And so if a project has costs that are rising at inflation, customers won't experience those costs as rising per se because, presumably, their incomes are rising and their other costs are rising at approximately the same rate.

And, finally, discounted costs, of which cumulative present worth is one of those discounted metrics. And discount rates can be chosen in a variety of different ways for a variety of different reasons, which brings up the whole problem of how to choose a discount rate for – whether it's for CPW or – sorry, I should have also mentioned one of the other calculations is something called LUEC, levelized unit electricity cost, which is an electricity industry metric where you discount costs over time by its discount rate and you also discount power consumption by the same discount rate over the same period of time and divide the two. And so you end up with a discounted total cost of power divided by discounted total power consumed over time to end up with a single number that is meant to represent the cost effectiveness or cost efficiency of a particular energy source.

LUECs are used to compare different kinds of technology, typically. So you talk about the LUEC of gas plants versus the LUEC of nuclear plants versus the LUEC of wind farms. That's the – if you're trying to choose which kind of technology to use in a system plan you often look at LUECs. You can apply LUECs to system plans as a whole, it's a bit of a stretching of the concept, but it sometimes is helpful.

But on the issue of discount rates and which discount rate you should choose, if you're an investor your discount rate is a relatively easy choice, it's the cost of your money. It's the weighted average cost of your capital, of the debt and equity that you're going to have access to. That's a simple explanation, but where do those come from? Well, cost of capital is effectively the result of three different issues: one is the time value of money or inflation, the second is opportunity cost and the third is risk. And so the weighted average cost of capital should be appropriate for the level of risk in the particular plan and the opportunity cost of all the other uses of money that you're not pursuing. But the simplified form is to simply use the weighted average cost of capital.

In the utility world, the utility rate of equity return is coupled with the cost of available debt and you arrive at the WACC. And that makes perfect sense if you're thinking about a project from the perspective of an investor because that's the return that they need to make, right? However, we're not talking about investors in this case, we're talking about cost to customers. So is the utility rate of return actually appropriate for customers? Is that the appropriate metric?

Customers are a heterogeneous group, there's all different kinds of customer classes. Even within customer classes there's a whole range of different circumstances that people have. Some customer classes will have very low costs of capital. Think of a wealthy person with high disposable income that puts a lot of their wealth in very safe investments, in bond portfolios that have relatively low returns. Their opportunity cost of money may only be a few per cent.

On the other hand, a low-income person may have to rely on credit card debt. Their cost of capital is going to be 18 per cent or higher. An extremely low-income marginal consumer is going to be relying on weekly paycheque cash loan systems that can have rates upwards of 30 per cent. So their cost of capital is going to be extremely high. So what's an appropriate cost of capital to consider for customers?

What about business customers? There's an enormous range of business customers that have different costs of capital. A venture firm that is, you know, working in the tech sector might have a cost of equity upwards of 30 per cent. For them, every dollar is burn rate, right? So their cost of capital is extremely high, as compared to, you know, a brick and mortar company that has a low cost of capital.

Out of all of that mix of that heterogeneous group of customers, it's quite likely that the average cost of capital is going to be higher than the utilities cost of capital. So it's appropriate, when you're doing analysis of this sort, to at least consider a range of cost of capitals – cost of capital, sorry. In 2010 and 2012, Nalcor used their own utility rate, and that was all, and did not consider any other cost of capital. But, at a minimum, analysis should be done that does include a higher cost of capital to represent customers.

Finally, from a government perspective, there's a different issue, which is the social discount rate. In both Canada and the United States, social discount rate has become a priority in, for example, long-term climate change analysis. If you're trying to figure out what societal policies to pursue on a problem like climate change, which spans over decades if not centuries, how do you value efforts at different points in time at different costs?

And the social discount rate is a concept that has been arrived at, which essentially turns out to be quite a low rate; actually lower than the utility rate. The most commonly used social discount rate now, in North America, is a 3 per cent real rate, plus inflation, which is typically a 2 percent and so the social discount rate would be approximately five.

Now, because the Muskrat Falls plan was such a long-term plan, it's actually also appropriate to think about it in public policy terms, and to understand, you know, how you would value the impact of the Muskrat Falls plan in public policy terms if the social discount rate of 5 per cent were used. So you end up with a range. You end up with the social discount rate, the utility WACC and the customer cost of capital as sort of a low to high range that's useful for analysis when you're talking about a multi-billion dollar project. Which inevitably, in these kinds of situations, is exactly what you are talking about.

So this analytical framework can be used to judge the decision-making process that was followed behind Muskrat Falls. Were all the steps followed? Was there sufficient data? Was the analysis deep enough to make the conclusions credible? But also, this kind of a process is the standard kind of process that should be followed. And I think it's important to point out, this is not theoretical, it's not as if this kind of a process has never been followed.

I was in fact involved in the Manitoba NFAT process a few years ago where Manitoba Hydro proposed approximately a dozen different system plan options and, you know, identified five, six different variables that were critical to that, and they ran hundreds of runs of their strategist model, or their equivalent of a strategist model. We came on the scene as an expert witness to the regulator and we took their information, supplemented by Moore, and we ran approximately 10,000 variations of our financial model to cover the different options that they presented before giving our advice to the regulator about which of the plans they should pursue.

So this is not a theoretical exercise, this is actually something that has been implemented. And it's an analytical framework that makes sense when you are talking about spending billions of dollars.

So if we then – oops, there we go – if we then take this process and step by step look back at what happened in 2010 and 2012. So the first item was to find the primary need. And the primary need at the time was to replace the Holyrood electricity generation station, which was aging and clearly it was appropriate to plan for the replacement of that station. This was the starting point for the Muskrat Falls plan and an appropriate starting point. But I think recognizing the fact that this is – the Holyrood station is a 500-megawatt fossil fuel-fired electricity generation station. That alone cannot be the justification for a $7-billion system plan, right? The two things are completely of different magnitudes.

So it can't be the only need. There, you know, were a number of other needs and other desires that had to become part of the equation. Economic development, exploiting available natural resources, improving environmental performance – there – you know, a dozen other factors quite likely played a role. The starting point for analysis was Holyrood. But, you know, there had to have been many other factors that were judged in the process, whether they were given acknowledgement or not.

The Universe of Potential Options. They did review the universe of potential options and reasonably thoroughly. On the left-hand side of this slide is the list of options that were considered. The red ones were the ones that were dismissed out of hand.

Nuclear and – nuclear because nuclear is not legally allowed in Newfoundland and not practical given unit sizes at the time. Natural gas because there's no natural gas available in Newfoundland. Coal given the fact that the federal government was already, at that point, moving to ban the use of coal within a medium-term period of time. Biomass, solar and wave because they simply are not mature enough and not practical in Newfoundland for quite accepted reasons. More controversially, imports and the isolated supply until 2041 plus Churchill Falls supply were also dismissed. What was left after all those options had been dismissed – excuse me – were oil, wind, Island hydroelectric and Labrador hydroelectric.

Not considered were a few outliers like energy storage, geothermal and solar thermal, which certainly back in 2010 were not terribly practical. There's a little bit of hindsight bias going on for even listing these, but they are more practical today than they certainly were back then.

More interestingly, there was not a lot of attention given to large-scale conservation and demand management. At the time, certainly in Ontario and particularly in British Columbia, there was a lot of activity about conservation and demand management, and it's not clear that enough attention was paid in the system plan to the possibility, for example, of converting electric heating on the Island to heat pumps or making use of geothermal heating resources. Those things can be expensive from a capital perspective but quite cheap from an operating perspective. It can improve efficiency dramatically and could have made an important difference in the system plans.

It seemed – it appeared that very light attention was paid to those possibilities, whereas at the time, in other jurisdictions, there was much more focus on them. And much more controversially, very little attention was given to the possibility of importing electricity from Quebec until 2041, and I'll get to that later in my presentation.

A moment on the isolated supply until 2041 and then Churchill Falls supply issue, which was essentially a build-transmission-later strategy. At the time, in the initial report in 2010 that went to the regulator, Nalcor argued that building – replacing Holyrood and continuing to use fossil facilities until 2041 and then building transmission in 2041 was a more expensive option. And certainly – from the perspective of oil prices at the time, it certainly looked that way.

Also, there is the fact that if you build new assets in the years proceeding 2041 – excuse me – and you likely would have to build those new assets, then when a new transmission was built in 2041, those assets would effectively be stranded, and you would have stranding costs that would have to be taken into account in the system plan. The calculations seem frankly credible. The idea of building long-lived infrastructure and then purposely stranding it halfway through the life of the assets doesn't make a whole lot of sense.

So, you know, the question is, really, do you build transmission infrastructure right away, or do you then wait for a period of time to build transmission infrastructure when you're actually going to use that transmission infrastructure to replace domestic supply? And so, you know, having reviewed the information that they provided, it does seem like a credible conclusion that the focus on oil until 2041 and then build transmission did not appear to be a practical option, always given all the other reference assumptions that were included at the time.

So, Identify Costs, Benefits, Risks & Opportunities. It does not appear that there was a holistic analysis of costs, benefits, risks and opportunities provided to compare and contrast the plans. In 2010, it's clear why: the process before the regulator in 2010 was deliberately limited solely to the question of consumer costs. So they – the analysis of costs, benefits, risks and opportunities typically goes well outside that scope and would consider different – excuse me – different stakeholders, and that was not in scope in the 2010 process.

The – arguably, understanding and analyzing the risks and opportunities for ratepayers could have been done in greater detail, but it just did not appear in the record. There was some analysis, obviously, of costs and benefits and risks as you go through all of the materials, but it's in a piecemeal fashion and never really brought together in a single comparative analysis: Here are the costs and benefits and risks and opportunities of system plan A, and here are the costs, benefits, risks and opportunities of B. Here's how they compare and contrast and why we think one is potentially superior to the other.

Moreover, there were elements that were just never addressed, and the most glaring one is the impact of each of those system plans on Churchill Falls post-2041, which we'll talk about in greater detail a little bit later. There was attention, obviously, paid to Churchill Falls as an option – there was a paper that was released in 2012 that talks about whether it would make sense to wait for 2041, and for a range of reasons, that was deemed to be not a good step to take – but not an explicit recognition that the choice of system plans would have an impact on the value to Newfoundland of the Churchill Falls Generating Station.

Prepare financial models for the available options – this was obviously done for the Interconnected Island and the Isolated Island models. In the Interconnected Island plan, to be blunt, was basically the Muskrat Falls plan as negotiated plus some other stuff in the future, right? To put it in glib terms, there were a series of small investments that would occur starting about 20 years in the future largely for combustion turbines that would be used for capacity – peak capacity management. But the vast majority of energy – incremental energy for the Island would be coming from the Muskrat Falls generating station for 50 years.

The Isolated Island plan, on the other hand, was an assemblage of disparate assets, a mix of new oil-fired turbines, Island hydroelectric opportunities, as well as wind assets. And that assemblage was calculated based on the

Strategist program. And deliberately calculated in order to be the cheapest possible assemblage of such assets for the Island. And I think it's fair to say that based on the assumptions loaded into the Strategist program – the Strategist program will do what you ask it to do, which is spit out the cheapest version of the plan.

And so by definition, what you end up with is that the Isolated Island plan is the cheapest possible Isolated Island plan or the cheapest possible alternative to the Interconnected Island plan. And so, going back to the idea of fairness and the fairness test where you have to look at options as they compare to the cheapest viable alternative, while the cheapest viable alternative to the Interconnected Island plan is the Isolated Island plan because Strategist says so, effectively.

But the Interconnected Island plan financial model is actually three models. There is the PPA model, a very large, very complex iterative model prepared by PricewaterhouseCoopers, which calculates a 50-year inflation escalating contract price for a fixed take-or-pay energy contract, which also captures within it the cost of the Labrador Transmission Assets.

Second, there is a transmission tariff model for the Labrador-Island Link which is a cost-of-service model, not a PPA model. And cost-of-service models have a very different economic outcomes for ratepayers than PPA models. So whereas the PPA model was, you know, starting at a base price and a rising within two per cent inflation every year, the cost-of-service model actually starts with a much higher tariff that declines over time.

And that's simply because cost-of-service construct – economic construct – pays investors for all of the equity and debt that is in a project at any given point in time. And over time in a cost-of-service model as equity and debt principal are paid back, there is a return of capital both for equity and debt. Therefore, there's less equity and debt principal in the project over time and costs go down over time.

So two different models. And then both of those models – the outputs of both of those models were then put into a cumulative present worth model which itself also included all of the other assets that were to be included in the Interconnected Island plan in the future. And so, any scenario planning, any analysis would've required working through all three of those models in order to come up to achieve outputs for the Interconnected Island plan.

For the Isolated Island plan it's a simple cumulative present worth model. It's a single model. But it's a single model that comes out of the Strategist model. So it – the outputs from the Strategist model were then put into a financial model which is a CPW model. It's important to note that neither of these was a comprehensive system plan, right? There are many electricity assets on the Island of Newfoundland that were not included in any of these models.

There are existing Island hydroelectric facilities that are simply assumed to run forever, right? There are some other assets on the Island of Newfoundland that were expected to continue to run for a large period of time that were not included in either of these models. The models were incremental models only. And they were identified through Strategists as being the required increments based on the assumptions that were included in the Strategist model.

So when you look at the Island of Newfoundland back in 2010 on the total consumption of the Island it's a – you know, it was around eight terawatt hours a year. In the first year of the Interconnected Island plan, the Interconnected Island plan is only delivering two terawatt hours. It's only delivering 25 per cent of the total consumption of the Island. So it's not a system model; it's just an incremental model.

It's the portion of the Island supply that that model is going to cover, right? Which makes it a little bit difficult to compare these two plans, for example, on a LUEC basis because each of the two plans is providing different amounts of power to the Island. And, therefore, the other assets on the Island are producing different amounts of power themselves at different prices.

You can – and at – back in 2010, Nalcor did calculate entire system prices, but you need access to the full model for the entire system in order to do that – which Nalcor has. But I just – it's important to pause here and talk about what exactly we're talking about when we're comparing these two system plans.

There were no models of ancillary or strategic impacts. In the 2010 process, because the focus was on customer costs, there simply was no time or attention paid to taxes or economic development impacts, First Nations impacts. I mean, all of those things were out of scope.

In 2012, some of the internal government documents that have been made available do show, in fact, there was attention paid to those issues. There was some rudimentary financial modelling of economic, you know, multiplier effects from jobs and so on and so forth.

But what's not clear is how any of those things were integrated into the decision-making process. Was there a point-scoring system? If one option produces more jobs, does it get 10 points versus zero points for the other option? If one option delivers slightly better environmental outcomes, was there some points given for that? How were those ancillary benefits included in the decision-making process – there doesn't appear to have been an explicit model for how to take those things into account.

And, again, no evidence of modelling to address the issue of Churchill Falls, either in terms of impact on taxpayers or in terms of impact on ratepayers if there is a potential impact.

The next stage is to perform sensitivities on the models. There were sensitivities that were prepared, more sensitivities in 2010 than in 2012. There were some sensitivities on cost overruns in the project. In 2010, there were sensitivities tested on domestic load and those sensitivities were tested at the insistence of the regulator and intervenors; they were not initially offered up by Nalcor.

There were sensitivities that were calculated on fuel prices at both stages. There were external firms that were asked to provide fuel price projections – PIRA, principally, and they – the PIRA fuel-price projections were then reviewed by others. But those projections were tested.

Interest rates were tested, but, for example, export prices were not tested nor were there changes to expectations tested around equity prices or inflation rates or schedule delays in the project, which is a particular issue that we'll talk about more in a minute. Nor was there any time or attention given to the potential impact of technology progress, and that's a particularly important one because there's a stark contrast between the two options that were being modelled.

Well, actually, we'll – I think it's probably best – in a couple slides we'll get to that issue.

Scenario testing was simply not done. The closest thing to scenario testing was in the 2010 process. Intervenors and the regulator asked for some combinations of fuel prices and load to be tested. In 2012, there's no evidence of any modelling that was provided to me, in any case, on the record, that there were scenarios tested. That's particularly egregious because the limited modelling of load plus fuel scenarios in the 2010 process did throw up some significant questions about how each of the different options would fare in those scenarios.

The analysis appeared to be based on the reference scenario and a small number of sensitivities only. And again, it's fair, you know, in making this critique and making this criticism, I don't think I'm holding Nalcor up to a standard that is unreasonable. Manitoba Hydro literally worked on hundreds – actually, I think, to be fair, by the end, over 1,000 scenarios that they tested and they ran their model for.

It's possible to do these things. It's reasonable to do these things when you're talking about multibillion-dollar expenditures. It's in fact unreasonable to not do them.

And so, I do call it a critical failure of the process because, had they performed this analysis, they then would have had to defend why one option was still superior than the other option despite what might happen in certain scenarios. They would have to defend perhaps that they didn't believe the probability was very high or that, on balance of probabilities, more scenarios were in favour of one option than the other option or what have you. But in the end, without analyzing scenarios, it was simply too easy to say that the chosen plan was superior to the other plan. In all of the sensitivities that they ran, the individual sensitivities, the chosen plan came out on top, but that simply didn't include the scenarios that were problematic for the chosen plan.

There we go.

And, finally, make a judgment. The regulator's conclusion in 2010 was that there was too much uncertainty to conclude that one plan is actually lower cost than the other. And to be fair, it's potentially a disrespectful conclusion to say that this was an abdication of responsibility because there was a poverty of analysis provided to the regulator, but it was an abdication of responsibility. I mean, these decisions are always difficult and there are always judgments and they always involve a massive amount of grey area, and it doesn't mean you can simply not decide, right?

The Holyrood plant needed to be replaced. There needed to be a system planned to replace it. You need to come to a decision, and the decision is never gonna be perfect and it's never gonna be certain, but you still have to come to a decision.

In 2012, the government did come to a decision, and I have the quote there from the minister on the day of the announcement, that Muskrat Falls will meet the province's future energy needs, critically, "stabilize rates for residents and businesses, while generating significant economic, employment, and social benefits for the people of our province …." And that goes back to my point about the drivers for the project.

Very clearly, the government was considering things other than costs. In their announcements and in their statements, they reiterate that over and over again. But the analysis, on its face, doesn't appear to support the conclusion that the government came to. It's very difficult, looking at the evidence, to go from the evidence to this conclusion, right? And that may simply be because the evidence wasn't shared, but I think this Inquiry has done a good job of surfacing available evidence and material that was there, or perhaps simply because the work wasn't done.

So, now I'd like to turn to a couple of the big issues that were left off the table. First is the Quebec option. So, the Quebec option was the idea to import power from Hydro-Québec from approximately 2015 until 2041 – this is thinking back to the 2010, the first process – and then after 2041, full power to be supply from Churchill Falls.

And so, this option would have been to build effectively the Labrador-Island Link, but not build the Muskrat Falls generating station or the Maritime Link. There would be no route to US markets except through Quebec and you'd have effectively a firm-power contract with Hydro-Québec for approximately 25 years. And that firm-power contract could have looked something like the PPA with the Muskrat Falls generating station, except for 25 years instead of 50 years, and paid to Hydro-Québec as opposed to being a Nalcor project.

The option was not seriously addressed. There was – it was not included as one of the options in the initial documentation that was sent to the regulator in 2010. It came up as a question from an intervenor in the – in the regulatory process. And the relatively brief response was that the assumption was that the price of power from Quebec would be the same as the price of power from New York or New England, which had been reviewed in the materials. And since those prices were assumed to be high, the option was not pursued any further.

Now, in the documentation about importing power from New York or New England – one of the critical weaknesses of an import plan was the fact that it was not possible to get 25 years of firm power from New York or New England, just because of the way the transmission systems are regulated in those jurisdictions.

However, Quebec could provide firm power and so that difference was not acknowledged at all. So it ensured this option was rejected and simply not pursued. So, it's – it's worthwhile to ask would it have been possible – was it a practical possibility?

So, what's on this slide is the amount of power sold by Hydro-Québec from 2003 to 2018 – those are the blue columns. The left scale is gigawatt hours and you can see that from 2003 onwards – Hydro-Québec has been exporting 15,000 gigawatt hours or more on an annual basis. And the orange line is the average annual price – selling price – for their power.

The – now this, to be fair, is not net exports. This is their gross exports. So, this includes their trading activity. Net exports would be a slightly lower number. Net exports have not been less than 10,000 gigawatt hours a year since 2003 for Hydro-Québec.

The total deliveries from the Muskrat Falls Generating Station to the Island of Newfoundland are scheduled to go from 2000 gigawatt hours to 5000 gigawatt hours over the course of 50 years and so would the power have potentially been available from Hydro-Québec? Yes.

And this – this graph doesn't – this graphic does not take into account the 1550 megawatts of additional power from the Romaine Complex that Hydro-Québec started building in 2008 and is going to be finished in about 2022 – the last piece of it. The last couple of years – 2017 and 2018 – would include a little bit of Romaine power because a couple of the Romaine facilities have opened. Hydro-Québec has lots of power and, in fact, has been trying to find ways to sell it and sell more of it.

So, was it available? Yes, it was available. But you can also see on that price line that – in the period from 2008 to – sorry from 2003 to 2008 – the price of this power was quite high. It was in the $80-90 per megawatt hour range. Now, it started to drop after 2008. And, so, in 2010, when the regulatory process was going on, the price there – Hydro-Québec's average realized price was over $60. So, less than it was before, but still reasonably high.

The – and the interesting thing, of course, was at that time, we were going through the Great Recession. And so, there was a perception, that was common at that time, that the decline in prices had a lot to do with the Recession. And there was the possibility, or frankly, probability that prices would rebound after the effects of the Recession were over.

In reality, that rebound never came. Prices, in fact, have gone down into the 40s. You can see the realized price for Hydro-Québec power has been in the mid to low 40s for a number of years. And the reason is, there has been a structural change in electricity markets because of the low cost of natural gas, and the increasing prominence of natural gas power in the Northeastern United States.

So, prices are fundamentally different now than they were in the early 2000s, but that was not necessarily apparent in 2010, or even in 2012. I think it's – we have to be very cautious – and I'm going to talk about this a little bit more in a few minutes – we have to cautious of allowing our biases from today to affect how we judge things that – you know, decisions that were taken in the past. From the perspective of 2010, it was not at all apparent that export prices were going to be collapsing, right?

So, the perception in 2010 that a contract with Hydro-Québec would be expensive is actually not at all unreasonable. Another element to that is, that Hydro-Québec's – just to come back here to this slide – Hydro-Quebec's realized prices are a combination of their firm power and surplus power sales. You know, they sell firm power to certain customers at relatively high prices, and then they sell surplus power on the spot market at whatever price they can get.

And so what you see here is simply the average realized price. So, the firm price is going to be substantially higher than the average realized price, and the spot price will be substantially lower. So going back to that 2010 period and saying: Well, what would be the firm price for power from Quebec for a 25-year contract? Well, quite likely, that would be quite high.

It would be not unreasonable for that price to be pegged at what was thought to be a long-term gas power price. And if you think about the way a gas power plant – a new gas power – gas-fired electricity generation plant is priced, back in 2010 the LUEC on that kind of a plant would have been eight or nine cents, or $80 or $90 a megawatt hour. And so for Hydro-Québec to say – well, for Nalcor to say we would expect that Hydro-Québec would charge us a price of that sort is probably not unrealistic.

So – but, beyond that, is it even reasonable to believe that there would have been a normal, quote unquote, commercial discussion between Nalcor and Hydro-Québec about a 25-year firm power contract in 2010. We have to bear in mind that already twice in the preceding decade Nalcor had taken various Québec organizations to court for rejecting transmission access applications. And then in 2010, a lawsuit was launched in Quebec's superior court over Churchill Falls. Three court cases in less than five years.

How could there be a reasonable expectation that Nalcor would then turn around and have an amicable commercial discussion with Hydro-Québec about a firm power contract? It just doesn't bear scrutiny. If you're Hydro-Québec, you would say, sure, let's have a discussion about a firm power contract but, in the meantime, you drop all of your lawsuits and let's sort out this silliness around Churchill Falls. You know, you cannot have one without the other. The two become inextricably linked.

So, you know, the – I think that – in fairness to Nalcor, they were dismissive of the intervenor question in 2010, and they were dismissive with some justification because it was simply not a practical option, given everything else that was going on.

But that does lead directly to this question of Churchill Falls, which I wanted to spend some time on.

This is the issue that was not discussed in most of the information provided in 2010 and 2012. It was not highlighted as a reason to pursue the Muskrat Falls Project; no analysis of the potential impact of the Muskrat Falls Project on the future value of Churchill Falls was provided.

There's clearly a difficult history surrounding Churchill Falls, and the resulting relationship as between Newfoundland and Quebec, between Nalcor and Hydro-Québec. And that history hovers over the Muskrat Falls Project, but it's not made explicit anywhere. There is that old saw that generals fight the last war, and it is difficult to separate, you know, rational commercial calculation from emotional proclivities, right?

The idea of doing another, quote unquote, contract with Hydro-Québec, given how poorly the Churchill Falls contract turned out for Newfoundland and for Nalcor, would have been outlandish, right? And the repeated legal actions related to Churchill Falls were that ever present backdrop.

So, the Churchill Falls contract expires in 2041. At that point, the generating station will be 70 years old, which, for most kinds of infrastructure, is a big deal. Very few pieces of infrastructure or infrastructure assets last longer than that. But the reality is hydroelectric dams are peculiar in that way. They are, in effect, amongst the longest lived infrastructure assets in the world. Only ports, really, have lasted longer.

There are facilities operating today in Canada that are coming up to their 100th birthday and they're still fine and they're expected to continue to produce power for quite some time. As long as the civil infrastructure, the actual dam itself, does not suffer some sort of catastrophic failure, you can just replace turbines, you can re-spin generators, you can replace pumps, you can replace valves and the facility will just keep on going.

So at 70 years old, the Churchill Falls Generating Station will be fully depreciated, will have no debt to repay – already has no debt to repay, and can simply keep on going. The facility is 65.8 per cent owned by Nalcor and 34.2 per cent owned by Hydro-Québec, which is a critical and salient point. The current operating costs, the facility is under $3 a megawatt hour. It is 5,428 megawatts in the stated peak generating capacity, and produces somewhere between 30 and 35 terawatt hours of power a year – of energy, sorry, a year, which is about a 60, 65 per cent capacity factor.

It's the third largest hydroelectric facility in North America by rated capacity. It is a spectacular asset and extremely valuable. Notably it is, you know, six times the size of the Muskrat Falls generating station that's now under construction, which is why it's such an important strategic consideration.

Moreover, it has enormous storage capacity, water storage capacity and flexibility in operation, which is a second major value driver, besides the fact that it can produce gobs of cheap power, is that it can be timed. So, for example if you want to provide affirming service to someone, to another electricity system that has variable power like, oh, wind farms or solar farms, then a hydro facility with storage capacity is perfect for that service. Hydro-Québec likes to call itself the battery of North America because their entire hydroelectric system has been designed for water storage purposes. It's one of the greatest values that they have.

And other than – I mean, not only does Hydro-Québec produce cheap power because it's all hydroelectric, but they do have that flexibility. And that flexibility is actually going to become more valuable in the market as we go forward, because wind power is inherently intermittent and solar power is inherently intermittent and, as jurisdictions across North America build more wind and more solar, they're going to need more storage and more flexibility.

And that storage and flexibility could theoretically come from batteries and, in fact, may come, depending on how battery technology develops over the next 20 years, on a local level could from battery technology; but the storage resources that are available in Quebec, in Manitoba, in British Columbia and at Churchill Falls is also going to be very valuable, assuming that storage capacity has easy access to market and the transmission system that's necessary to support it.

So Churchill Falls is currently a valuable asset, simply because it produces power at under $3 a megawatt, but it also is valuable and is going to continue to be valuable because of its storage capability.

So what are the options for the future, in 2041, when the existing contract expires? Well, one option is a new sale contract with Hydro-Québec negotiated on some terms and conditions. A second option would be an agreement with Hydro-Québec for transmission access to export markets. A third option would be a subsea-transmission route to export markets. Two other options, which I would argue are simply unthinkable, are to build local industry in Newfoundland and Labrador sufficient to consume the power that comes out of the facility, and finally, to mothball the facility.

So the reason those things are unthinkable. So 30- to 35-terawatt hours represents a constant consumption of 3,500 megawatts of electricity, day in, day out, 365 days a year, 24 hours a day. The city of Toronto – with three million people, with countless buildings, air conditioners, lights, machines, computers and all the rest of it – consumes approximately 5,000 megawatts at peak, and substantially less than that on a baseload basis. So you cannot go from not consuming to consuming 30- to 35-terawatt hours just like that.

You could theoretically build a series of aluminum smelters to use that power, but even then you'd be talking about billions of dollars of aluminum smelters or data farms or whatever other kind of large energy consumer that you can think of. But the idea of building sufficient industrial capacity to use that 35-terawatt hours is simply not practical. So it has to be exported somewhere. And the idea of mothballing a facility that, even at that point, will still be worth $20 to $30 billion is also unthinkable. So the power will have to get out to market.

And so those three options – sale contract with Hydro-Québec, agreement with Hydro-Québec for transmission service and subsea transmission – are really the only options. And I would actually argue that the first two really are the same thing. The first two are a negotiation with Hydro-Québec. Whether that negotiation results in a sale contract or a transmission-access contract, it's just a negotiation. Those two things are almost fungible. Nalcor already had the experience of requesting and being denied transmission access through Quebec to reach export markets.

I don't foresee a future negotiation to be any different. It will be a real commercial negotiation or not. But I don't think there is any reasonable future in which a transmission route through Quebec is achieved against Quebec's wishes. Despite the fact that Quebec is a signatory to all FERC rules and has agreed to open-access tariff rules and so on and so forth, a transmission-access route through Quebec will only be realized by a commercial solution with Hydro-Québec and the Province of Quebec.

So negotiate or build an alternative transmission route. So what does that look like? Well, the Muskrat Falls plan actually shows the way. Currently the Labrador-Island Link brings power from – will bring power from Muskrat Falls to

Bottom Brook at a cost of about 4.5 per cent transmission loss. And then power will go from Bottom Brook, Newfoundland, to Woodbine in Nova Scotia for another 4.8 per cent transmission loss, and then power could go through the existing AC system in Nova Scotia to get to the New Brunswick boarder at a 4 to 5 per cent transmission loss, and then through New Brunswick to get to Maine at another 3 to 5 per cent transmission loss; all together, 17 to 18 per cent of transmission losses, plus tariffs along the way.

Now, if you were going to build a new facility, a new – it would be a hundred per cent DC transmission line. You wouldn't build it in pieces. You wouldn't go through existing AC networks and switching in Newfoundland and Nova Scotia and New Brunswick. You would likely build two or three segments with repeaters of a full DC line to get all the way down into Massachusetts where the customers are.

What would that cost? Honestly, I have no idea. The – you know, you'd have to scope out potential routes, there would have to be negotiations with Nova Scotia if you were going to be crossing over land in Nova Scotia, which would likely be cheaper than continuing the whole thing under water, there would be issues about sea lanes and all the rest of it. But the Muskrat Falls plan and the work done for Muskrat Falls shows what can be done and, you know, a path for how to get there.

And a dedicated DC transmission line would be more efficient than the assemblage of DC and AC that was prepared for Muskrat Falls. Probably you'd still have 10 to 15 per cent losses in the end just given the massive distances, but less than the 18 per cent that's already there with the different pieces in the Muskrat Falls plan. The alternative is to go through Quebec.

Quebec already has a high-voltage system that leads from Churchill Falls and connects into Vermont and New York. The losses are about 5 per cent on that network. In 2041, those transmission lines will be old and will require reinvestment and I'm sure Hydro-Québec will probably say, well, no, we can't, you know, offer you tariffed service because we're going to have to rebuild all these things.

And so we need to have an agreement and, you know, we may want to rebuild them for other purposes. We may want to build new facilities of our own that are going to use up this capacity. Hydro-Québec, of course, has first right on all transmission capacity inside Quebec. They will find reasons to make the negotiation difficult. That's the reasonable thing to do.

If I were giving Hydro-Québec advice on how to commercially negotiate, it would be to come up with reasons to make it difficult. They are tough bargainers. So this is a purely illustrative example of what these three options might be. Now, if this negotiation were happening not for 2041, but were happening for 2021 – if they were happening today effectively, using today's costs and prices, what would it look like?

So let's assume 35 terawatt hours of output from Churchill Falls. And let's assume costs of operation at Churchill Falls of $95 million a year, which is $2.75 a megawatt hour. Transmission losses through Quebec would be 5 per cent, that's the middle column. Transmission losses through a theoretical new subsea route would be 15 per cent. I did some back-of-a-napkin calculations and I assumed a subsea route would cost $10 billion to construct: $4 billion of equity, $6 billion of debt at approximately an 8.5 to 9 per cent whack on a 50-year PPA because this is not a transmission utility; this is a piece of transmission infrastructure used solely to get power to market. So it would be a merchant transmission line, but that PPA would include profit for the owners and builders of the transmission facility.

And so the annual transmission tariff on that subsea route would be something on the order of $700 million a year. Alternatively, if we looked at Quebec and we look at the fact that currently Nalcor has a transmission agreement with Quebec for 265 megawatts of transmission capacity at approximately $20 million a year transmission tariff, so if that were simply scaled up – let's pretend for a moment that Quebec was willing to scale that up to be for 5,000 megawatts, it would be about $400 million a year. And I'm presuming that that $400 million a year will include a couple hundred of million dollars of profit on Hydro-Québec's equity in the project. If the realized price at export markets was in the range of $40 to $60 a megawatt hour – which is in fact what Hydro-Québec's realized export price is right now, between $40 and $60 – then CF(L)Co's profit could be estimated in each of these three different scenarios.

So sticking to the right column first, the subsea route, you produce 35 terawatt hours of power, you have a little less than a hundred-million dollars of local costs, you lose 15 per cent of that power in transmission losses and you pay a $700-million tariff and you generate between $40 and $60 a megawatt hour for all the megawatt hours that actually reach market, right, so 15 per cent less than your 35 terawatt hours. CF(L)Co's operating profit at that point is somewhere between $400 million and a billion dollars a year, entirely dependent on what the market price is. But Nalcor's profit is 65 per cent, because that's what its ownership in CF(L)Co is – 65 per cent of that amount plus the profit on the transmission service that is provided. So Nalcor gets their 65 per cent from that 400 to a billion, plus approximately $300 to $350 million of profit built into the transmission tariff.

And so Nalcor would be making somewhere between call it 550 and a billion dollars a year under that subsea route, but has invested $4 billion in a transmission line. So that 600 to a billion dollars in profit is at least partly in compensation for having invested $4 billion in a transmission line, right, and there's also $6 billion of debt out there that has to be managed as well.

On the other hand, if Quebec were willing to provide transmission service, which is the middle column – same kind of calculation, 35 terawatt hours, only 5 per cent of losses and $400 million of tariff, the same $40 to $60 a megawatt hour – then CF(L)Co's operating profit would be substantially higher. It's the difference in the transmission tariff, essentially.

But it's the transmission tariff plus the fact that you're not losing that extra power. So you're only losing 5 per cent instead of 15 per cent of your power before it gets to market. And so CF(L)Co's operating profit would be between 800 and $1.5 billion, which suspiciously looks like Hydro-Québec's current profit on the power that comes out of Churchill Falls.

The operating profit – sorry, I'll skip over the operating profit for a second. Nalcor's share would be 65 per cent of that; Hydro-Québec's share would be 34 per cent of that. But Hydro-Québec would also be making some money because they are providing a transmission service and they're putting up the money to rebuild and maintain the transmission network. But Nalcor's profit, at the end of the day, is still between 550 and a billion – fairly similar. The Nalcor profit, in the middle column and in the right-hand column, they're not too far from each other, except in the middle column, Nalcor is not putting up $4 billion to build a new transmission line.

So, arguably, the middle column is the optimal outcome for Nalcor – put up no money and get almost the same profit, right? But for Hydro-Québec, they're putting up money to maintain – to rebuild and maintain their transmission system. And, yes, they're making more money but they're not making substantially more money.

Hydro-Québec, on the other hand, would prefer a different thing, which is the first column. They would like to simply renew the contract that they have today. Today, their contract is for $2 a megawatt hour; $2 a megawatt hour is essentially the cost of production at Churchill Falls. Now obviously, Newfoundland and Nalcor are not likely to agree for – to a renewal at $2 megawatt hour. If there was no subsea route, if there was no subsea alternative, however, how would you justify anything else?

The subsea route is the best alternative to a negotiated solution with Hydro-Québec; it's a BATNA, is the language of mergers and acquisitions. You always have to have an alternative; if you have alternative, what leverage do you have in negotiations? The fact that the Muskrat Falls plan has shown the way, has shown a route in terms of how to build a transmission line that reaches export markets, has created the BATNA.

There has been a lot written about the 1971 contract for Churchill Falls about how Newfoundland was backed into a corner and agreed to a contract that was punitive. But at the time, what was the real alternative to a contract with Hydro-Québec?

Today, we know what the real alternative is. The real contract – the real alternative is a new subsea transmission route. In 1970 or 1965, was that subsea transmission route an actual practical possibility? It wasn't deemed to be at the time. And a critical issue in considering Muskrat Falls is: if Muskrat Falls had not been pursued, would that subsea route be creditable today? It is very easy for us to believe that the subsea transmission route is a practical possibility today because the Maritime Link has been built; the Labrador-Island Link has been built; we know they can be built.

All of the geotechnical work was done to show, you know, exactly where lines should be dropped in the Straits of Belle Isle so the icebergs won't rip it apart. But that work wasn't done in 1965 or 1970; it's only been done – it was only done, you know, recently. And even then, you know, by the time there's a negotiation related to Churchill Falls there will have been years of performance of the Muskrat Falls infrastructure of the transmission lines to demonstrate that that infrastructure will last and is a practical alternative to a deal with Hydro-Québec.

So, the fact that Hydro-Québec would like to just renew its contract at some low price, the alternative to that really only is the fact that a transmission line is possible. And because a subsea transmission line is possible, is the best alternative, then you can have a real negotiation. Because why would Nalcor agree to any deal that had Nalcor profits being less than $500 million a year, if that's what Nalcor could do with a subsea transmission route, right?

If you look at what I've done with the first column, because I've said, well, what if Quebec comes back and offers a price that is equal to the net-realized price of the subsea transmission route at Churchill for CF(L)Co? In other words, if Hydro-Québec offered a price of $14 to $31 a megawatt hour with no transmission loss at the border, that would generate operating profit for CF(L)Co of $395 to $990, which is identical to the CF(L)Co profit under the subsea route, right? Then, Hydro-Québec would be providing their transmission service internally and they would make the arbitrage at the border to export markets.

Hydro-Québec, in that scenario, makes a lot more money and Nalcor's profit drops to the $250 to $650 range. That would be Hydro-Québec's preferred world, right? That's not going to be Nalcor's preferred world. Nalcor's preferred world is not going to be go from a $2 contract to a $14 contract. Nalcor's preferred world is going to be to go from a $2 contract to something pegged to the market price with a reasonable compensation for the transmission service provided.

And so the reality will be that, in the end, a rational commercial negotiation is going to end up being somewhere between all of these three columns. It will be some form of a contract that says: Either you give us a reasonable price or we build the subsea transmission route. We don't really – we, Newfoundland, don't really want to spend $10 million on a new subsea long-distance transmission route if we don't have to, but we will if you're unreasonable, right? And that is possible now because of Muskrat Falls, and that has to be taken into account when judging the Muskrat Falls plant.

But it wasn't, at least not publicly. You know, this kind of analysis doesn't appear anywhere. And yet it must have been relevant. It's so obvious and so large in magnitude that it must have been relevant. But it doesn't appear in the record.

One final point, and that has to do with ratepayers versus taxpayers and the Newfoundland government.

MR. COLLINS: Commissioner, I wonder if this is a good time to take the morning break?

THE COMMISSIONER: Yes. Okay. Is this –?

MR. COLLINS: (Inaudible.)

THE COMMISSIONER: – a good spot to break or –

MR. COLAIACOVO: I'll just finish this – if I could just finish this one last –

THE COMMISSIONER: – (inaudible). Sure. Okay.

MR. COLAIACOVO: – item on – 'cause that's the end of the section. The chart here, one of the lines on this is the effective price at Churchill. So where the export market price is assumed to be $40 to $60, the effective price at Churchill, you know, is a discount to that – $26 to $29 discount. And the only point here is that, theoretically, CF(L)Co should be indifferent to selling power at either the effective price at Churchill, the $14 to $30 or $40 to $60 in the export markets, which means the domestic price, if you will – the domestically available price will be that lower number, the 14 to 30. Everything above that price is profit.

So, for example, in a future, post-2041 environment, there is every reason to believe that Nalcor could use some of the power from Churchill Falls to supply domestic requirements in Newfoundland. And what would the price for that power be? Well, it would be $14 to $31, right? Which is the effective alternative to exports plus whatever markup Nalcor chooses to place on it. Right? Moreover, even at that price, Nalcor is making profit, because they're making their 65 per cent share of the CF(L)Co profit, which means that profit margin, you know – at the moment the assumption is that entire profit margin goes to taxpayers.

There is no commitment anywhere that any of that profit margin from Churchill Falls should go to ratepayers. Certainly there was – that indication was never made as part of the Muskrat Falls plan. Right? So all of that profit margin accrues to taxpayers. And yet, you know, my argument is the Muskrat Falls plan has created the best alternative for the Churchill Falls in a subsea transmission route.

Ratepayers are paying for the Muskrat Falls plan, and yet they are not included, at least in terms of the four corners of the plan, in terms of eligibility to receive some of that benefit that was created. And, it is potentially a substantial number.

And that was it for that section, so …

THE COMMISSIONER: All right.

So we'll take 10 minutes here, then, for a break.

CLERK: All rise.

Recess

CLERK: All rise.

Please be seated.

THE COMMISSIONER: All right, you can continue now, Sir.

MR. COLAIACOVO: This next section –

THE COMMISSIONER: Is your microphone on there?

MR. COLAIACOVO: (Inaudible.)

This next section is called The Challenge of Retrospective Judgements.

It's about looking back at the decision that was taken and – if we followed a fairness-opinion model – what do I think might have been concluded at the time. But, I think it's – so, the process in 2010 and 2012 was incomplete. There, you know, were lacking Strategist runs, there was analysis of worst case scenarios that was missing, analysis of possible mitigation options was missing, no clarity on the likelihood or probabilities of any scenarios. I mean, there's – there was a lot of work that should have been in the record that was not in the record.

But having said that, looking back and trying, today, to think about, well, if the work had been done, what kind of a decision might have been possible is incredibly difficult just because of the bias that seven years of history creates.

We know today about delays and we know today about cost overruns. But, at the time, when the decision was taken, those were just possibilities. We know today about low fuel prices after 2014, we know about low load in Newfoundland, and export prices and so on.

But in 2010 or 2012, there was a range of future possibilities and so, trying to divorce yourself from the biases of what actually happened and put yourself in the position seven years ago of somebody trying to make a judgment is incredibly difficult and it's nearly impossible to do. But the exercise is meant only to try and illuminate what can be illuminated based on the available information that's there.

And I just – I wanna skip back to slide 7 because I glossed over it earlier about what a fairness opinion actually looks at. And a fairness opinion is the typical investment banking tool for making judgments about transactions. And the first test of a fairness opinion is that from the perspective of a shareholder: Is the proposed project or transaction at least as financially favorable as the available alternatives? And sometimes that's the only test that's required. In a simple transaction, you just look, you know, and see is the next best alternative not as financially favorable, no, done. Right?

But in many cases – as with Muskrat Falls plan, as with the Interconnected Island plan – it's much more complicated than that. You have all kinds of uncertainty, there's overlapping outcomes. In some possible futures, one option is better; in other possible futures, a different option is better. You don't know what the probabilities are for any of those possible futures to be, so you can't just say one is more financially favorable than the other in any sort of absolute sense.

In that case, you – in order to enlighten yourself further, you look at a second test which is: Given the costs, benefits, risk and opportunities arising from the project, and all the different stakeholders to the project, are the cost, benefits, risk and opportunities being proportionally distributed amongst the stakeholders? And that sense of proportion is key because every stakeholder is going to be facing the same future. Nobody knows what the future is going to be, but you're all going to face that future together.

You have to make a decision today based on an uncertain future, and you've apportioned risks and opportunities across stakeholders. Is each stakeholder taking a relatively reasonable if they – are they bearing a reasonable degree of the risks and costs in exchange for the benefits and the opportunities that they're getting? And if everyone – if that distribution appears to be reasonably proportional, then you're much more likely to find fairness of the transaction in the face of uncertainty.

On the other hand, if it's disproportional in the face of uncertainty, then you're likely to find problems with, you know – you're likely to find that judging fairness is more difficult.

So, the second test dealing with proportionality is almost a gloss on the first basic test but an important one in complex transactions. And when you're talking about something like the Muskrat Falls plan, the Interconnected Island plan, you're very much dealing in that world.

So, if we actually look at the Muskrat Falls plan and the Interconnected Island plan, as presented, this is the reference scenario that comes out of the CPW models – the cumulative present worth models – in nominal dollars.

The left-hand is the Interconnected Island plan; it's in red, and the right-hand is – in blue – is the Isolated Island plan. Again, the scales are identical. On the left side of each graphic is the gigawatt hours delivered, which is the columns, and on the right-hand side is the dollars per megawatt hour for the power delivered, and it's the line.

So, on the Interconnected Island, it's the red columns or the amount of power, and the green line is the price for each megawatt hour of power. And for the Isolated Island – on the right-hand side – it's blue columns and the red line. You can already see some things just by looking at the outputs in this way. You can see, for example, that the Isolated Island plan is actually producing more power than the Interconnected Island plan.

So, the Strategist model was used by Nalcor to calculate what would be the optimal output from these various assets given the constraints that they input into the Strategist model – the assumptions. And this was the conclusion of the Strategist model – that that much power should be produced. Which is different from the amount of power that's coming out of the Interconnected Island and the PPA. Right?

And then the price per megawatt hour – in nominal dollar terms – just falls out of the financial modelling calculations. And the prices, you can see, are actually lower in the first 15 years. The prices in the Isolated Island are lower than they are in the Interconnected Island. But then, for the 35 years after that, it flips around and the prices in the Isolated Island are much higher. Right?

Looking at it this way –instead of looking at it in cumulative present worth terms – already provides some insight into the treatment of ratepayers over time. The Isolated Island model is good for ratepayers in the near term, but bad for ratepayers on the long-term and the Interconnected Island – it's the reverse. Right? So there's an allocation of burden to ratepayers over time that's different in the two models. And that's just in nominal dollar terms.

It's also kind of striking how, in nominal dollars terms, the Isolated Island model has this curve. The curve starts to accelerate as time goes by, which is why – if you – instead of looking at it in nominal dollar terms, if you look at it in inflation-adjusted terms – and this is just a 2 per cent inflation, right, taken out of each of those curves, and this is the inflation-adjusted dollars per megawatt hour. Red is the Interconnected Island plan, blue is the Isolated Island.

You can see that in inflation-adjusted terms, in the first 15 years, customers are better-off with the Isolated Island, but then much worse-off after that because there's this significant price jump that occurs in the years between 2032 and 2037.

And the other thing that you'll note, though, is the prices in the Isolated Island are almost flat after 2037. There's that big jump, and then flat. And why is that? Well, it's because, in the models, 2 per cent inflation becomes dominant in all of them – in both models. Two per cent inflation drives almost everything after the first 20 years because – this goes back to my point about forecasts – any forecast beyond 10 or 15 years is meaningless, so every forecast just assumes 2 per cent inflation after that.

And the 2 per cent inflation, if you look at it in nominal dollars terms, looks like an increasingly steep curve over time. Take 2 per cent inflation out and suddenly the models are flat. So, all they are, really, is inflation models. That's all they are. They're real models for the first 20 years or so, and then after that, it's just inflation.

If we take another step and now look at the CPW-type calculations. So, over the course of the full life of the models, the nominal dollar, total dollars, the inflation-adjusted total dollars and then discounted at 5, 7 and 10 per cent, you can see, in the reference scenario, the Interconnected Island is superior under every one of the calculations. But it's interestingly narrowest on LUEC terms.

Why is it narrowest on LUEC terms? Well, because the Isolated Island is producing a lot more power – Isolated Island plan is producing a lot more power in the early years, and less discounting applies to the early years than in the later years. Whereas in the Interconnected Island plan, the heavier supply of power is in the future. And when you calculate a LUEC, you discount both the dollars and the power, right? But nonetheless, in the reference scenario, the Isolated Island is clearly superior – sorry, the Interconnected Island is clearly superior.

Why is the Isolated Island so problematic? What – that turning point between 2032 and 2037? Well, it turns out that that's the period in which the Holyrood station is finally taken offline. So the Isolated – excuse me – the Isolated Island plan assumed that the Holyrood station would be life-extended, and then would be slowly taken offline between 2032 and 2037 when alternatives would finally kick in. Those alternatives would be a combination of turbines and wind farms and hydroelectric facilities on the island. But the turbines that were gonna be built were no longer gonna burn number 6 fuel, they were gonna burn number 2 fuel.

And so when you actually go into the CPW models and look at the fuel prices and the fuel cost, there's an enormous differences between the price of number 6 fuel and number 2 fuel. Number 2 [sp. 6] fuel is heavy oil, it's bunker oil, it's the lowest quality, lowest grade, dirtiest oil that you can burn, right? Number 2 fuel is light diesel, which is what you would use in a combustion turbine, all right? And it's much higher quality, low sulfur, much more refined, much more expensive. And the move from number 6 to number 2 fuel is gonna have great environmental impacts; it's also gonna cost a lot more money. And hence, the big difference between 2032 costs and 2037 costs.

If Muskrat Falls was not possible, if there were no Muskrat Falls plan and Nalcor had proceeded to follow the Strategist model recommendations to do a combination of refurbishing Holyrood and life extending it, and pursuing island hydroelectric and wind, this problem would have been a reality – 10, 15 years from now. Customers would've been facing the possibility of a very big hike in costs.

What kind of steps would you have looked at? How would you mitigate this outcome? Well, one of the obvious possible mitigation solutions is to just use less power. Use less power, burn less fuel; conservation and efficiency. You would look at every conservation program that is cheaper than burning an hour's worth of fuel. And as long as the price of conservation was cheaper than the price of fuel, you would do it, right? The other option would be at the time to look at every viable technology that might be cheaper.

And because of the steady improvement in different electricity generation technologies over the past 20 years, it's probably not unreasonable to believe there would be additional improvements over the next 20 years. So would wind farms become more efficient than they were in the past? Would they become cheaper? Would combustion turbines get more efficient?

The efficiency of combustion turbines has already improved by 5 per cent over the last 25 years. Every percentage point improvement in combustion turbine efficiency means these numbers go down, right? Because combustion turbine efficiency means you burn the same amount of fuel but get more power, right? So your effective unit cost goes down.

If there was no Muskrat Falls plan, you know, and the Isolated Island plan had been followed by default, right, there would have been a range of possible ways to try and mitigate some of these costs. And so if you're doing an analysis of different options and you identify a big problem with a particular plan, one of the necessary elements in that analysis is to think about mitigation options. So is that option fatal? If you pursued the Isolated plan, would it be fatal, because it's clearly inferior.

But there are mitigation options. What you could do – there's a series of different steps that you could potentially take, probably starting with conservation, right, rather than simply assuming load to be what it is. And that kind of analysis wasn't done, but should have been done.

Nonetheless, it is important to recognize, even looking back, that the Interconnected Island Option, at the reference scenario, is clearly superior, right, and it's robust across a variety of metrics. Plus there's no need, at least at this point, to test scenarios where the Isolated plan gets even more expensive. Obviously, if fuel prices are higher, the Isolated plan gets more expensive. If load is higher, the Isolated plan gets more expensive. Any combination of higher fuel and higher load makes the Isolated Island even more inferior than it was found to be in the reference scenario.

So when you compare and contrast these plans, the Interconnected Island plan had a single dominant asset: It's the Muskrat Falls generating station and the Labrador-Island Link. The Isolated Island plan had lots of smaller assets: Wind farms, gas turbines a couple of small hydroelectric plants on the Island. The Interconnected plan has a fixed power contract, it's a take-or-pay fixed 50-year agreement. And that's going to be critical when talking about load scenarios.

Whereas the Isolated power plan you produce only what you need, when you need it, now you have fixed cost overheads that you pay regardless. But because in the Isolated plan fuel is a much larger portion of the total cost, simply by not burning you're avoiding the fuel cost. So there is a higher degree of flexibility.

In the Interconnected plan, finance rates are only relevant at the outset. And because at the time of decision-making finance rates were low, that makes the plan look particularly attractive. Whereas for the Isolated Island plan finance rates would affect all of the costs of all of the assets ever built. And because the assets are built piecemeal over time, finance rates actually are pretty important.

So if you model scenarios, for example, where interest rates return to historical averages – and those historical averages are substantially higher than interest rates today by the way – then the Isolated plan actually gets worse, right? And that's another issue that wasn't, you know, treated to any significant extent. Next is the fact that technology changes in the Interconnected plan only affect the export market, they don't really affect the plan itself.

You built this gigantic asset. You're going to use the power that comes out of the asset, regardless of technology changes because you've already sunk the capital into it. Whereas because the Isolated plan consists of small assets built piecemeal over time, if there are improvements in technology, you can choose the improved technology.

If wind farms suddenly become cheaper than combustion turbines, build wind turbines, right? If solar panels actually became cost effective in Newfoundland, buy solar panels, but if they're not, then don't, right? That technology flexibility is inherent in component-style plans versus large infrastructure plans.

Fuel costs are largely irrelevant to the Interconnected plan, but a major determinant in the Isolated Island plan. Low load is a critical problem for the Interconnected plan because of the take-or-pay contract. Whereas high load increases the cost of the Isolated Island plan because you're burning more fuel.

Finally, the Interconnected plan, because the nature of the plan is it's a large infrastructure project, has the inherent risk and inherent weakness of large infrastructure plan cost overruns and schedule overruns. That's not a feature that you would worry about in the Isolated Island plan. Gas turbines or oil-fired diesel turbines, there are a hundred thousand gensets around the world; they're a mass produced, manufactured project, right? Wind turbines are being produced in the thousands. Those kinds of options are standard units that you buy off the shelf.

The Muskrat Falls plan is a bespoke infrastructure project. It's a one-time-only event, and one-time-only events have a long history of bad outcomes. Not necessarily bad outcomes; sometimes they work just fine. But the exposure and the risk of cost overruns and schedule overruns is always real when you're dealing with a one-time-only infrastructure project.

In my written report, I pointed out that there was a World Commission on Dams study, which came out in the year 2000, publicly available, widely reviewed, concluded based on the dataset available to them at the time that 50 per cent of all dam projects in the post-World War 2 era went over budget and behind schedule. The average cost overrun was approximately 25 per cent, though the peak cost overrun was more like 100 per cent. The average schedule overrun was two years for the 50 per cent of projects that went past their schedule. So none of this was secret, right?

And then, if you go outside of dam projects and you look at airports or nuclear power plants or bridges, there are, you know, innumerable cases of large infrastructure projects that go over budget and behind schedule. Some don't. Every company, every government that seeks to build a large infrastructure project wants to make it happen on time and on budget, but the sad reality is it often doesn't happen. And so when you're making a judgment, when you're doing a modelling exercise, you have to take that possibility into account because it's a significant possibility for a bespoke, one-time major infrastructure project.

So there's a distinct limitation in trying to test some scenarios and that is we don't have Strategist runs. We don't have access today to repeating Strategist model runs from the past. There's only the available – you know, the data that was available in the record of the decision-making process. So we can't just sort of concoct scenarios and say, and what would be the outcome of this scenario?

Financial models only have so much flexibility. You can play with fuel prices and export prices and even construction cost overruns for assets in a financial model because those kinds of changes only affect dollars; they don't affect upgrading issues; they don't change the timing of assets. But if you change load assumptions or technology performance assumptions or construction schedules, then you're actually making changes that can only properly be understood through a Strategist model. You can try workarounds, you know, by hook and crook to get some sense of what the impacts might have been, but it's an imperfect instrument that can only really be directional.

And so all of my comments from this point forward have to be understood in that light. They're suggestive only.

So, having said that, if we look at some variants around the Isolated Island plan, if rather than reference load, you look at a low fuel cost, you can see that the lower fuel cost starts to bring down all the cumulative present costs and bring down the LUEC of the Isolated Island plan. As you would expect, because if fuel is 37 per cent cheaper, then the power is going to be cheaper. It wont be 37 per cent cheaper, because you still have the same fixed overhead costs, but you're burning – you know, you're – the price of fuel is 37 per cent less, so your total costs are going to be a significant per cent less.

If you have a lower load, then you're not only burning cheaper fuel, you're burning less fuel. Now the problem with lower load though is – recall that the Isolated Island plan assumed that you would build facilities piecemeal over time. Every few years you're building another – either another turbine or a wind farm or a hydroelectric plant. If you have lower load, the timing of that construction would not be the same. You would delay certain construction projects if the load wasn't there to justify them. We can't do that because we don't have a Strategist model to actually spit out for us what the logical timing of construction would be.

So this is just an approximation, but assuming that you still built the same plants at all the same times and then just used them less, the total costs would come down, though the unit prices would go up. The LUEC, as you can see, goes up because you have more fixed costs for less production, and that would never happen in reality, because you just wouldn't build the fixed assets. But nonetheless, low fuel and low load, you know, decreases the cost of the Isolated plan in a pretty significant way.

When we look at the Interconnected plan, low fuel costs – oops, sorry – low fuel costs make almost no difference, right? You – nominal dollar totals from $46 to $45.6. It's negligible because low fuel doesn't actually matter much to the Interconnected Island. The dominant cost is Muskrat Falls.

But when – excuse me – when load goes down – load goes down but you have a take-or-pay contract, what do you do? So the assumption that I made is, well, you have to export the surplus. Whatever surplus there is from the take-or-pay contract goes to the export market at whatever price is available in the export market after you take into account some transmission losses. And I assumed for the purposes of these calculations that the price that you would be getting would be the same as $50 from 2012 inflated at 2 per cent annually, which is actually less than the current price today, but that's what I assumed to make the calculations because, assuming we were back in 2012 and we were going to do this kind of analysis in 2012, you could look at Hydro-Québec's export prices and they were at approximately $50 at the time and inflate them forward. That would be one way of doing it.

And so, if you have low load and you're effectively buying Muskrat Falls power at a high price, reselling excess power at a lower price with transmission losses, adds substantially to the burden of ratepayers in Nova Scotia. So you can see that the LUEC goes very, very high because your net power consumption is low and you're having to effectively subsidize your exports. But even then, the Interconnected Island plan is still quite competitive, even with low fuel and low load.

So the comparison here, if you look at right-hand column, this is the Isolated plan, 41 down to 3.6; in the Interconnected plan, 36 down to 3.5. The Interconnected Island plan is still competitive with the Isolated Island plan, at least on this rough approximation. Even with 37 per cent lower fuel prices and a substantially lower load than was the reference load used in 2012, right, if Muskrat Falls had been built on time and on budget, right? That the superiority of the Muskrat Falls plan was robust enough to manage lower load and lower fuel, right, even under those conditions. With the caveat that this is not Strategist model runs, and if you did Strategist model runs these numbers might be a bit different. But even with a Strategist model run, it's probably still going to be in the ballpark, right?

The killer is when you add cost overruns, and bear in mind that this is only cost overruns not schedule overruns. So what was calculated at the time was a 25 per cent cost overrun in the Muskrat Falls plan. And recall that the original Muskrat Falls plan was for a total cost of $7.4 billion, 6.2 of capital cost outlay and 1.2 of financing costs, so the 7.4. So adding 25 per cent cost to that increases from 7.4, right, effectively.

But that cost increase did not include any schedule delay. I'm not quite sure how you get a project, such a large infrastructure, to be 25 per cent more expensive but still be finished on time and, yet, that was the modelling assumption, right? Most projects go over budget because they're behind schedule, they don't go over budget despite being on schedule. It's very hard to conceive of how you would get a 25 per cent budget increase without being behind schedule. Steal prices go up by that, cement prices, labour prices. Most instances your labour prices will go up if there's a strike, but if there's a strike, you're going to have a schedule delay. Like, most cost overruns are inextricably bound up with schedule delays, but no schedule delays were ever modelled in either 2010 or 2012.

Nonetheless, if you add 25 per cent to the capital cost of the Muskrat Falls Project, even a 25 per cent cost increase, under reference assumptions, is not enough to make the Isolated Island superior. The Interconnected plan is still competitive with the Isolated Island plan, even with a 25 per cent cost increase. But as soon as you start adding a 25 per cent cost increase on top of low fuel prices, on top of lower load, then, you know, the competition between the two plans becomes problematic.

This is a direct comparison. So low fuel cost for the Isolated Island plan versus low fuel cost and a 25 per cent cost overrun for the Interconnected plan, you can see that the Isolated plan is superior. The low fuel costs, flat Island load for the Isolated plan versus low fuel cost, flat Island load and 25 per cent cost overrun, again the Isolated is going to be superior. I mean, the reality is that the Interconnected plan was robust – as conceived in 2012, was robust enough to be able to be competitive even if one of the various variables went against it. But when you start layering two variables against it or three variables against it then the Isolated plan starts to look more favourable.

Now, bear in mind, I use 25 per cent because 25 per cent is what was actually modelled back in 2012. The real cost overrun is substantially higher than 25 per cent. But, you know, no attempt was made back in 2012 to model anything higher than a 25 per cent cost overrun. And, to be fair, going back to the World Commission on Dams report, the typical cost overrun for projects – dam projects over the course of 20 – over the course of 50 years, the typical cost overrun was about 25 per cent. So if you're going to model something that would be your starting point, is a 25 per cent cost overrun. But I would argue that you should also be modelling a two-year delay, which was the typical delay that was found in the World Commission on Dams report and that was not done here.

So then you start to come down to the question of judgment. So the Interconnected plan is superior in many scenarios. If you had done a full analysis back in 2012, if you had done 500 Strategist runs and worked through all the different options, you would have found that in the reference scenario, the Interconnected plan is superior. You would have found that all scenarios with high fuel or high load, the Interconnected plan is superior. Scenarios that have higher financing costs in the future, that have interest rates returning to a historical mean, the Interconnected plan is better. And then even scenarios that have low fuel or low load or a construction cost overrun, the Interconnected plan is still superior.

In the minority of scenarios, you would find the Isolated plan is superior. It would be combinations of low fuel prices and low load; it would be combinations of construction cost overruns with low load or low fuel prices; or it would be in supersized cost overruns beyond 25 per cent, right? If you're in a 50 per cent cost-overrun scenario, it almost doesn't matter what the other variables say, right?

But what probability are you going to assign to those? If you fill out a big chart that has, you know, variables in different dimensions and you colour in the space where the Interconnected Island plan is superior and the spaces where the Isolated plan is superior, what probability are you going to put on the one space versus the other and how are you – how is that going to factor into your judgment?

And, again, let's remember, in 2012 the price of oil was US$90 a barrel, right? The export price for power had come down, but it had only recently come down from $90 a megawatt hour, right? It was still, in historical hindsight – well, you know, export prices may be going up again, which would be great for the Interconnected Island plan. And with this $90 a barrel price of oil, why should we assume that it's going to collapse? The price of oil actually didn't fall until July of 2014, a full two years after the decision had been made. So it's not unreasonable when you're sitting in 2012 to believe the price of oil is going to be high for a substantial period.

PIRA's reference forecast was for high oil prices for, you know, the next 20 years going forward. They – yes, they provided a low forecast, 37 per cent down, which actually turned out to be not too far from the truth, as it were, but nonetheless, in 2012, $90 was the price. So what probability would you put on that low-fuel scenario? What was reasonable in 2012 in making this judgment?

But, if we turn from the first test about a risk-adjusted available alternative price to the second test, which is proportionality, suddenly we start running into problems. Yes, you have uncertain futures; yes, you have some futures in which prices are lower and other futures when prices are higher, costs are lower and higher.

But when we look at proportionality, at the distribution of costs, benefits, risks and opportunities as between different stakeholders, now we have a concern. Newfoundland ratepayers appear disproportionately burdened. They bear the full risk of cost overruns in a fixed take-or-pay contract. They bear risk around the future of export prices. They bear risk around load, right? But they have no upside. There's no corresponding upside that they are entitled to that it balances those risks. They have a fixed price: that's their only upside. They're not entitled to any share of export revenues. They're not entitled to any of the future benefits related to Churchill Falls that are created by the Muskrat Falls plan.

The Newfoundland government, or taxpayer or Nalcor – which is all kind of the same thing – has a guaranteed return on its full equity commitment, including equity committed to cost overruns and schedule delays. A full return on equity for all of that at 8 per cent, which was required under the federal loan guarantee structure.

Also, if there's any value that comes out of exports, that goes to Nalcor and the taxpayer. If there's additional value from the ancillary benefits, in terms of local jobs in First Nations and environmental impacts and all the rest of it, that accrues to the government and taxpayer. Ratepayer doesn't really enter into any of that. And the strategic advantage for Churchill Falls, which was created by the Muskrat Falls plan, at least on its face, all flows to the taxpayer, to the government, right? There is no – nowhere in the Muskrat Falls power plan does it say, and cheaper power will in future be available from Churchill Falls and you will be entitled to it, right?

Now, I want to contrast this to Nova Scotia because in Nova Scotia, they agreed to pay for the Maritime Link construction and operating cost over the course of 35 years in exchange for some of the power of Muskrat Falls. And the price for that power was actually higher than what could otherwise have been produced in Nova Scotia at the time. So there was a burden there. But the corresponding upside opportunity was the potential to buy lower-priced excess spot power that might come through the export markets from Muskrat Falls. So there was a burden and there was an opportunity to match it, right? Nova Scotia ratepayers got both sides of that transaction. They took a similar risk at a lower total burden level, but there was an opportunity to match the risk that they were taking in terms of cost overruns and schedule delays.

The Newfoundland ratepayer has no such upside opportunity to match the downside risk, and the Newfoundland government and taxpayer and Nalcor doesn't have the downside risk to match the upside opportunities. There is a disproportionality there.

Now, sure, Newfoundland government represents Newfoundland ratepayers, and Newfoundland taxpayers are the same group of people, the same group of entities and institutions as Newfoundland ratepayers. So you could say, well, it's all the same thing, right? It's all being recycled internally. But the reality is that ratepayers are not the same thing as taxpayers. The distribution of ratepayer costs and burdens is very, very different from the distribution of taxpayer costs. Ratepayers pay their electricity costs because they consume electricity. Whoever consumes more pays more. Taxpayers, whether it's personal income tax or corporate income tax or sales tax, is distributed completely differently.

And so if the benefits of Churchill Falls, for example, accrue to taxpayers, those benefits will be distributed in whatever way the government sees fit. That doesn't necessarily mean that ratepayers are going to get any benefit that's proportional to what they paid in the Muskrat Falls plan. So this disproportionality is an enormous problem in terms of coming to a conclusion that the Interconnected plan was actually fair for ratepayers.

Yes, the Interconnected plan, as we said here, in many possible future scenarios is superior to the Isolated Island plan. But the distribution of cost and benefits, risks and opportunities was really quite disproportionate. So it would be difficult to come to a conclusion that it was actually fair for ratepayers. All with the caveat that this is us in 2019 looking back at 2012, right? No one asked me in 2012 to do a fairness opinion on this proposal, right? But had someone asked me to do a fairness opinion on this proposal, this is the kind of a process that I would have followed, and that's really the best that I can do with this exercise.

Another point before the conclusion to this presentation: I think it's important to sort of look holistically at what's happened with the Muskrat Falls plan because ratepayers are being treated very differently across time.

Once the Muskrat Falls generating station comes into service, basically, for 20 years or so, ratepayers are going to be bearing the full burden of the Muskrat Falls PPA price and they're going to pay the tariff for the Labrador-Island Link. And that tariff will start out being quite high because of cost-of-service economics. The only self-help that's going to be available to ratepayers is to export unneeded energy. And, unfortunately, if export prices continue to be low, that's not going to be much in the way of self-help.

The circumstance changes somewhat in 2041. The burden of the Muskrat Falls PPA will actually be getting worse because the amount of power that's being delivered on the fixed take-or-pay contract goes up and the price goes up with inflation, but the Labrador-Island Link tariffs are declining over time. However, in 2041, by that point, Churchill Falls will have been renegotiated and Churchill Falls will be delivering value. That value, at least as of today, all accrues to the taxpayer, though it will be up to the government to decide whether some of that value should accrue to ratepayers to provide ratepayers some relief. There is the possibility that ratepayers in the 2041 to 2070 period could be better off than ratepayers in the first period of 20 years if some relief is offered out of the value from Churchill Falls.

And then finally, post-2070, the Muskrat Falls PPA will finish, and Muskrat Falls debt will be fully amortized. Then Muskrat Falls will suddenly look kind of like Churchill Falls looks like today, which is extremely cheap with a hundred years of life left in it. And so ratepayers, post-2070, will be in the happy circumstance of having access to both the Muskrat Falls generating station and the Churchill Falls generating station. There's a clear inequity that has been created amongst the ratepayer pool over the next 50 years: A very heavy burden for the first 20 years, a potentially lighter burden for the 30 years after that and then much, much lower burdens.

Partly, this is an inevitable consequence of any expensive long-lived infrastructure project. Expensive long-lived infrastructure projects are almost always amortized in a period of time that's less than their full life. So, there's always a tail at the end of life of an infrastructure project where people who are lucky enough to be alive at the time get benefits that they didn't pay for, right?

But that doesn't necessarily have to be the end of the story. I mean, there is a real question as to whether it's possible to transfer any value between generations to alleviate some of the burden that's going to apply for the first 20 years, rather than simply saying it has to – you know, you have to grin and bear it, ratepayers.

Transferring value between generations is what debt instruments have traditionally been designed for, right? Effectively, borrowing money that will be repaid later when cash flows are higher is what you do with long-lived projects in many instances. And, so, I think it's important not to dismiss it as impossible; to say: Oh, for the next 20 years, costs are going to be much higher and there's nothing we can do about it.

The question is: Is there the will and interest to do that and is it worth it, right? Because any – the cost – the interest costs of transferring value over time erode that value. Even 3 per cent interest in 20 years erodes half of the value that you're talking about, right? So, you know, there's a question about whether to pursue mitigation for ratepayers and at what cost and what can reasonably be achieved, right? But it has to explicitly be an intergenerational transfer – an evening-out or a flattening, if you will, because anything other than that doesn't really make sense.

So, conclusions – the supporting analysis for the Muskrat Falls Project was deeply flawed, and I've gone over this a few times, but both because of the process followed and because of the lack of recognition of the strategic importance of Churchill Falls. Having said that, a full analysis at the time might have resulted in a reasonable defence of the Muskrat Falls Project on a cost basis, if not necessarily on an allocation of burdens basis. Because that disproportioned allocation of cost, benefits, risks and opportunities, I think, would have pointed to unfairness. But had that analysis been done at the time, maybe a different arrangement would have been structured for ratepayers. And I think that's an important consideration.

Finally, it has – the Muskrat Falls plan has created a significant long-term generational inequity, which could, theoretically, be at least partly addressed. But it does require a judgment that at least some of the value that accrues to Churchill Falls after 2041 should be for ratepayers and not all for taxpayers. And I think that's a controversial judgment in and of itself. That has to be, you know, a decision made in Newfoundland.

And that's my presentation.

THE COMMISSIONER: All right.

Mr. Collins, any questions?

MR. COLLINS: Thank you.

You've estimated, I believe, that the Churchill Falls plant could provide perhaps $500 million of value per year to the province, starting in 2041. Is that about right? And that's in today's dollars?

MR. COLAIACOVO: In today's dollars, that's right.

MR. COLLINS: So, in today's dollars, I believe, the – our economy's about $33 billion a year, (inaudible) GDP, how significant is $500 million a year to an economy of that size?

MR. COLAIACOVO: Well, I'm not sure GDP is the right metric, first of all. So the profit – the cash flow potential, as I've said, from Churchill Falls – well, today, is likely upwards of a billion, I mean – a billion to $1.3 billion, likely is accruing to Hydro-Québec, based on their resale of Churchill Falls power in the export markets. If, in future, at least half of that accrued to Newfoundland, then that would not come at the cost of any effort, right?

When you talk about GDP, you're talking about people who are – there's labour and there's investment that produces that GDP. This is a – in effect, a net profit, investments all been amortized and paid for. So it's not just a matter of comparing 500 or a billion dollars to a $33 billion economy. A more relevant metric might be the province's revenues, the provincial government's revenues.

So I believe the budget for this year for the provincial government is something on the order of $6 billion of revenue. And so, a half billion dollars would be almost a 10 per cent revenue increase. And that would be a 10 per cent revenue increase without tax increases. They would just be, you know, a bolt from the blue, all right?

And so I think it has to be understood in those terms. It's much more significant than just a $500-million increase in GDP. Right?

MR. COLLINS: At a high level, how does Hydro-Québec use the energy and capacity it currently gets from the Upper Churchill?

MR. COLAIACOVO: Well, as – as you saw from one of the slides in my presentation, Hydro-Québec is exporting a substantial amount of power. In effect, the vast – well, I'll put it this way, if they did not receive power from Churchill Falls, they would still have enough supply for their domestic purposes, be fairly close but they would still be able to serve their domestic needs. Which means Churchill Falls is effectively surplus and goes straight to exports for them. And given that they have been achieving a price for exports in the range of $40 to $45 in the last few years, per megawatt hour, and that's the value they're getting from it.

Now they don't get all of the output of the station. They get a portion of the vast majority, but they get less than the full output of the station.

MR. COLLINS: How – how much energy and capacity will they need in 2041? Is it – will – will Churchill Falls still surplus to them then?

MR. COLAIACOVO: I – that requires an understanding of the future of their – of Quebec's load, which I'm not really competent to provide. But I also think it's instructive that they have been steadily building facilities. I think at – in the past, there certainly were times when Churchill Falls power was necessary to serve Quebec domestic load. But they have built a lot of facilities and including – I mean, their – their main facilities are still in construction now. Some of them are going to be completed over the next few years and they're already looking at additional facilities that they would like to build.

So I think it's fair to assume that their plan is to be able to serve domestic load domestically. And they want to be in a position where Churchill Falls will not be required for them. That would be the smart thing to do, from a commercial perspective, certainly.

MR. COLLINS: How would it change the negotiations for them if they did need Churchill Falls, if they needed it to keep the lights on?

MR. COLAIACOVO: Well, then clearly that would give Newfoundland some leverage in the discussions. Which is why, as I said, commercially it would make sense for them to do everything they could do to put themselves in a position where it was not necessary. That would maximize their leverage in the negotiations.

So I would suspect, and I would expect that they're going to continue to build facilities to ensure that they'd have no need of Churchill Falls for domestic load.

MR. COLLINS: If you look at the cost per megawatt of their recent facilities, to your knowledge, is that cost greater or less –

MR. COLAIACOVO: Oh, it's dramatically –

MR. COLLINS: – than export prices?

MR. COLAIACOVO: Oh, it's dramatically higher.

So there has been no publicly available, definitive cost of the Romaine construction, for example. The Romaine facilities is a complex of facilities on the Romaine River. They're building a total capacity of 1,550 megawatts, combined. The – I think it's divided, if I recall correctly, in five different units down the river. But there have been some estimates, publicly shared estimates, that the cost of power coming out of that facility is in the range of $65.

So $65, as compared to their $2 that they pay at Churchill Falls, is obviously dramatically different. But – and frankly, even $65, compared to their current export prices in the $40 range is a significant difference. But with the caveat that their realized export prices are a combination of spot and firm. And so their effort is always to sell firm power contracts, which are more expensive.

So, you know, the Romaine plants, if they are producing power at a break-even cost of $65, are still competitive in a North American sense. But, you know, that's the difference in cost between a brand new facility and a depreciated facility.

MR. COLLINS: Is it possible that Hydro-Québec will, in the coming decades, put significant resources into building cost-neutral or potentially cost-losing generating plants in order to prepare themselves for the negotiation in 2041?

MR. COLAIACOVO: I think you would have to be assuming a substantial increase in load because they have so much surplus power today that, you know, only if there was massive electrification of transportation and industrial processes and so on would their load get to the point, I think, where they would be in trouble.

The other aspect to it is that Quebec is quite strong, as is British Columbia, for example, in electricity trading because of their storage capacity. And so, even if they may have a challenge in terms of total load – if their load – if they're having substantial load growth, they could still buy a load and, you know, buy and sell power to manage their peaks.

I think it would be a stretch to conclude that they would have a need to build uneconomic facilities to prepare for 2041.

MR. COLLINS: Let's contemplate for a moment a scenario where North American energy prices are low in 2041, for example, a scenario where the cost of renewables continues to fall precipitously. How likely is a scenario like that and how would it affect the value of Churchill Falls in 2041?

MR. COLAIACOVO: Well – so we've seen the price of renewables come down dramatically, right? The recent RFP for wind power in Alberta – there have been a couple in the last two years – resulted in prices between $36 and $43 a megawatt hour for fixed 20-year contracts.

Bear in mind that those are fixed baseload contracts for intermittent supply, which is of lower quality than total system supply. So, it's not quite the same thing as having baseload power at your beck and call. So you have to be careful about comparing apples and oranges. But it's undeniable that renewable energy costs have come down dramatically.

The cheapest contract in the world was about a year ago, a solar – a 500-megawatt solar plant in the Atacama Desert in Chile for $23 a megawatt hour. But that's the single best place in the world for a solar plant. Nowhere else compares to that, right?

So prices have come down. An acquaintance of mine is in the middle of modelling what the impact would be on the New York power price if there were 12,000 megawatts of offshore wind built in New York. Well, that will have a substantial price – you know, impact on the price of power in New York and therefore on the price of export markets.

Having said all that, the price of production at Churchill Falls is $3 a megawatt hour and it's also flexible storage. So even if you're producing offshore wind for $35, $3 is still pretty competitive. The issue really comes down to the cost of transmission. And bear in mind if that offshore wind farm is priced at $35, it still requires transmission interconnection which is going to be some additional money.

So, you know, really the issue is what is it going to cost to transmit power from Churchill Falls? The $3 cost of production at Churchill Falls will be competitive in almost any future scenario. Now, can it bear very expensive transmission? I think that's where you start to get into a question, and what profit margin is left after you cover the cost of transmission.

You know, the other piece here is that if intermittent renewables, like wind and solar, begin to predominate in any electricity system, then you need storage which means battery, or you need gas peakers to support them. In either case, those things are more expensive than the renewable energy themselves. So, if you're providing electricity service, the question is: Exactly which service are you providing and how much can you charge for it? I think it's a bit of a mistake to isolate the cost of power individually from different kinds of assets because what matters is the need to have a system that provides reliable power and what resources do you need to get there.

MR. COLLINS: Let's also contemplate a scenario where energy prices are high in 2041 and, for example, a scenario where society successfully transitions off most fossil fuels, but the costs of renewables doesn't continue to fall. How does that affect the value of Churchill Falls power in 2041?

MR. COLAIACOVO: It just becomes much more profitable. I mean the costs are fixed, right, effectively. The costs of operation at Churchill Falls are very low and they're going to be very low until the plant is no long usable.

I mean, eventually you have to, you know, replace switchgear, you may have to replace a turbine, but the cost of civil infrastructure is the most expensive part of it. And, you know, unless that deteriorates significantly, you know, the plant just becomes more valuable as prices go up.

MR. COLLINS: Absent a deal with Hydro-Québec, is there any way – you've answered this to some extent, but is there any way to get CF(L)Co the right to transmit Upper Churchill power through Quebec? Is there any appeal to FERC that could've changed that result?

MR. COLAIACOVO: Regardless of the letter of the law, I have trouble believing that a province can be compelled to allow transmission across its territory. It's – I think it's also interesting, the United States is divided into three electricity zones: There is the east of the Mississippi zone, the west of the Mississippi zone and then there's ERCOT, which is most of Texas. And Texas is separate from the rest of the United States because they never wanted to connect their electricity system.

And so, you know, for many years ERCOT was outside of the rules that applied to the other two electricity systems. In extreme, there's no reason why Quebec couldn't be outside the system, right? They voluntarily submitted to FERC rules quite some time ago in order to have contracts, but I find it hard to believe that that would override, you know, their commercial interests. I think to assume that there will ever – that transmission can be required as of right is likely going a bit too far. It has to be the result of a commercial negotiation.

MR. COLLINS: I'm wondering a little more, are there steps Nalcor or the province could take to improve the – to create – to change Hydro-Québec's incentives so that the cost of blocking Upper Churchill transmission was lower to them – was higher.

MR. COLAIACOVO: I'm sorry; I don't quite understand the question.

MR. COLLINS: Are there steps the province or Nalcor could take to contact FERC to set up a case to make the prospect of blocking transmission access more painful to Hydro-Québec?

MR. COLAIACOVO: Yeah, I think that's a question more for a regulatory lawyer than for me, I'm afraid.

MR. COLLINS: Yeah.

There's a lot of history between the province and Hydro-Québec about the Upper Churchill. How realistic is it to expect that this is going to be an ordinary commercial negotiation?

MR. COLAIACOVO: I think every effort has to be made to be as rational and commercial as possible and not to jump to the conclusion that a transaction is not possible. There's no reason to believe that Quebec's incentives won't be what they are now, which is to maximize their profits from the facility, however those profits result, whether it's through some combination of transmission tariffs and arbitrage rights and contract rights.

I think the fact that the Muskrat Falls infrastructure has been built, and a subsea transmission route is a real alternative, is going to set the floor for the discussions. And as long as it's pursued on that basis, a, you know, a real economic alternative – that sets the floor for the negotiation. It should be rational. There's no reason for it not to be rational.

I think the enmity, historically, has been on the Newfoundland side for obvious reasons. I think Quebec will just be a profit maximizer. There's no reason for them to act any differently. So the negotiations should be assumed to be difficult – like any commercial negotiation they would be tough – but there's no reason why they shouldn't be more than that.

MR. COLLINS: Commissioner, it's 12:30. Is this the right time to take a break?

THE COMMISSIONER: Yes, we can take our break now, if that works for you.

MR. COLLINS: It works for me.

THE COMMISSIONER: Okay, let's come back at 2 o'clock.

CLERK: All rise.

Recess

CLERK: All rise.

This Commission of Inquiry is now in session. Please be seated.

THE COMMISSIONER: All right, Mr. Collins, when you're ready.

MR. COLLINS: You've talked to some extent about the strategic benefits of Muskrat Falls in preparing for the 2041 negotiations. To some extent, there are significant benefits of having built the Labrador-Island Link and the Maritime Link. What about the Muskrat Falls generation plant itself?

MR. COLAIACOVO: Excuse me. The Muskrat Falls generating plant is – even if it had been built at budgeted cost, would have been a fairly expensive plant. Certainly as compared to facilities that would be available, just from an energy production perspective, by the time it was expected to come into service. So, if you look, for example, at Quebec's realized export prices, which are in the low- to mid-$40 range, those export prices are lower than the cost of production for Muskrat Falls.

Now, that does not take into account the fact that Muskrat Falls has storage potential, and so Muskrat Falls could be providing storage-type services to people. So it has firming capabilities that are valuable. So even though – it's similar to the Romaine plant in Quebec. Even though the facility's break-even cost of production is higher than export market prices, it doesn't necessarily mean the facility is going to lose money because there are options – there are ways of energy trading to make money, to arbitrage spot prices and so on.

Had – so had it been built for budget, you know, the option – it would've been in the range of what's competitive, but probably not better than that given the way market prices have gone. And if you look back to the 2010 to 2012 period, as I said in my presentation, at the time, the continent was coming off of a period in the early 2000s when prices were much higher, right? And so at the time the decision was taken, there was a lot of uncertainty as to how electricity prices were going to go in the future. Certainly if electricity prices had gone back up to the level of the 2000s, then Muskrat Falls would've been in the money, and exports would've been very valuable.

And having said that, over a 50-year time horizon, frankly, a lot could change. It's entirely possible, you know, in one version of the future, fossil fuels are completely banned in North America – fossil fuel electricity generation is banned – and, you know, a supply crunch forces the price of electricity upwards. In which case, all exports from Muskrat Falls will be making money at that point. You know, that's one possible future.

But there are many other possible futures now, where, you know, renewable energy technology prices are modest or, you know, certainly not more expensive than they are today. In which case, those very high prices don't get achieved again, certainly not in the next couple of decades. And in which case, Muskrat Falls power, even if it had been constructed to budget, would have been hard pressed to make a lot of export revenue.

MR. COLLINS: Another way of looking at the strategic challenge in 2041 is that we are going to have a lot of very cheap energy in capacity in Labrador and we need to find a way to use it or sell it.

MR. COLAIACOVO: That's right.

MR. COLLINS: And a way of looking at the Muskrat Falls generating station is that it is even more energy and capacity in Labrador that we need to find a way to use or sell, so it compounds the problem, perhaps.

MR. COLAIACOVO: Well, to be fair, I mean, the Muskrat Falls generating station was supposed to fill a need before 2041, right? It was supposed to have 25 years of operation before 2041. That was the original schedule. So half of its contracted life was supposed to be over by the time you got to 2041. So it was providing valuable service to the Island of Newfoundland before that supply became available. So, yes, it's true that after 2041, there is that much more available, but it was supposed to be providing an essential service in that 25-year span.

MR. COLLINS: At various points, there have been discussions about the possibility of building Labrador-Island Link on its own, without the Muskrat Falls generating station, perhaps to access recall power, or buying imports with or without a firm arrangement with Quebec. In those scenarios, how much of the strategic benefit of the Muskrat Falls Project, in preparing for 2041, would be achieved?

MR. COLAIACOVO: Well, the Labrador-Island Link is expensive. Recall power is not that voluminous and would not have been sufficient to replace the Holyrood plant. It wouldn't, frankly, make economic sense to build something like the Labrador-Island Link just to carry recall power to the Island of Newfoundland for 25 years, while you'd also have to be building more facilities on the Island of Newfoundland, that once Churchill Falls power became available in 2041 would then be rendered stranded, right?

So – plus the other piece of it is that building the Labrador-Island Link is not quite the same as building the entire, you know, link plus the Maritime Link, in terms of demonstrating the capacity to get the export markets. So, it's not clear that you're getting the same strategic benefit while you're still spending a lot of money for a relatively small amount of power that you're going to be shipping across the straits.

MR. COLLINS: When would negotiations for 2041 naturally begin?

MR. COLAIACOVO: Probably 10 years before.

MR. COLLINS: Ten years before – so 2030?

MR. COLAIACOVO: Yeah. Practically speaking, if you're going to do a major transmission infrastructure project you need 10 years, right? By the time you assemble rights-of-way and permits and construction, you need 10 years.

If you think about the Muskrat Falls plan and, you know, the work beginning for the Muskrat Falls plan, it began, you know, much earlier than the 2010 presentation to the regulator and you look at the expected end date in 2017, as it was supposed to be, I mean, it's s a full 10 years, if not slightly more, of serious development work and planning and preparations and approvals and all the rest of it.

So, 2041 seems like it's a long, long way away but, in reality, it's 10 years from now, because you're going to make decisions 10 years from now that are going to determine what happens in 2041. Because, you know, if you make the decision that you have to proceed with transmission, you're going to do that in 2030.

MR. COLLINS: You've shown us a few graphs illustrating that the Isolated Island is significantly cheaper than the Muskrat Falls Project into the mid-2030s because the Isolated Island Option – until you need to replace Holyrood in the mid-2030s and build new combustion assets and start using more expensive fuel, the Isolated Island is quite a cheap option.

If you build wind with the Isolated Island scenario, would you have time to negotiate with Quebec and have your mid-2030 needs line up with your negotiation schedule?

MR. COLAIACOVO: Yeah. I don't think the – I don't think it's fair to conclude that just because you start a process you're going to conclude the process. You know, discussions with Quebec may stretch on for years before they're done. You may have to, in parallel, be developing the plan to build the transmission line while you negotiate with Quebec about transmission access through Quebec. That could go on for years, right? And the Holyrood plant would be getting older and older and older and, you know, facing end-of-life issues, right?

Spending money on Holyrood life extension and continuing to pay the costs of fuel made sense compared to spending all of the money on infrastructure for the Interconnected Island plan, but fundamentally at some point you're going to have to replace it with more expensive assets, right?

I mean, Holyrood is attractive and it's cheap for those 15 years because it's fully depreciated, because it's an old plant already and you're just life, extending it – you're using Band-Aids to stretch it out. But at some point those things can fail and they do need to be replaced.

And if you were negotiating with Quebec, would you want to negotiate with a gun your head? That you have to get a deal done right away because of the imminent failure of another facility? But then as soon as you spent the money to replace the facility, then you got a full life of a facility in front to you. It doesn't actually work quite so easily or quite so neatly.

MR. COLLINS: Over the last few decades, Newfoundland and Labrador Hydro and Hydro-Québec have had sporadic discussions about developing Gull Island. How likely or desirable is it that in conjunction with talking about the future of the Upper Churchill after 2041, there's a discussion about developing Gull Island?

MR. COLAIACOVO: Gull Island is another attractive construction opportunity, but it's important to bear in mind that Muskrat Falls was chosen for two reasons. In Nalcor's materials, they talk about this. One was Gull Island is larger than was necessary for Newfoundland, but the other was that the expected unit costs of Muskrat Falls were lower than Gull Island.

Gull Island was expected to be more expensive on a per megawatt-hour basis than Muskrat Falls was. So, you know, that question is all going to be: What's the market at the time? Would it be a subject of discussion? Absolutely it would be a subject of discussion. Why wouldn't it be? If you're trying to come to a commercial agreement to take advantage of export markets in some combined way with transmission access through Quebec, and there was the opportunity to build another new plant when Quebec is in the business of building new plants – excuse me – they're building the Romaine plants on an ongoing basis; they've publicly said they want to build more – why wouldn't you consider exploiting Gull Island as well?

But, at the time, depending on markets, depending on prices and depending on expected costs of construction, you know, you would make a decision about whether it's worth pursuing that or not. It's yet another facility in a remote location. And while Quebec has a fairly good track record of building facilities across the province, including in the North, you know, it's – there's always risks. And so it would very much depend, I think, on circumstances at the time.

MR. COLLINS: So in scenarios where North American energy prices are low, Gull Island might not be competitive. But if we assume that prices are high and Gull Island is intrinsically attractive, and if we're looking at the option of building a subsea line, how much more would it cost, potentially, to build an 8,000-megawatt line instead of a 5,000-megawatt line?

MR. COLAIACOVO: Yeah, the – you'd have to get a construction-cost estimator to give you something accurate, but the critical thing is that there's – adding extra strands to a transmission line, adding extra towers overland so that you're twinning or tripling a line is much cheaper than coming up with a new route and permitting and developing a totally new route, right. And so whether you're developing a subsea transmission line for 5,000 or 8,000 megawatts, yes, there will be an increment of difference between the two, but it will always be cheaper than two completely separate, different lines, right?

So there is always benefit to scale, right? On a per-unit basis, the larger infrastructure is going to make more sense. But the actual project itself, the Gull Island project, would have to be intrinsically attractive.

MR. COLLINS: Is it possible that the federal government would have any role in 2041 negotiations, with or without Gull?

MR. COLAIACOVO: If I were advising them, I would say no. The – electricity is a provincial jurisdiction and has been jealously guarded as a provincial jurisdiction all across the country.

The federal government will sometimes get involved in supporting projects, whether those are nuclear facilities or transmission facilities or what have you. The federal government will often support projects if more than one province is involved, as is the case with Muskrat Falls, where there's an opportunity to support. But if there is a dispute or a potential dispute or a commercial negotiation between provinces, between provincial utilities, I don't think the federal government would be well served to become involved in that.

MR. COLLINS: So if Newfoundland and Labrador and Hydro-Québec had a deal to develop Gull Island, could we expect the federal government to support a deal of that sort?

MR. COLAIACOVO: I think if the two provinces could come together and reach a commercial agreement, then they – you know, could they expect support from the federal government? I think they could reasonably ask for it, as has happened in the past, as happened with Muskrat Falls, right? That would obviously depend on the government of the day.

MR. COLLINS: So we've talked about negotiations in around 2030. Would it be possible to move that date up, to negotiate sooner than that, and what would be the cost and benefits of doing so?

MR. COLAIACOVO: Well, the negotiation could happen any time. It all depends what the purpose is.

I mean, you're not going to change the profit that Hydro-Québec expects to get for the balance of its existing contract. All you would be trading is future profit against that existing amount. I mean, commercial contracts are often blended and extended, right? There's blend-and-extend agreements made all the time on commercial contracts.

I'm not so sure that's what you want to be doing at this point. The – you know, I think looking forward to the expiration of the contract and thinking realistically about what alternatives would be required really does lead you to that 2030 time point, to sort of knock on the door and start having a discussion.

Before that, I think you're just giving things away.

MR. COLLINS: Would it be possible that an early negotiation could make more funds available for rate mitigation, for example, to mitigate the problems of generational unfairness that you've identified?

MR. COLAIACOVO: That would just be another way of transferring wealth from the future into the present.

MR. COLLINS: So it would be the same as debt, for example.

MR. COLAIACOVO: You could do that with or without Hydro-Québec. It would just be a mechanism.

MR. COLLINS: What should the Government of Newfoundland and Labrador and Nalcor be doing to prepare for 2041, in your mind?

MR. COLAIACOVO: Well, I think before even starting a negotiation with Hydro-Québec, it's to – is to work on the subsea-transmission route. You know, there are all – there are different stages of development, and I think even before opening any serious discussion, some development of that option will have to be done in order to have a sense of what the real economic cost is, because that will set the floor for the negotiations. And so you don't want to go into negotiations blind.

Now, that's more than 10 years away. I don't think it's realistic or desirable to begin the process too early because technology does change and high-voltage transmission technology is still a developing area. So you're going to want to wait and see what the costs look like as you come closer to the time when negotiations would likely start.

MR. COLLINS: From Nalcor's perspective, what's the cost of the Maritime Link transactions?

MR. COLAIACOVO: Well, the transaction was originally – I mean, the quote was 20 for 20, right, 20 per cent of the energy in exchange for, what was, 20 per cent of the budgeted cost.

The – if you actually look at the price of power from the Nova Scotia perspective, for the amount – the 895-gigawatt hours per year for 35 years that Nova Scotia is getting in exchange for building the $1.6-billion Maritime Link – plus there is a small amount of additional power in the first five years. When you divide that up, the LUEC of that power – I'm stretching back here – but if I recall correctly, the LUEC of that power, under a bunch of different scenario assumptions, was almost $100 a megawatt hour. And so that price of power was more expensive for Nova Scotia than just importing power from the United States, for example, right? So they paid a premium for that power.

But the benefit was putting the infrastructure in place and being able to also buy additional power, presumably at a much lower price, right? The whole point of the exercise from a Nova Scotia perspective was to be on a transmission route, right, that ran from Newfoundland and Labrador down to the US. And so as Newfoundland and Labrador was looking to sell market-priced power on the spot markets in the US, Nova Scotia would have an opportunity to buy some of that and it would be cheaper than $100 a megawatt hour. So, from an average perspective, Nova Scotia expects to come out reasonably in the money, in terms of the cost of power in Nova Scotia.

So if you look at it from a perspective, now, flip it around and look at Nalcor, and say if Nova Scotia ratepayers were not picking up the cost of the Maritime Link, if that cost was being absorbed as part of the Muskrat Falls Project, then export prices for that 895-megawatt hours of power would have to be $100. If they're less than $100, it would actually be more of a burden to the Muskrat Falls Project. And the brute fact of the matter is export prices are much less than $100. So that 895-gigawatt hours of power, that's going to Nova Scotia, is going at a premium price when you look at the cost of building the infrastructure.

MR. COLLINS: Another aspect of the Maritime Link transactions is that Emera got the right to invest in the Labrador-Island Link. We've heard some evidence that the provincial government is – the equity return the provincial government is getting on its investment in the Labrador-Island Link is significantly higher than the cost of borrowing money and so that there's a net dividend to the provincial government, which is a benefit of the project for the province and the taxpayer.

Is it reasonable to say that one consequence of the Maritime Link transactions is that much of that – of the potential net benefit of net dividends in the Labrador-Island Link has been transferred to Emera instead of being retained by the government?

MR. COLAIACOVO: So my –

MR. COLLINS: So if the provincial – sorry.

MR. COLAIACOVO: Well, my understanding of the way the financial arrangements are organized, so Emera got the right to put 49 per cent of the equity required for all of the transmission included in the Muskrat Falls plan, including the LTA, the LIL and the Maritime Link. Most of which is in the Maritime Link, and some of which – the excess portion of which, is in the Labrador-Island Link. None is in the Labrador Transmission Assets, which is why the Labrador Transmission Assets could be included in the PPA, as opposed to the cost-of-service arrangement around the Labrador-Island Link.

Emera was assured that they would get a regulated commercial return on equity for their investment. So the Labrador-Island Link cost-of-service contract is structured to include a commercial return on equity. Which I believe, if I'm not mistaken, is about 9, 9.25, 9.5 per cent, right now, the regulated return on equity that's applicable in Newfoundland. And that's the rate that's included in the cost-of-service structure for the Labrador-Island Link.

Because Nalcor is putting in the rest of the equity in the Labrador-Island Link, they're getting the same return on equity as part of the contract – the part of the arrangement. It's not really a contract, it's a cost-of-service regulated tariff. What Nalcor does with that after they receive it – that I don't know, in – you know, in terms of Nalcor's internal arrangements. But they're getting the same commercial return on equity as Emera is getting, because that's the arrangement that was put in place.

MR. COLLINS: Insofar as the commercial return on equity is higher than the cost of borrowing capital in the financial markets.

MR. COLAIACOVO: For who?

MR. COLLINS: Nalcor's capital comes from the provincial government.

MR. COLAIACOVO: Right, so what you're talking about is the government cost of money, which is debt, as opposed to commercial cost of equity –

MR. COLLINS: Yes.

MR. COLAIACOVO: – which is not debt. And yes, there is a difference between the cost of commercial equity and the cost of debt. Typically, on the range of 5 to 6 per cent is the spread between the two. But Emera's money is equity, which they raise in the public capital markets as utility equity funds. And the cost of capital in the – is really – the cost of raising that kind of money is in the 8 to 9 per cent range, at the moment, in the market.

And regulated costs of equity, across Canada, are all in that range. They're all in sort of the 8½ to 9½ range, depending on which provincial jurisdiction you're in. You look at the regulated cost of equity for transmission and distribution companies, it's pretty much all there.

Yes, for a government-owned entity like Nalcor or Manitoba Hydro or SaskPower or BC Hydro, they all get their money and a provincial government guaranteed basis where long-term money is at 3 per cent. But it's still at-risk equity.

There is a – if you go back to – in my presentation, I talked about what's the real cost of capital. The real cost of capital is the cost of the – the time value of money plus the opportunity cost of the money plus risk. If you look at an electricity enterprise – at the equity in an electricity enterprise, on the assumption that inflation is 1.5 to 2 per cent, 3 per cent does not capture the opportunity cost and the risk cost of money, right? The opportunity cost and risk cost of money in an electricity enterprise is 8 to 9 per cent, if not potentially more, depending on the details of the asset on the enterprise.

The equity portion, just because it's coming from the government – if the government's cost to funds, does not mean that that cost to funds is appropriate for the amount of risk being taken in the enterprise. There's a reason why the market values equity at that level.

MR. COLLINS: So, the Commission has heard that the net dividend – the spread on the government's investment – the extent of which the equity return we're getting is higher than the cost of debt is a benefit to the taxpayer.

MR. COLAIACOVO: It's just compensation for risk.

MR. COLLINS: So –

MR. COLAIACOVO: Risk doesn't go away ever. You know, there is no way to mitigate risk in reality. You manage it. You blend it in a portfolio with other assets that may have lower risk, but you can't just wish it away.

So, the reason equity is more expensive than debt is because it's riskier. So, that spread is compensation risk. It's – it looks like income on an accounting statement, but in economic terms, it's just compensation for risk.

MR. COLLINS: And, so, what I hear you saying is – I want to confirm this is a fair summary – that we have given the right to invest in the Labrador-Island Link to Emera. That's one of the consequences of the transaction, but it's not really a cost because the opportunity is not worth that much.

MR. COLAIACOVO: I think they've been given the right to invest at a commercially reasonable price. And bear in mind, one of the reasons they were given the right to invest in the Labrador-Island Link, it was not for free, it was in exchange for Emera arranging transmission through New Brunswick based on transmission rights that they had previously secured. So they were giving something up to get that right to invest, it wasn't free. So they got the right to invest and to get a commercial return on that investment, but they did hand over something that valuable in return.

MR. COLLINS: What I'm trying to get at, it's one thing to say that the arrangement with Emera was fair and it's another thing to say that there wasn't a significant cost to it. Was us giving – was Newfoundland and Labrador, or Nalcor, giving Emera the right to invest in the Labrador-Island Link, was that a significant cost?

MR. COLAIACOVO: Yeah, I'm trying to make sure I'm not misunderstanding what you mean, but the project would not have been possible otherwise, therefore, it was a reasonable cost.

MR. COLLINS: (Inaudible.)

MR. COLAIACOVO: Right? Because if the transmission rights through New Brunswick were not secured, then the whole point of the plan kind of falls apart, right. It was all about having a route to export markets for the excess power from Muskrat Falls.

And so, those transmission rights through New Brunswick and into Maine were critical, and the cost of getting those transmission rights was allowing Emera to invest in the Labrador-Island Link. And it was a commercial negotiation between two unforced parties, so a commercial negotiation freely concluded between unrelated parties is almost the definition of market fairness.

MR. COLLINS: The cumulative present worth analysis analyzed the cost over the first 50 years of the Muskrat Falls Project was – after the project was expected to come online. As you noted in your report, the 50-year period coincides with the financing arrangements which assumed that the cost of the project be paid back over 50 years.

If you tried to analyze the cumulative present worth over a shorter time frame, how would you deal with the fact that the project would only be partly paid off at the end of the evaluation period?

MR. COLAIACOVO: Well, I think the critical piece of the 50 years is that it was the term of the PPA and it was the obligation on ratepayers to pay a fixed take-or-pay contract price for 50 years. If you look at a shorter period of time, you're ignoring consequences for ratepayers after whatever period you choose. You really have to look at both – excuse me. But, arguably – I mean, traditionally, when you're looking at the LUEC of an asset, of an electricity asset, you actually look at its full life, its full expected life.

So, on a gas plant, a typical gas plant's expected life is 35 years. On a typical wind farm, it's going to be 30. For solar panels, it's gonna be 27 or so, is the typical metric. The problem is when you talk about a hydroelectric facility, well, there are hydroelectric facilities that are well over 100 years and they're still operating.

And, when you use discount rates, after about 50, 60 years or so, the rest of it looks free from the perspective of discount rates. So, you know, theoretically, you could amortize the facility and you could say, well, let's look at the whole life of this hydroelectric facility over an expected life of 150 years. You could do that, but it won't actually have much meaning and no one will give debt that lasts that long.

Until recently, you couldn't get debt longer than 30 years. In the last 10 years or – well, in the last 15 years, the first 50 year debt that I heard about was about 15 years ago. So, you could get a bond for 50 years. But if you can't actually get a bond for that period of time, then, you know, trying to look at a longer period is very difficult.

I mean, it's the intergenerational problem, again. Right? These long-lived assets always create intergenerational problems because the use of discount rates and compounding cost of money really limits how far out in the future you can go.

So inevitably, there's gonna be a burden. Now, theoretically, it could be refinanced from time to time, right? And so, you could, theoretically, stretch costs out, but there's always a risk associated with that.

MR. COLLINS: Is it – can I take from that that the issue is not that we should not have been looking at a 50 year period; is that it should have been a 50 year period as well as the 20 year period –

MR. COLAIACOVO: That's right.

MR. COLLINS: – as well as the 10 year period.

MR. COLAIACOVO: I think it's fair to say that particularly where options have very different shapes over time, as with the two that we looked at on the charts where one – one shape is sort of a gently falling and the other one has a big spike at a certain point. It's valuable to look at the before and afters, right? And to understand exactly what's happening and which cohorts of ratepayers are going to benefit, and which are going to lose out, because that should be part of the analysis. But you have to look at the whole thing. And you also have to look at the day after, because year 51 is important, right? What happens in year 51 is that everything gets a lot cheaper for everybody. And it is important to take that into account as well.

But in the Isolated Island plan there is no year 51, right? There is no sudden drop off, because you're just constantly building new assets as you require them and replacing old assets as they need to be replaced. There are no ultra, long-life assets in the Isolated Island Option, there's just assets that get used up, right?

So, you know, the emphasis was on the 50-year CPW calculation. It should have been more sophisticated than that. But both in terms of looking at segments of the 50 years as well as considering what happens afterwards.

MR. COLLINS: One thing you identify in your report is that the low load, low export price, low fuel price scenario should have been examined. But if it had been examined, the cost at the time – the probability at the time would've been seen as being low. That would've been seen as an unlikely outcome.

Is the idea that those three factors, load, fuel and export prices, are to some extent independent so that you're looking at the odds of three independent –

MR. COLAIACOVO: Yeah.

MR. COLLINS: – things happening?

MR. COLAIACOVO: Well, as it turns out, I think export prices have been demonstrated to be independent of the other two, because Northeastern North American prices have followed the gas price market. The marginal cost of power in most of the Northeastern United States is, in large measure, dependent on the price of gas as a fuel for electricity generation plants. There's a big mix of different kinds of plants, but natural gas is the – on the margin about 40 per cent of the time in New York, in New England, and even in PJM it's on the margin a fair amount of the time.

So the export price of power is largely being driven by natural gas prices. And that's independent of both load and oil prices. Natural gas price has been decoupled from the oil price for many, many years in North America. But from a Newfoundland perspective, I think there is an argument to be made that load and oil prices are not, in fact, independent. If you go back to 2012, when the price of oil was US$90 a barrel, and the economy was booming in Newfoundland because of activity in the oil sector, I think it was natural to assume that continued growth in load was going to follow from economic growth in the oil sector.

After July of 2014 when the price of oil began to collapse and projects all across Canada in the oil sector were cancelled – much more so even in Alberta than here, frankly, but also in Saskatchewan and other places – there was a consequent decline in growth forecasts in the electricity sector. Alberta suffered exactly the same thing; forecast load growth in Alberta has collapsed compared to what it was before 2014.

So for provinces that are resource-dependent economies, where the price of oil is very, very important to the economy, load kind of follows with it.

And so, when the scenario was received from PIRA back in the 2010, '12 period about – you know, here's the forecast price for oil, here's a low case. In all fairness, a low case for oil should likely have been coupled with a lower case for demand because if the price of oil collapsed, it would have – as it did – have an impact on economic growth in the province.

In Ontario, it's not quite the same thing because Ontario is not oil-dependent as an economy, but in Newfoundland, in Alberta, it very much was the case.

MR. COLLINS: I'm gonna suggest that this linkage was knowable at the time and does not require the use of hindsight because if you look at the factors that go into Nalcor's load forecast, one significant factor is personal incomes, another significant factor is housing starts, and a third significant factor is the relative price of oil and electric heat. And all three of those factors, on their face, are likely to be effected by oil prices.

MR. COLAIACOVO: I think that's likely fair. I mean, in that period of time of high oil prices, Newfoundland's economy was doing very well because of high oil prices. That should have been recognized. And so, as long as high oil prices were being forecasted, it was reasonable to expect continued growth or demand, of electricity demand.

If you're gonna look at a case with lower oil prices, presumably that also has coupled with it lower demand. Certainly lower growth, if not absolute declines in demand. But, as we know from the past few years, there actually was an absolute decline in demand.

MR. COLLINS: So when you modelled low growth – low-load growth scenarios in your report, you focused, I believe, on two scenarios. In one of which there's a 1 per cent decline in total load and then on the other of which there's a (inaudible) recession which leads to slowly rising – did you choose those two scenarios because they're the best and most representative examples of low-load futures, or because they're easy to model?

MR. COLAIACOVO: Partly because those – they were ones that I could actually do given the materials that were available.

The 1 per cent decline was just meant to be the loss of a significant facility. For example, an industrial facility closes down, you lose 1 per cent of the load in the province, and assume that that facility never comes back. That's all that was. Has a very marginal impact across most of the prices.

The second one was a stalling of growth and essentially meant to capture something like a decline in oil prices where all the growth that was expected doesn't happen. In actual fact, it was less punitive than what's actually happened because there was an actual dip in absolute demand. But what I did was I flattened the demand curve and assumed that all the excess power would have to be exported. And that went on until 20 – I did it for 10 years and then the assumption of 2 per cent load growth started again after that.

I could have picked other numbers. At a certain point, it was for illustration purposes and sort of directional purposes only. And it's never proper because you really need to do a Strategist model run in order to do that properly.

MR. COLLINS: But if Nalcor were doing the analysis with all their resources, would it be appropriate for them to model a wider set of – a wider range of load cases?

MR. COLAIACOVO: Yeah, well, traditionally, if you look at system plans – whether it's Nova Scotia, Ontario, BC, Alberta – load projections always have a high and a low, right? There's always a high-growth scenario and a low-growth scenario in virtually every system plan, load projection across the country.

And, typically, you know, reasons that are included are expectations about overall economic growth, expectations about conservation, expectations about immigration. I mean, the whole gamut. But the low scenario is, well, if we have a recession, then we're going to end up in the low scenario. Or if some of the major industries in our province – whatever they are, if you're in BC it's the pulp and paper sector or what have you – if they suffer then there's going to be a decline in load, right?

And so you have highs and lows because every province across the country has had, what subsequently are found to be, mistaken projections. That's the nature of projections. Sometimes you're closer and sometimes you're farther away, and so there should always be a bracketing of a high and a low.

MR. COLLINS: Manitoba Hydro International suggested, in reviewing Nalcor's load forecast, that it's accuracy – it was – although it was a well-prepared forecast, it was liable to err by as much as 1 per cent in either direction for every year that you project into the future, so after 10 years, plus or minus 10 percent and presumably after 57 years –

MR. COLAIACOVO: That's right.

MR. COLLINS: And so would it have been appropriate to test those extreme cases or a narrower set?

MR. COLAIACOVO: Absolutely. No, for sure. And Manitoba Hydro International was just talking about normal protocol, right?

They're – you know, the common assumption is that inflation is 2 per cent, right? And that it has been for a long time. But inflation of 2 per cent will double your money, if you wait long enough, right? So it is important to always check the brackets. And sometimes the CONEs have to be even bigger.

I mean, arguably on something like oil prices or – you know, or export prices, the CONEs should be much wider than plus or minus 1 per cent. And PIRA, I think, demonstrated that because their low-oil scenario was 37 per cent lower on, you know, a 2012-dollar real basis, right? So their brackets were very wide. This similar sort of exercise should have been followed for the load growth.

MR. COLLINS: And touching on what you're saying there about PIRA. PIRA's low and high scenarios diverged by 37 per cent within their, I believe, 20-year-forecast period.

MR. COLAIACOVO: That's right.

MR. COLLINS: If you were to extend that forecast 30 years further, should that 37 per cent gap widen?

MR. COLAIACOVO: Normal practice would be you'd just continue the curves at the same acceleration. So if the bottom curve is only rising at 1 per cent a year and the reference curve is rising at two and the high curve is rising at three, then that's where it goes, and the CONE will continue to get bigger over time. And that's what you attest.

But always bear in mind, when you're discounting, your discount rate squeezes all of those things. So you have to be careful because what looks like a large error zone in nominal dollar terms, is actually going to be a much, much smaller error zone when you look at it in discounted terms, right? And these projects are all valued on a discounted basis, because there's risk and because there's uncertainty, right? So, you know, it may seem like these CONEs are getting very, very wide, but all of the uncertainty in these financial models that are long-term models is getting very, very wide, in reality.

MR. COLLINS: My understanding of Nalcor's practice is that they took PIRA's high and low forecasts, when they did their sensitivities, and they escalated them for the remaining 30 years at the same 2 per cent rate, so that the CONE did not grow as the – as we went into the future.

I take it that that would not be the normal practice?

MR. COLAIACOVO: Yeah, you wouldn't normally adjust the direction of the curves.

MR. COLLINS: Stepping back a little bit, the scenarios with high fuel prices and high loads are very favorable for the Interconnected Option, but they are also scenarios where the province, as a whole, is likely thriving. Is that fair?

MR. COLAIACOVO: Sorry, I'm –

MR. COLLINS: The scenarios where fuel prices are high and Island loads are high –

MR. COLAIACOVO: Right.

MR. COLLINS: – is it fair to say that those are scenarios in which the province, as a whole, is likely thriving?

MR. COLAIACOVO: That's probably reasonable.

MR. COLLINS: And that the scenarios with low fuel prices and low loads are scenarios where the province is more likely to be struggling?

MR. COLAIACOVO: That's right.

MR. COLLINS: And so the Interconnected Option – choosing the Interconnected Option makes the good times better and the bad times worse.

MR. COLAIACOVO: I suppose that could be a way to characterize it, yeah.

MR. COLLINS: How would you normally reflect that kind of consideration in a financial analysis?

MR. COLAIACOVO: Well, bear in mind, though, if you look at the Isolated Island plan, if you had chosen the Isolated Island plan and oil prices are high and load is high, then you're spending a lot more on electricity. So from that perspective, the Isolated Island plan is counter-cyclical or – not counter-cyclical, but it's anti-prosperity, right? But on the other hand, where you have low load and low fuel prices, you don't get the full benefit in the Isolated Island plan because you're still building fixed assets. They're just not burning as much, right? So it's still bad, but just not as bad, right?

And so you can't kind of – I'm not sure it's fair to characterize these things in isolation; it's always in contrast, right? The – I think the real question to ask is so, okay, so in good times, the Interconnected Island plan looks like a great home run, right? In bad times, it's going to be painful, so what can we think about to mitigate the pain? That's why you do the scenario, right? You do the scenario to think about, well, can we bear that level of pain and what can we do to mitigate it? And you think about that in advance, right? You don't just leave it to happen.

When you contrast the two, the Interconnected Island plan is going to be more painful than the Isolated Island plan in bad times, which means you should that much more time thinking about what mitigation you're going to do. In good times, to some degree, it doesn't really matter because it's good times, except the fact that the Isolated Island plan is going to be pretty painful in those good times because fuel is going to be expensive and your load is going to be growing quickly. And so you still have to worry about mitigation, but it is just a different kind of mitigation, right?

I think it's a little bit – you have to be careful not to simplify the argument too much.

MR. COLLINS: It's a critique that has been sometimes made of the project that it has a portfolio problem, that instead of hedging our bets or making all bets in the same direction so that if things go wrong, there are no resources necessarily left to mitigate. Is that a fair critique? Or is it a –

MR. COLAIACOVO: Yeah, there is – that's a critique that can be levelled at any large infrastructure project. There are – in something like electricity, where there are many different options –

MR. COLLINS: Mm-hmm.

MR. COLAIACOVO: – the two single largest assets you can build are hydro plants and nuclear plants. And in the past 20 years, by and large, history has not been kind to either hydro plants or nuclear plants because the price per unit, the LUEC of almost every other technology has been falling over the past 20 years. Wind turbines have become cheaper; solar panels have become cheaper; gas turbines have become more efficient, right? The technology has actually been changing, which is an oddity because from about 1920 to about 1990, there was no change in electricity technology. There was a long period of time when you had steam boilers and hydro plants. And then eventually you got nuclear plants, and nuclear plants are just another version of steam boilers.

So, you know, it – technology has been changing quite rapidly, but many jurisdictions have still put money into large projects, whether it's hydroelectric facilities or nuclear facilities, because there is value in some of those large projects. The trick in almost every case is building them on time and on budget. And where they are built on time and on budget, they're enormous successes. And where they're not built on time and on budget, they're massive failures.

And so, yeah, there's a portfolio-risk issue because all your eggs are in one basket. That should not be a blanket argument against all large infrastructure.

MR. COLLINS: I have a few questions about the option of importing power from Quebec. You've explained, to some extent, how starting the Churchill Falls negotiations that far in advance before we – before Newfoundland and Labrador had time to explore – to really explore our alternatives to a deal would be costly.

Is it fair to say that that cost would fall mainly on the taxpayer or the province?

MR. COLAIACOVO: Well, as matters stand, as I understand them, the taxpayers are the only legal or contractual beneficiaries at the moment, of anything that happens at Churchill Falls. The taxpayers own 100 per cent of Nalcor, and Nalcor owns 65.8 per cent of Churchill Falls co – of CF(L)Co. So any negotiations which involve Churchill Falls would, in essence, cost the taxpayers, potentially.

And so, you know, had Nalcor had discussions with Hydro-Québec 10 years ago about potentially importing power from Quebec, you can only assume that that would have entailed some types of concessions around Churchill Falls.

MR. COLLINS: And so that option, to some extent, there would be – the concessions would be concessions probably from the taxpayers. Is it possible that this would nevertheless be a good option for the ratepayers, just in terms of who's getting what from what?

MR. COLAIACOVO: I think you have to assume there that you would've gotten a price from Hydro-Québec that would be any different from what they would've offered to somebody else. And then anything better – quote, unquote – would just be a transfer from taxpayers to ratepayers. And you can do transfers from taxpayers to ratepayers any time you want, literally at the stroke of a government pen.

Many other provinces are doing exactly that, so it's – why would you mediate that through Hydro-Québec?

MR. COLLINS: So you write in your report about the advantages of interconnection, that one of the advantages of the project is that we're now connected to the North American grid. The province's 2007 Energy Plan suggested that the province has a massive energy warehouse and that our energy strategy has to revolve around finding markets for that energy to get the value out of it.

So how – to what extent does the Muskrat Falls Project carry out that strategy? And how realistic was the strategy in 2007, 2012 and today?

MR. COLAIACOVO: Well, I think the Muskrat Falls plan does do what it intended to do in terms of getting access to market, right? The route to market was negotiated and it was guaranteed, right? So there is access to market. Now, the wire that goes from Newfoundland to Nova Scotia is 500 megawatts, so it's skinnier than you would necessarily want, but it is a connection to market. And there's already trading going on across that connection even before the Muskrat Falls is finished. So there will be trading. I think the design does what it promised to do, and, you know, Nalcor will be able to trade across that connection into market.

There is a heavy price to pay in terms of transmission losses, but, you know, I think there's a – a good comparison is actually British Columbia. BC Hydro makes money on its energy trading even year – in years when it's a net importer of power, right, because they are very effective at trading energy in the northwestern United States and, to a lesser extent, in Alberta. Their trading operation is quite efficient and quite ruthless, and they arbitrage highs and lows because British Columbia has storage capacity, and so they're quite effective. Sometimes they're net exporters; sometimes they're net importers, but they always make money because they are making money based on their storage capacity.

Quebec does the same thing but at a much larger scale and with much more of a one-way flavour to it, because they export a lot more. But I think British Columbia is a bit of an instructive exercise: If you do have storage capacity and you have a connection to market, you can make money, right? Can you make enough money? Is your profit margin going to be high enough to compensate you for the cost of the infrastructure that you put in pace? Wholly different question. But connections plus storage give you the opportunity to make money.

MR. COLLINS: If we were looking at $100-per-megawatt export prices, would it be believable that we would now be exploring undeveloped hydro sites on the Island? Perhaps some of the province's wind resource for – ended up in those (inaudible) for export?

MR. COLAIACOVO: I think when – well, I know – when I was providing my report in Nova Scotia, one of the things that we pointed out was once the transmission connection was built between Newfoundland and Nova Scotia, should Newfoundland choose to build more wind power, for example, it could be exported across the lines. That's definitely true. You know, it just comes down to price. If the price – if the intrinsic price of the power at the plant is cheap enough to make export to market valuable, then the transmission capacity makes that possible, right?

So if the export price – if the export market price is high enough, and it's cheaper to develop wind in Newfoundland than there is to develop it off Long Island – because that's part of the issue, right? Wind is freely available in lots of places; some places it's a little stronger than in others, and it comes down to whether your particular location has an advantage. But there is no reason why if the market price were high enough and the demand was there, you wouldn't develop more resources. That's not the market condition today.

MR. COLLINS: Another criticism we've heard of the project is that because of the structure of the escalating Power Purchase Agreement, most of the cost of the generating station falls on the later years of the project when uncertainty is highest so that we've backed into the cost past the area we can foretell – predict with accuracy.

Does that seem like a reasonable critique to you? How do you respond to that?

MR. COLAIACOVO: I actually don't think it's the – it's not the fact that the price escalates by 2 per cent inflation; it's that the volume escalates. The price escalating by 2 per cent inflation is actually pretty reasonable. It's an attempt – that's an attempt at preventing generational inequity. Because that's one of the problems with cost-of-service economic structures: they front-load costs. Under cost of service, things actually get cheaper over time while everything else inflates.

So in a PPA structure, especially a modified PPA structure like the one put in place with prices increasing by inflation, arguably, it's more fair to ratepayers, not less fair, but the volume of power also rises. In that chart that I showed earlier, you show a steady curve as it goes from 2,000 gigawatt hours to 5,000 gigawatt hours. That curve is based on an assumption about the load growth profile of the province, and it's much harder to countenance belief in a load growth profile than it is in 2 per cent inflation.

If I had to bet, I would say 2 per cent inflation is much more accurate than the load growth profile that was included in 2012, right? So, to me, that's the real problem is that there's a take-or-pay contract that's been designed with that steadily increasing supply, whether or not the supply is really going to be required.

MR. COLLINS: And to some extent, any lack of realism in that assumption, does that counteract your other concerns about the generational fairness of this project? Because it would tend to put a greater cost on future generations.

MR. COLAIACOVO: It places a greater cost on future generations if you assume that they don't need the power. So it comes down to scenario modelling, right? In a high load growth scenario, it's not a problem at all. In a low load growth scenario, it's an enormous problem for the future. And in low load growth plus low export prices, it's an enormous burden on the future.

But the – I think that the point that I was trying to stress, when I talked about generations, was not so much just the way that the contract operates in and of itself; it was also the intervening 2041 event in between and then the year after significance, in year 51.

MR. COLLINS: You write in your report about the simple payback period – and you reviewed that this morning also – which looks at the number of years that will be required for the expected cash flows to cover the initial investment. So we've heard that a short payback period is one way to deal with the uncertainty intrinsic in long-term forecasts?

MR. COLAIACOVO: For an investor.

MR. COLLINS: For an investor.

Should the simple payback period have been a major factor in the Muskrat Falls analysis?

MR. COLAIACOVO: Given that most of the focus was on cost to ratepayers, no. This is not really – this is not a project, a plan that was prepared for investment purposes. It's not about choosing the higher IRR or the higher NPV.

In Manitoba, in the NFAT process that I participated in, that was a big focus. There was a lot of discussion about the NPV of different options because the perception was that new construction in Manitoba was going to be profitable and ratepayers would benefit over time because they would be exporting a bunch of power to the United States. Manitoba is not for profit. Manitoba Hydro is a not-for-profit enterprise, and so any benefit they get from exporting automatically goes back to ratepayers. And so there was a lot of emphasis on that metric.

Here in Newfoundland, it's very different because Nalcor is a for-profit enterprise and real equity was being put up by the taxpayer for the Muskrat Falls Project. So there has to be a return on that equity, a return on that taxpayer money. But this wasn't – there was no comparison of the Interconnected versus Isolated plans on the basis of which would have a better return for taxpayers. It was just not a relevant issue, so, therefore, worrying about payback periods is similarly not a central issue.

MR. COLLINS: The Commission has heard some evidence suggesting that Nalcor's estimate and risk analysis could've understated the likely cost of the project. Have you followed this evidence? And if it's accepted, how would it affect your analysis?

MR. COLAIACOVO: In – I read quite a bit of that. When – the standard practice when you're doing financial analysis is to take the budget estimates that you're given – and budget estimates typically also have a high and a low that are included in those – and then you also add one or two layers above on top, right?

Because that's what responsible financial analysis requires, because every proponent has a tendency to wear rose-coloured glasses when it comes to their budget and schedule. And so responsible financial analysis is you ask the question: well, what if it costs a billion dollars more than whatever the extra billion you've already added to your budget?

I think the – it bears a discussion in the record of this Inquiry about a P50 versus a P90 version of pricing, for example. That would be particularly relevant to financial analysis. You know, I think you start with a P90 number and then you would add a P95 number on top of that and then you ask the question: what's P99? Right? And you run a scenario on all of them and see what happens.

I mean when – in Manitoba, we looked at cost overruns of several billion dollars. And, also, more importantly, we looked at the combination of several billion dollars of cost overruns with drought conditions that happen once every hundred years, and the drought happens two years after you finish construction. And so we looked at those kinds of scenarios to see, well, would Manitoba Hydro go bankrupt, right? And in a couple of cases, yeah, they would, and they would have to get bailed out by the provincial government, right?

And so we made that calculation before we commented on whether the plan was a good idea or not, right? Because that's what you're supposed to do when you do responsible financial analysis of these kinds of projects, so …

MR. COLLINS: So when you get the Monte Carlo distribution from the cost engineers and it says it could range from this to this, you don't just take those as the inputs in your financial analysis; you consider a wider range of possibilities.

MR. COLAIACOVO: Usually we just go higher.

MR. COLLINS: You usually just go higher?

MR. COLAIACOVO: You don't bother going lower.

MR. COLLINS: The Commission has also heard some evidence suggesting that the Labrador-Island Link was built with a lower reliability return period than is recommended for comparable high-voltage lines. Have you followed that evidence?

MR. COLAIACOVO: No –

MR. COLLINS: No.

MR. COLAIACOVO: – not to any great degree.

MR. COLLINS: How – if – again, if accepted, how would it affect your analysis?

MR. COLAIACOVO: Again, I mean I think issues around reliability are difficult to financially model because they're typically short term. You're talking about interruptions, right? Most of those kinds of things can be fixed, would be fixed, and so you're not talking about a long-term impact.

What you do model sometimes is natural disasters. So, for example, in Muskrat Falls, the Labrador-Island Link and the Maritime Link, there's sections under water, there's sections above ground. There's always a real issue with a storm destroying a transmission line. One of the obsessions in Manitoba is tornadoes wrecking their high-voltage transmission lines, which is why they're building a second transmission line.

You know, so it's conceivable that, you know, you could have run a scenario that said: What if the Labrador-Island Link went out of commission because a storm took towers down in Labrador, not the underwater portion, but the aboveground portion. And so if you had to – you know, if you got no production and it took a year to repair, how much would that cost? Can – is there enough of a debt reserve, you know? What – yes, there's interruption insurance and so on and so forth, but what does that do to the outcome?

And if one project depends on infrastructure which is physically at risk and another option, like the Isolated Island, does not include the same kinds of physical risks, then you might financially model those two things, but you do them kind of as one-offs.

MR. COLLINS: You've indicated several times that the Strategist program used to develop the Isolated and Interconnection options optimizes based on the assumptions loaded into it, that's – so that's a point that's underlined and emphasized.

The Commission has heard evidence questioning several of the assumptions, as you'd expect: whether or not small hydro sites were included; whether more wind could've been put in as a possibility; whether conservation and demand management ought to have been a supply option; whether the Grand Banks natural gas or liquid natural gas could have been options that were included.

Have you followed any of this evidence, and how would it affect your analysis?

MR. COLAIACOVO: So the – all of you – all – that's all true. There's no question that if you change load assumption, Strategist outputs differ. There's no question that if you – part of what Strategist asks is what the cost of a wind project would be, for example. And if you assume that 10 years from now, when projects are going to cost $2 million a megawatt versus a million and a half a megawatt, that makes a difference in the Strategist program.

And so, you know, when you're looking forward for 50 years, you do have to make an assumption about whether capital costs and performance criteria for different technologies are going to be flat or whether they're going to change. And, for example, I think there is a good reason to believe that the effective price per megawatt hour of – for wind turbines is going to continue to decline somewhat over the next 20 years. If that had been input into the Strategist model, you might get a different outcome.

The same thing with the effective efficiency of turbines; as I said earlier, they've become 5 per cent more efficient in the last 20 years. They might still become 5 per cent more efficient in the next 20 years as well. If you included in a Strategist model as an assumption, it might give you a different output, right? So, all of those are important.

I think you need to – those questions get asked, right? It's part of the exercise of understanding exactly which scenarios were run through Strategist, based on which assumptions. And if there is a robust regulatory process around the system plan, all of that comes to light and you get the opportunity to ask about those assumptions, and sometimes you get the opportunity to see different options – different assumptions run through the model.

Strategist is just a tool. It's a very good tool. It's just a tool. You put in assumptions; you get answers.

MR. COLLINS: But, for example, if a different set of assumptions shaved a billion dollars off the long-term cost of the Isolated Option, that would tend to reduce the number of scenarios in which the Interconnected Option was preferred.

MR. COLAIACOVO: That's right.

MR. COLLINS: And you haven't factored anything in for – you've identified it as a possibility but not factored it into your analysis.

MR. COLAIACOVO: I pointed out that technology change was not – to the best of my knowledge, was not taken into account. That often in system plans, you see discussions about the historical price curves associated with different technologies and you're told in our plans we've assumed either that this curve is going to continue, you know, going down, which is what many of them have, or it's going to be flat, right? But there is at least that discussion. That did not appear in the materials presented by Nalcor.

MR. COLLINS: The government has announced a rate mitigation plan under which its equity returns, together with some oil and gas revenues and power export revenues, will be used to lower rates. How at a high level does a mitigation plan of that kind address your concerns about fairness between generations?

MR. COLAIACOVO: I think it's a reasonable step for the government to take. The – you won't know until the costs are completed of what the full extent of the impact is, but it's a – the original package of arrangements was inequitable as between the government and the ratepayer. And so some transfer, as between the government's returns and the ratepayers, I think is appropriate to address that.

I'm not sure that still changes anything about the intergenerational inequity, because the intergenerational inequity, I think, is still going to be there, but it helps to address the disproportionality between the taxpayer and the ratepayer.

MR. COLLINS: I have one very small picky question left; if we go to your presentation, P-04464 at page 25.

THE COMMISSIONER: Page 55?

MR. COLLINS: Twenty-five.

CLERK: What page is it?

MR. COLLINS: Twenty-five.

You discuss the 2010 process before the regulator. The evidence in front of the Commission is that the Public Utilities Board process occurred from 2011 to 2012.

MR. COLAIACOVO: Sorry. Yeah, I thought it started in 2010. I'm – my apologies.

MR. COLLINS: Is there – is it possible that you're referring to the process focused on the Decision Gate 2 numbers?

MR. COLAIACOVO: Yeah, there's the – 2010 was the – it was all in 2010 dollars, all the materials. But I actually thought their first submission was towards the end of 2010, but I might be wrong.

MR. COLLINS: The Decision Gate 2 – the project passed Decision Gate 2 in November 2010.

MR. COLAIACOVO: Sorry?

MR. COLLINS: The project passed Decision Gate 2 in November 2010.

MR. COLAIACOVO: Okay.

MR. COLLINS: The Public Utilities Board process followed after – the year after.

Those are my questions, Commissioner.

THE COMMISSIONER: Okay.

I think we'll take our 10 minutes here now and then we'll come back and begin cross-examination, so 10 minutes.

CLERK: All rise.

Recess

CLERK: All rise.

Please be seated.

THE COMMISSIONER: Okay.

All right, Province of Newfoundland and Labrador.

MR. COLLINS: Commissioner, before we begin, could I –

THE COMMISSIONER: Oh, sorry.

MR. COLLINS: – ask to enter Exhibit P-04468?

THE COMMISSIONER: All right, that will be entered.

Government of Newfoundland and Labrador.

MR. LEAMON: I have no questions, Commissioner.

THE COMMISSIONER: Okay.

I understand that Mr. Simmons and that you as well, both agreed that Mr. Smith can go – proceed with regards to Mr. Ed Martin?

Okay, Mister – so Edmund Martin, cross-examination.

MR. SMITH: Good afternoon, Sir. Harold –

MR. COLAIACOVO: Afternoon.

MR. SMITH: – Smith for Edmund Martin.

I'd like to take you –

THE COMMISSIONER: One thing you might want to do – I think as each individual comes up, in fairness to this witness, I think you should identify who your client is. I'm –

MR. SMITH: Oh, okay.

THE COMMISSIONER: – not sure he would know.

MR. SMITH: I haven't had to do that –

THE COMMISSIONER: Right, I agree.

MR. SMITH: – before today.

Mr. Martin is the former CEO of Nalcor.

MR. COLAIACOVO: I met him.

MR. SMITH: I'd like you to turn to four – I think it's 04445, which is, I think, your actual paper presentation.

MR. COLAIACOVO: Report.

MR. SMITH: Yes.

And could we go to page 76? Okay and scroll down to lines 29 to 36.

In your report and in your evidence earlier today, you opined that the ratepayers will endure a disproportionate disadvantage versus the advantages of rising to the Newfoundland government. And my friend, Mr. Collins, for the Commission asked you near the end of his questions whether or not the rate mitigation plan – and I think that shows up at P-04449, page 6.

THE COMMISSIONER: So this would be on your screen.

MR. SMITH: And scroll a little bit down to managing Muskrat Falls section there. You'll see that in the rate mitigation plan, as proposed government so far, they identify essentially 525 – $500-and-some-odd million dollars annually in rate mitigation. And the Premier, in his testimony, testified that the plan would be to actually reduce the rate to 13.5 cents, okay, across the board for each ratepayer, okay?

And I'm again asking what Mr. Collins asked, perhaps in a not so an eloquent a way, but I'm asking you: Doesn't that truly address the – if you will, your words; I think, the disproportionate disadvantage that the ratepayer would suffer under the prime.

MR. COLAIACOVO: So, two things, this announcement was made relatively recently.

MR. SMITH: Yes.

MR. COLAIACOVO: So, it's subsequent to the arrangements, right?

All of my report was focused on the decision-making in 2012. I did not take into account decisions that were made subsequent to the Muskrat Falls plan, like this, because it's very clear that the government has the ability to mitigate, right? The calculation that's here – I cannot comment on whether it actually mitigates the total cost down to 13.5 cents –

MR. SMITH: No –

MR. COLAIACOVO: – and –

MR. SMITH: – but that's what the Premier said –

MR. COLAIACOVO: – right.

MR. SMITH: – in the testimony before the Commission.

MR. COLAIACOVO: Right. And if that's the case, then, yes, it is quite conceivable that it (inaudible) mitigate the intergenerational equity.

I think, though, that if the mitigation is to that extent, then there's a legitimate question about whether the taxpayers are getting a return on the investment that was put into Muskrat Falls in the first place. So, there is no question that the government – the taxpayer has the ability to transfer value to the ratepayer to whatever extent is decided. And, yes, it could be enough of a transfer to address the intergenerational equity.

That, then, has created a different issue, which is whether the taxpayer is being appropriately remunerated for the billions of the dollars invested in Muskrat Falls. But that's a political question, right? So.

MR. SMITH: Okay.

Just to follow up. Looking at, if you will, the Energy Plan – can I have 00029, please?

Page 8?

Hmm, appears to be blank. Okay. Just a second now.

Yes, there. That's fine. Thank you.

THE COMMISSIONER: So, it's page 7?

MR. SMITH: It must be a situation of the red numbers and the black numbers coming in conflict.

You'll note in the Energy Plan of the Government of Newfoundland and Labrador 2007, they refer to, in the, I guess, the third paragraph that you can see on the screen, we have developed – okay? "We have developed" the "Energy Plan with our eyes … on 2041, when the Upper Churchill contract expires and the province is in the position to receive the full benefit from this resource. Between now and 2041, we will carefully plan and make decisions, not only to ensure Upper Churchill success in the future, but also to maximize benefits from our current and future resource developments, including Hibernia, Terra Nova, White Rose, Hebron," and "other … natural gas developments, the Lower Churchill, Voisey's Bay," and "wind developments, and refining and processing opportunities."

The issue is that it appears that even in the infancy of the Energy Plan and the development or the idea to develop the Lower Churchill, there was an interrelationship between their various resources to – you know, to deal with energy which the plan says in the previous paragraph is "an essential part of our lives." It seems to – and I don't know if it does to you or not, but it's seems to suggest that at the very earliest time, they were looking at all of the energy, if you will, issues in the province as a – as a single development, you know, as a single strategy I should say – not necessarily a single development, but a single strategy for the benefit of the province and the taxpayer and ratepayers, together.

Do you have any reason to suggest otherwise –

MR. COLAIACOVO: Hmm**.**

MR. SMITH: – in your research of the project?

MR. COLAIACOVO: No. And in actual fact – so, I had the privilege of meeting Mr. Martin and hearing him give speeches in Ontario during this period, 2007, 2008, 2009 where, in fact, this issue was discussed – about, you know, Labrador being an energy storehouse and about being able to recycle profits from the oil resources into investments in long-term assets like hydroelectric plants and so on.

And knowing all of that thought had been out there, I was somewhat surprised to not find this discussion in the actual documents that are pertaining directly to the Muskrat Falls plan such as the documents that were provided to the regulator in the regulatory process where these exact kinds of statements are not to be found.

MR. SMITH: Okay. They're not found –

MR. COLAIACOVO: In the right –

MR. SMITH: – but they're – you know, based on your exposure to Mr. Martin, that essentially was his view of why this project is a positive project for the province.

MR. COLAIACOVO: Well, certainly –

MR. SMITH: (Inaudible) value.

MR. COLAIACOVO: Yeah, certainly there was lots of commentary in his speeches about how all of these projects should be understood together because they're interrelated.

MR. SMITH: Okay.

MR. COLAIACOVO: And so Muskrat Falls, by that logic, is interrelated with Churchill Falls and all the rest. It has strategic value. And I agree it does have strategic value. But that was not offered as a justification, publicly, for pursuing Muskrat Falls.

MR. SMITH: When you say "publicly," you mean as part of the DG3 analysis?

MR. COLAIACOVO: That's right.

MR. SMITH: Okay.

Now, looking at page 25 of your report – we go back to 04445, please. Looking at page 25, your – you indicate – you reference Romaine, that's a hydroelectric project in Quebec.

And at line – excuse me – line 6, I think – yes, line 6: "In 2009, Hydro Quebec broke ground on its 1550" – excuse me – "MW La Romaine complex of hydroelectric plants …." Now, my understanding is that four or five plants were built along the river –

MR. COLAIACOVO: That's right.

MR. SMITH: – and together they –

MR. COLAIACOVO: (Inaudible.)

MR. SMITH: – come up with a – about 1,550 megawatts of power.

MR. COLAIACOVO: That's right, yeah.

MR. SMITH: Okay.

"These facilities were primarily developed in order to serve the export market …." I'm wondering, do you know if there's any export, firm contracts for the sale of Romaine power?

MR. COLAIACOVO: My – well, there are no – Quebec has no contracts that are associated with specific assets.

MR. SMITH: Okay.

MR. COLAIACOVO: All of their contracts are system contracts, so they can guarantee their firm power on the basis of their entire system, not – they don't associate a contract with a specific plant.

MR. SMITH: Okay.

I just was a bit confused. And I'd ask you to look at P-00255, page 14.

This is the Strategic Plan for Hydro-Québec between 2009 and 2013. Okay, and go to 14 – page 14, please.

Yes, right – no – the next (inaudible) – that – I think that's it. Excuse me, my bifocals don't work as well as they used to. That's page 13. Could you try 14 just – yes, scroll down a little. Yes, here it is.

Looking at this chart, okay, which is the strategic plan for Quebec from 2009 to 2013 – or actually goes out to '17, okay, it's the plan that was developed in 2009 to '13. They note that the additional capacity required as of 2016-17 and 2013-14, the additional capacity required was 700 megawatts in '13, '14 and 1,500 megawatts in '16, '17 which suggests, I submit to you, that building a 1,560-megawatt power project – Romaine – would be just to service their deficit, their – what's it called – the capacity deficit.

MR. COLAIACOVO: It actually wouldn't because that would presume that Romaine is operating at 100 per cent capacity when required. It wouldn't. They were already long on energy at this point and Romaine added to their excess energy.

MR. SMITH: Yep.

MR. COLAIACOVO: The capacity is a different issue –

MR. SMITH: Right.

MR. COLAIACOVO: – and at this time, they were actually already negotiating with – negotiating at the time with Ontario for a nuclear capacity trade so that they could get some winter capacity assistance from Ontario in exchange for summer energy because the two provinces have opposite peaks.

The issue around their energy and their capacity is somewhat mixed. But they also, in this charge, there's 3,000 megawatts of reserves that are also taken out in here, too. So their – and the other pieces, at this point, they were still expecting substantial expansion and load.

If you fast-forward a little bit to the next plan after this one, you'll see that, in fact, the picture has changed already somewhat. But, nonetheless, their – when they commenced on the Romaine project, yes, they were in need of capacity, but the Romaine project is really more about the energy that it provides and that energy is largely for export.

MR. SMITH: Are you suggesting, then, that they would sell their energy when they don't have enough capacity to meet their peak loads?

MR. COLAIACOVO: No, but they buy and sell constantly. I mean, their energy trading is non-stop. So I mean they're fairly sophisticated when it comes to valuing the resources that they have and what to do with them.

MR. SMITH: Could you read the small paragraph above the table, please, out loud?

MR. COLAIACOVO: Mm-hmm.

MR. SMITH: Could you read that out to the record, please?

MR. COLAIACOVO: Sure.

"As well as meeting energy needs, Hydro-Québec distribution must ensure that it meets the capacity requirements of its customers, which peak in the winter. The division's capacity supplies portfolio consists of the following …."

MR. SMITH: Okay.

Now, of that – quote, unquote – heritage pool that they refer to in the first section, do you understand that to include Churchill Falls?

MR. COLAIACOVO: No, I – I'm not sure that they do include Churchill Falls in their heritage pool. I believe the heritage pool is limited to just Hydro-Québec. So, I mean, they have a separate listing of contracted facilities. And the contracted facilities include Churchill Falls.

MR. SMITH: I'll just point out to you, my understanding is that the heritage pool includes about 3,000 megawatts from Churchill.

MR. COLAIACOVO: In the capacity calculation.

MR. SMITH: Yeah, in their capacity calculations.

MR. COLAIACOVO: I stand to be corrected.

MR. SMITH: Okay.

So, at this point in time when 2016-17 was being projected, they had a 1,580-megawatt deficit. And about the same amount that they received from Churchill is a reserve of about 3,100 megawatts. So one would assume, at this point, that the capacity that's missing – and there's a clear difference between energy and capacity. Capacity is what they require on the coldest day of the winter.

MR. COLAIACOVO: Right.

MR. SMITH: Essentially, okay?

Now, I looked at this – I don't know if you have, but it appears you have seen this before. I don't see any reference to exporting power from Romaine – La Romaine.

MR. COLAIACOVO: So –

MR. SMITH: Is there any reason for that, do you think?

MR. COLAIACOVO: There is a – I'm not sure if it's this plan or if it's the one that comes before or the one that comes after. I referenced it in my report, where there is a discussion about the Romaine project. And, you know, the discussion is about building Romaine and exporting the energy from – that it increases their capacity to export energy.

MR. SMITH: Okay, but they're increasing energy – or, sorry, exporting energy –

MR. COLAIACOVO: That's right.

MR. SMITH: – which is if we don't need it.

MR. COLAIACOVO: That's right.

MR. SMITH: In other words, if we need it for our capacity –

MR. COLAIACOVO: Right.

MR. SMITH: – right, then they won't actually sell it?

MR. COLAIACOVO: Most of Hydro-Québec's export contracts are summer.

MR. SMITH: Okay.

MR. COLAIACOVO: Their – because New York and New England, their primary export markets are summer peaking.

MR. SMITH: Okay.

MR. COLAIACOVO: So – which tends to work perfectly for Quebec, because they are a winter-peaking market. And so, they export heavily in the summer and export less in the winter.

MR. SMITH: So if Newfoundland were trying to rely upon export to keep Newfoundlanders warm in the – with light, okay – to coin a phrase – they would require a firm power commitment –

MR. COLAIACOVO: That's correct.

MR. SMITH: – from Quebec Hydro, correct?

MR. COLAIACOVO: That's correct.

MR. SMITH: Right.

And based upon this analysis or that what – their strategic plan, Quebec, even in this timeline, were short on capacity for themselves, and it would be difficult or impossible for them to sell firm power to Newfoundland, correct?

MR. COLAIACOVO: In the mid-2000s Hydro-Québec had identified that they were short, winter-peaking capacity, and that was when, you know, they started looking at a whole range of different options. Romaine was one. A negotiated deal – well, at the time they built a 600-megawatt interconnect with Ontario near

Ottawa so that they could buy more power from Ontario at winter peak and sell more power into Ontario in the summertime. None of that stopped them from continuously seeking export contracts, however.

So, yes, in the mid-2000s they had identified a capacity problem, but they were still very, very active in the export markets. And had it been remotely realistic for Newfoundland to have a commercial discussion with Quebec about power, they would have had that discussion; they would've found a way. But, you know, as I've said previously, I don't think that was realistic anyway.

MR. SMITH: Okay.

Yes, I understood that you felt that that was not a realistic option. However, it's been suggested at this Commission that we should've explored the option of getting – buying power. But there's no firm power to be had in the time frame 2011-12 – '10.

MR. COLAIACOVO: Yeah, I'm not – I – this was the 2009 plan which was prepared in 2008. I'm not sure if you go to the next plan after this whether the tone is quite the same.

MR. SMITH: Okay.

MR. COLAIACOVO: Because this would've been written before the recession kicked in.

MR. SMITH: Okay.

MR. COLAIACOVO: Right?

MR. SMITH: Could we have 04468, please?

Just first refer – this is a – the strategic plan for '16-20 – 2016-20. And if you turn to page 5, please? You'll see that at page 5 the phraseology shows that our power output of over 99 per cent of which is from clean renewable sources is: an essential component in the fight against climate change undertaken by the Quebec government. It's the cornerstone of a greener, stronger economy. Our residential rates are the lowest in North America. They're half the rates people pay in Toronto and a fourth of what people pay in New York.

Turn to page 9, please? To – okay. We need more capacity during peak periods. This is the 2016 to – whatever '19. Quebec capacity needs will increase over the next 15 years, driven mainly by the growth in residential demand. That's why we want to reduce our costly imports by having the TransCanada Énergie generating station in Bécancour converted to a liquefied natural gas and using it as a peaking plant.

Though new energy efficiency programs and initiatives, we can – through those new energy and efficiency programs, we can also shave up to 1,000 megawatts from the peak capacity needs forecast for 2020. The additional capacity requirements will be met through calls for tenders.

So it appears that the capacity problem hasn't gone away in Quebec, that they are indeed still having a capacity issue. And importing power – it turns out that they're importing power from New York.

MR. COLAIACOVO: Mostly from Ontario I believe actually. But –

MR. SMITH: Okay.

MR. COLAIACOVO: – the – Quebec's issue is largely of their own making. The province is heated – I think the number is 86 per cent – by electric baseboard heaters, which are wildly inefficient. But since they offer a domestic price that is so low, it encourages people to stay on that technology, as opposed to using natural gas or heat pumps or anything else.

So, they're continually struggling with continued growth and residential demand. Having said that, they've given no indication that their problem is unmanageable, and they're treating it in a relatively orderly fashion.

MR. SMITH: Right.

MR. COLAIACOVO: Again – and they admit in this document that they are well long energy – you're correct that they continue to have capacity issues, which is why they continue to build assets (inaudible) –

MR. SMITH: And with capacity issues, firm contract sales are not indicated.

MR. COLAIACOVO: Yeah, wintertime firm contracts.

MR. SMITH: (Inaudible.)

MR. COLAIACOVO: Summertime firm contracts are fine.

MR. SMITH: Right.

But firm contracts for the year –

MR. COLAIACOVO: Right.

MR. SMITH: – okay? And now that we live in Newfoundland, and if you've had a taste of it the last few days you've been here, we require heat even in midsummer, right?

MR. COLAIACOVO: The – yes.

So, the size of contract that would have been contemplated – and I think where you're going is: in 2010 or 2011 or 2012, the size of contract that would've been required would've been a 500 megawatts, right?

For Quebec to handle 500 megawatts of firm power for nine months of the year would have been no problem at all. For the three months in January, February and March, it would've stretched or squeezed their capacity margins that much more.

MR. SMITH: Okay.

MR. COLAIACOVO: Which would have led them to charge a high price for that firm capacity. Not that they could've possibly have done it, but they would have charged premium price for it, which is why I agreed with the analysis that Nalcor had put forward that there was no reason to believe that they would offer a reasonable or low price for that kind of capacity.

MR. SMITH: Okay.

Okay.

And if, for some reason, Quebec – Hydro-Québec did not have access to Churchill power – from Upper Churchill, the capacity deficit would be significantly greater, would it not?

MR. COLAIACOVO: Again, I'm deferring to the fact that you said that the 3,000 megawatts of Churchill is included in the heritage pool.

I think it's reasonable to believe that Quebec is preparing for 2041 to not require that power.

MR. SMITH: Okay.

Now if I could turn to my final topic for you. I'm looking at the suggestion that you make in page 4 of the executive summary, I think. It's – so we go to – back to 04445, please.

It starts at line 7: "From the record of information reviewed, it is clear that there" is "an insufficient basis upon which to make a determination of" the "least cost of available alternatives, on a risk-adjusted basis. This does not mean that the conclusion was not possible, only that it does not appear it could have been credibly arrived at given the analysis" that was "completed."

So you're not saying that the same result may be – it may even be likely – if the analysis was conducted as you suggest. Is that –

MR. COLAIACOVO: That's right.

MR. SMITH: Right, okay.

And at page 70 where you talk – you pick up this topic again, I'm interested in – at page 70 and picking it up at – scroll down a little bit, "There is no question." Okay.

At 14 – line 14: "There is no question" that "the dataset was grossly incomplete"

I'm curious as to why it was necessary to use "grossly incomplete" because if it's incomplete, it's incomplete. And to say it's "grossly incomplete" seems a little bit hyperbolistic.

MR. COLAIACOVO: The reference scenario is one scenario. Twelve sensitivities were run in 2012 for the December decision.

By my count there should have been at least 281 scenarios –

MR. SMITH: Okay.

MR. COLAIACOVO: – that were tested. So 12 out of – or 13 out of 281 justifies a bit of hyperbole.

MR. SMITH: It's still incomplete. To say it's grossly incomplete – now one of the sensitivities or at least two of the sensitivities, I understand, were run by MHI. You're aware of that?

MR. COLAIACOVO: Manitoba Hydro International.

MR. SMITH: Yeah. Manitoba Hydro – or, sorry, Manitoba Hydro International. MHI.

Could we turn, for a moment, Madam Clerk, to 00048 at pages 85 to 92?

Okay. Now, you can see here that Manitoba Hydro run a sensitivity analysis, and if you scroll down you'll see that there were several scenarios looked at. And they – in addition, at 00058, Manitoba Hydro in October of 2012, just prior to sanction, ran another sensitivity analysis, okay? And at page 75 they, again, ran another sensitivity analysis between the two options and the difference that would – and examined the fuel price as expected, low or high. Do you recall what the – Nalcor used for the PIRA fuel price?

MR. COLAIACOVO: These are the same sensitivities.

MR. SMITH: Yup. I understand. But I'm just wondering, do you recall whether or not they – when they actually chose which of the PIRA recommendations were taken, which one they took?

MR. COLAIACOVO: Well there was a reference, and a high and a low in PIRA's report.

MR. SMITH: Yes.

MR. COLAIACOVO: So they ran the sensitivities on the reference, they also ran the sensitivities on both the high and the low.

MR. SMITH: Okay. And which one did they choose for the purposes of the comparison?

THE COMMISSIONER: You mean Nalcor chose?

MR. SMITH: Yeah, Nalcor chose.

THE COMMISSIONER: Okay.

MR. SMITH: Sorry.

MR. COLAIACOVO: The reference scenario used PIRA's reference price.

MR. SMITH: PIRA's reference price.

MR. COLAIACOVO: Yeah.

MR. SMITH: And page 83, were the recommendations of MHI.

Okay, let's keep going, no down. Yeah, right there, MHI recommends. "Given the analysis that MHI has conducted, based upon the data and reports provided by Nalcor, MHI recommends that Nalcor pursue the Interconnected Island option as the least cost alternative to meet the future generation requirements, to meet the expected electrical load in Newfoundland and Labrador."

So MHI conducted the sensitivity analysis. It wasn't Nalcor conducting the sensitivity analysis, so if your criticism was that there should've been 200 and whatever sensitivity analysis, isn't that a criticism of MHI?

MR. COLAIACOVO: Well, Nalcor provided the sensitivities in the first place in 2010 – or I think 2011, sorry, I keep saying 2010.

MR. SMITH: Yeah.

MR. COLAIACOVO: The first set of sensitivities that were provided came in Nalcor's original report and then additional sensitivities were through – asked by the regulator and by intervenors. MHI was working for the regulator in that process. They were an expert witness for the regulator; and so they asked for some additional sensitivities and scenarios in that process.

When they came back and did this report, they were working with a refreshed set of sensitivities because the earlier process has been done on

2010 discounted dollars. The later process had been updated from 2010 discounted dollars to 2012. There had been an updated PIRA report and updated reports from a number of the other forecasters, so they reran the models – the CPW models and the sensitivities. And so MHI took all of that new information and produced this report. But the sensitivities – the CPW models themselves were prepared by Nalcor. MHI was reviewing all of those. I got copies of the same ones – the CPW models that were used at the time.

MR. SMITH: But I'm concerned though, as to whether or not MHI being asked, I believe at this time, by government to ascertain whether the Muskrat Falls Project was the least-cost option or otherwise, MHI chose, really, to do the sensitivities in the manner it did, as we indicated up on page 75. So I'm wondering where the disconnect is between your theory as to 248 scenarios as opposed to –

MR. COLAIACOVO: So –

MR. SMITH: – Muskrat – sorry, Manitoba Hydro, who chose to do it once and made a recommendation to Nalcor.

MR. COLAIACOVO: – what I find curious is that Manitoba Hydro, in the NFAT process, which came about a year after this, themselves ran quite a few scenarios. They started with 81 when they first presented their report, and then developed even more after that. In this instance, in that list that you pointed to just a minute ago, there was only less than 10. There was only about a dozen that were prepared in the Nalcor process.

So Manitoba Hydro itself – now this was Manitoba Hydro International, which is the consulting arm of that company as opposed to the corporate arm of the company. But they didn't follow their own consulting arm's practice because they did a heck of a lot more when they ran their own NFAT process –

MR. SMITH: And you've had access to these?

MR. COLAIACOVO: I worked on the NFAT process –

MR. SMITH: Okay. Yes, but not related to Muskrat Falls**.** That's a different project.

MR. COLAIACOVO: That's right.

MR. SMITH: Yeah.

MR. COLAIACOVO: But on this – on Muskrat Falls, I was given copies of the sensitivities and the CPW models that were prepared by Nalcor at the time, and those would've been shared with MHI at the same time.

MR. SMITH: So why couldn't government and Nalcor rely upon MHI, their experts and analysis of this material? They've done it one of your projects that you were involved with and they've done it here. Why can't Nalcor rely upon the MHI process?

MR. COLAIACOVO: So a system planner making decisions about a long-term system plan typically follows a fairly exhaustive process. The examples aren't just in Manitoba. BC Hydro has system plans; Hydro-Québec has system plans. In Ontario, there are system plans dating back to 2005. There are lots of examples of system plans, and they're quite comprehensive and quite detailed and go into great depth on analysis of different kinds of options and scenarios. What I am suggesting is not atypical; it just was not followed here.

MR. SMITH: Okay.

You also, in your report, seemed to – and I'm paraphrasing a little bit – said that if there were more data-set scenarios thoroughly analyzed, it would have been beneficial, but most would have favoured Muskrat, the Interconnected, even with trouble spots that might be – come out in analysis, and Muskrat would be still favoured on the lowest cost, or at least – or at the best or worst – equal cost with the Isolated Island. So it appears that no matter how many of these things you ran, at some point in time, you had to have somebody or somebodies make a decision.

MR. COLAIACOVO: That's been my point all along.

MR. SMITH: Okay.

MR. COLAIACOVO: No plan will ever be the best option – quote, unquote – in a hundred per cent of scenarios.

MR. SMITH: Okay.

MR. COLAIACOVO: But nonetheless, you still have to do the work of analysing the scenarios and understanding what the proportions are and, to the best of your ability, what the probabilities are that you're going to fall on one side of the line or the other and then the consequences of what happens, depending on where the world ends up going.

MR. SMITH: Now, one final point. When you did your analysis on highest and lowest oil price, did you consider the exchange rate?

MR. COLAIACOVO: That was done by PIRA, actually, so PIRA, when they did their analysis and provided their reports, they based it on sort of the global oil price, which is in US dollars, and they put in an assumption about the Canadian dollar. And then you also get a differential spread between, you know, market price and getting a number 6 heavy fuel in Newfoundland.

So all of those figures were included in the actual CPW models. I didn't have to do that. They were already there.

MR. SMITH: So would you agree with me that a difference between US$90 at 2012 and – I think it's $65 now, US, okay, that the gap between 2012 dollars on the exchange rate versus the exchange rate for today's $65 is not that huge a difference.

MR. COLAIACOVO: Yeah. I think I did a rough estimate that in 2012 real dollar terms – what PIRA provided was actually a long-term curve, which they discounted back and said, on average, in 2012 dollar terms, that low forecast is 37 per cent less than reference. And if you look at actual prices since then, the difference from their reference is approximately 43 per cent or so. So, I mean, their low forecast was not quite as low as prices have actually fallen, but it's pretty close. And I – you know, I have a lot of sympathy for forecasters who are asked to prepare highs and lows because they're held to account. But all that is, is it's a representative of a low future.

MR. SMITH: Yeah.

MR. COLAIACOVO: And so a 37 per cent low is a reasonable low for them to put in.

MR. SMITH: But I don't think I need to be that complicated. I just wanted to see, you know, with the exchange rate at 2012, which I understand was at par, or near par, and exchange rate at US$65 today, which is 30-odd-cents –

MR. COLAIACOVO: Right.

MR. SMITH: – difference.

MR. COLAIACOVO: And seven years of inflation.

MR. SMITH: And seven years of inflation.

MR. COLAIACOVO: Yeah, so when you add them all up together, their low forecast is not quite as low as the price today, but it's not that far off.

MR. SMITH: Okay, thank you so much. Thank you, Commissioner.

THE COMMISSIONER: Thank you.

All right, Nalcor Energy.

We're going to go to 4:30 today, so maybe you could guide yourself accordingly, maybe do one topic or something and we'll end at 4:30. And I only say that because tomorrow – our witness is flying in actually tonight on the late flight, so he's asked not to be in until tomorrow afternoon, so that's why we will have the morning tomorrow.

MR. SIMMONS: We will have time, okay. Thank you, Commissioner.

THE COMMISSIONER: Okay.

MR. SIMMONS: Good afternoon. Dan Simmons for Nalcor Energy, and I don't think I need to introduce who Nalcor Energy is. I think everyone is aware of that. I'm going to apologize at the start for maybe not being very well-organized in questions because they're going to perhaps be a little bit haphazard. You've addressed quite a few topics and I may bounce around a little bit as I do that.

So my first question just has to do with your retainer and the information available to you. You were asked if you'd been following some of the testimony of the Commission. Were you – have you been retained since the Commission began hearings, or did that happen at some point since September of last year?

MR. COLAIACOVO: No, my retainer was signed in February.

MR. SIMMONS: Okay, all right.

So I take it then that prior to that, you wouldn't have followed live any of the testimony as it occurred.

MR. COLAIACOVO: No, I did not.

MR. SIMMONS: And I'm presuming you haven't gone back and watched recorded testimony to any extent?

MR. COLAIACOVO: I did not watch any testimony. I selectively went back and looked at some of the written reports.

MR. SIMMONS: Right.

MR. COLAIACOVO: But I didn't watch any live.

MR. SIMMONS: Right.

And for the information that you had available for preparation of your report, I know that there were no requests that came from you through to Nalcor to provide anything because they would've come through us. So I'm presuming that you relied and had – you relied on and had available information that was provided to you by Commission counsel and Commission staff?

MR. COLAIACOVO: That's correct.

MR. SIMMONS: Right.

So that would've been drawn from the information that's been produced to them or selected by them to provide to you.

MR. COLAIACOVO: Yeah, at the time that I was retained, it was 1,365 or almost 1,400 documents.

MR. SIMMONS: Right.

MR. COLAIACOVO: In addition, I was provided some confidential documents –

MR. SIMMONS: Yes.

MR. COLAIACOVO: – which I made use of but did not quote from or publish –

MR. SIMMONS: Right.

MR. COLAIACOVO: – in the report.

MR. SIMMONS: And I presume – or you can answer this. Maybe I'm presuming wrong. The information that you were provided, was it limited to the documents that had been made exhibits, either public or confidential, at the hearing, or were you also provided with other information – modelling information, Excel spreadsheets, scenarios and so on – from the Commission?

MR. COLAIACOVO: No. I – it – well, I think the – none of the confidential information as exhibits I –

MR. SIMMONS: Well they're –

MR. COLAIACOVO: – I'm not certain (inaudible) –

MR. SIMMONS: – confidential exhibits not available to us – to the rest of us.

MR. COLAIACOVO: But I don't believe so.

MR. SIMMONS: Nalcor has produced five-million-plus documents to the Commission. So you – did you have access to the database of the complete collection of documents and information or only to those that have been made exhibits in the hearing?

MR. COLAIACOVO: Principally, I believe they're just what was made exhibits –

MR. SIMMONS: Exhibits, okay.

MR. COLAIACOVO: – except as – again, as I – I'm not sure whether some of the confidential documents were exhibits or not.

MR. SIMMONS: So, then, your – the conclusions that you've stated or the statements that you've made about the extent to which scenarios were run using Strategist has been based on the information available to you perhaps from some selective evidence that you've looked at and from the documents that have been made exhibits as opposed to the entire body of material produced.

MR. COLAIACOVO: So I reviewed all of the documents that have been made exhibits – painful –

MR. SIMMONS: Yes.

MR. COLAIACOVO: – as that was – in addition to the documents that I was provided confidentially.

MR. SIMMONS: Okay, okay. Good. Thank you.

You've been careful in your report and in your evidence, I think, to recognize that there's a danger of hindsight bias in reviewing decisions, and complicated decisions, that have been made in the past. And we're looking back here at a decision, essentially, that was made in 2012, which is seven years ago, now, with quite a bit of water under the bridge since then. And we know, now, where the project is, and there are current assessments of what the impacts are on the interests of ratepayers and taxpayers in this province.

Can you – and this may be challenging to ask you – but can you give me some sort of assessment as to what extent you think the views you have expressed in your report and on the stand may have been unavoidably affected by hindsight bias based on what you know about what's actually happened?

MR. COLAIACOVO: I think I've tried to be very clear –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – about the areas where I think you can't help but recognize bias. So, for example, in talking about technology change –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – things have changed even in just the last seven years.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: And so looking back and saying: Should that have been a bigger possible concern?

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: Right? Should that have been analyzed more? You know, those – and well, I mean, I don't – the oil price is an obvious one, but I'm putting a lot at caveats around that.

MR. SIMMONS: Yes –

MR. COLAIACOVO: And as I've said –

MR. SIMMONS: – and I recognize that.

MR. COLAIACOVO: – I thought PIRA's cases were entirely reasonable.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: Given what they were.

So, I mean, as I said, I don't think anyone can be entirely free of bias –

MR. SIMMONS: Mmm.

MR. COLAIACOVO: – but I have been at pains to put myself into the shoes of 2012 –

MR. SIMMONS: Right.

MR. COLAIACOVO: – in trying to come to some conclusion.

MR. SIMMONS: To take the technological change as an example. It's – I'm going to suggest that it's very difficult to separate yourself from knowledge that since 2012 there has been technological change, and has continued to be. To separate yourself from that knowledge when you go back and put yourself in the positions of the people who are conducting the assessments in 2012 and say: I'm going to limit my thinking only to what they knew at the time, based on what they knew up until then.

MR. COLAIACOVO: On the other hand –

MR. SIMMONS: Yes?

MR. COLAIACOVO: – if you look, for example, at Ontario's system planning documents from 2005, 2007 and 2010 –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – where there was an analysis of different kinds of technology portfolios.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: There are graphics that you'll find in either the documents themselves or the appendices that are attached to them later –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – which look at the cost per megawatt hour for wind over time starting in 2000 and declining.

MR. SIMMONS: Yes.

MR. COLAIACOVO: Or the prices for solar panels and declining.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: Or, you know, the efficiency of gas turbines.

You do find, even in the historical record, at the time, recognition in different places about technology change.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: It's obviously progressed a lot more since then, but there was progress even at that point, right?

MR. SIMMONS: Right.

MR. COLAIACOVO: And so, you know, is there a discussion in the public documents about technology change? And how that was taken into account in the planning process –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – in the construction of the options for the system.

MR. SIMMONS: Right, okay. Good.

Thank you.

This is where I'm going to start to bounce around a little bit on some of the issues, and you may have answered this question to a large extent already.

We've heard a fair bit of testimony, in this phase of the Inquiry, regarding the fact that a cost-of-service approach was used for the rate setting on the LIL, the Labrador-Island Link; and that the PPA, Power Purchase Agreement, approach was used for the Muskrat Falls plant and the Labrador Transmission Assets, which as you've said, fixed a long-term price that escalated at 2 per cent to basically match inflation. So it was meant to be a flat price over –

MR. COLAIACOVO: Mm-hmm.

MR. SIMMONS: – a period of time. And some of the questioning that has been – questions that have been asked of witnesses here have been critical in one way or another over one choice or the other.

So I'm going to ask you: Is there anything in your experience where there is any kind of inherent advantage or disadvantage of one approach over the other, or do they each have their own advantages and disadvantages which have to be considered?

MR. COLAIACOVO: A cost-of-service approach has, for decades, been the standard model for regulated utilities where assets are fungible and numerous; whereas a PPA approach has typically been followed for assets that are small in number or singular, unique. Because the cost-of-service approach inherently is front-end loaded, the economics of the cost-of-service approach has high cost at the front end and declines over time as investors receive their return of capital.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: If you have many assets, if you're a distribution system with lots of poles and lots of transformers that are replaced frequently, right? Then you don't – you have a relatively smooth capital expenditure, a relatively smooth return on capital over time. So cost of service is fine because cost of service applied to any individual asset will be lumpy. But when you have lots of assets it's – it actually ends up being fairly smooth. But where you have a single large facility, cost of service is difficult for ratepayers to swallow because it is front-end loaded.

PPA, on the other hand, can either be – typically either be structured as a flat price or as a price that escalates with inflation. And so, from that perspective, a PPA can be easier for ratepayers to handle over time. There's a sense of fairness with a PPA that –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – you know, if it's going up with inflation, then everybody is paying their fair share.

MR. SIMMONS: Right.

MR. COLAIACOVO: The unique aspect of the Muskrat Falls PPA, though, is that not only is the price inflating over time, the quantity is inflating over time. That's different from most PPAs.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: A PPA that is signed for a wind farm, for example, if it's a 100-megawatt or a 200-megawatt wind farm, it produces that much power in the first year and it keeps producing the same amount –

MR. SIMMONS: Right.

MR. COLAIACOVO: – of power, give or take.

MR. SIMMONS: So under the PPA, in dollar terms, if we were to consider the number of dollars that had to be paid per year, under the PPA from, ultimately, Newfoundland Hydro, Newfoundland and Labrador Hydro, because the amount of power that was projected to be drawn increases over time, the number of dollars paid per year also increased over time.

MR. COLAIACOVO: Correct.

MR. SIMMONS: And by a greater factor than just the 2 per cent inflation rate. So if that were the only mechanism used to pay for the project, there might be an argument that there was intergenerational inequity because the later generations are paying more for the project than the earlier.

And my suggestion is, and I'll just finish the thought, is that because the cost-of-service approach was used for the transmission assets, which moved more of the recovery of the cost to the earlier stages of the project, in this scenario, the cost-of-service approach, the way it was structured and the PPA approach the way it was structured tended to balance each other and balance the intergenerational effects over the period in which they were in effect.

MR. COLAIACOVO: There's – there is some truth to that, if the load projection was accurate.

MR. SIMMONS: Right, and we're back in 2012 remember –

MR. COLAIACOVO: Yes.

MR. SIMMONS: – 'cause we're not using hindsight, we're only looking at it –

MR. COLAIACOVO: Right.

MR. SIMMONS: – from 2012.

MR. COLAIACOVO: Absolutely. But there – the PPA, as structured, places a very heavy burden on the accuracy of the load projection.

MR. SIMMONS: Yes.

MR. COLAIACOVO: It's a risk.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: Right? And the burden of that risk lies with ratepayers, because it's a take-or-pay contract.

MR. SIMMONS: Mm-hmm.

And is the cost-of-service approach as applied here for the LIL not the same?

MR. COLAIACOVO: It's exactly the same.

MR. SIMMONS: Right.

MR. COLAIACOVO: Absolutely.

MR. SIMMONS: Right, yeah.

MR. COLAIACOVO: And –

MR. SIMMONS: And –

MR. COLAIACOVO: – by no means am I suggesting the cost of service is a better approach.

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: Right? The – I – there was a discussion earlier about why the cost of service, and it had to do – I think in part – in large part with Emera's participation and so on and so forth. But the – the cost-of-service approach for the Labrador-Island Link is, I guess – well, both of them are sensitive to the issue of load, because the transmission is going to be distributed across more or less megawatt –

MR. SIMMONS: Right.

MR. COLAIACOVO: – hours consumed, either, as well.

MR. SIMMONS: Sure, sure. But the load sensitivity of the Power Purchase Arrangements and the cost-of-service agreement, I'm going to suggest that does not change the fact that the two of them put together helped cancel out the intergenerational effects.

MR. COLAIACOVO: Within the 50 –

MR. SIMMONS: So that –

MR. COLAIACOVO: – years –

MR. SIMMONS: – to put together –

MR. COLAIACOVO: Yeah.

MR. SIMMONS: – regardless of whether the load forecast –

MR. COLAIACOVO: Right.

MR. SIMMONS: – was accurate or not.

MR. COLAIACOVO: No, that's correct.

MR. SIMMONS: They did smooth it over the period of time in which they were both in effect.

MR. COLAIACOVO: To some degree, yeah.

MR. SIMMONS: Yes, okay.

MR. COLAIACOVO: You have to kind of work it out on a per megawatt hour basis –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – to see how much –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: – that actually – that they – how much they do actually cancel each other out.

MR. SIMMONS: So let us say –

MR. COLAIACOVO: But the tendency is there.

MR. SIMMONS: – if the potential for intergenerational effects from this large project built – intended to be in use for a long period of time and paid for over a long period of time, if those intergenerational effects had been recognized in the planning, this concept of using partly cost of service and partly PPA could be viewed as a response to that and as a mitigation of the potential intergenerational effects. Yeah?

MR. COLAIACOVO: When you look at the CPW calculation in nominal-dollar terms, that what you actually see there is a net price that is increasing very slightly over time is my recollection –

MR. SIMMONS: Mm-hmm.

MR. COLAIACOVO: It's from in my report that –

MR. SIMMONS: Right.

MR. COLAIACOVO: And that actually shows the effect that that cancellation that you're –

MR. SIMMONS: Right.

MR. COLAIACOVO: – talking about.

MR. SIMMONS: That's the effect.

MR. COLAIACOVO: So on – in nominal-dollar terms there's only a slight increase on a per megawatt hour basis.

MR. SIMMONS: Good, thank you.

Commissioner, it's 4:30, so that might be a suitable place to break.

THE COMMISSIONER: It's a good place for you to break?

MR. SIMMONS: Yes, it is.

THE COMMISSIONER: Okay, so – thank you.

So we'll adjourn until tomorrow morning. I think we will start at 9 o'clock tomorrow morning just to make sure we do finish because we have – the next witness is going to take more than a day as well.

Okay, so we're adjourned until tomorrow morning at 9.

CLERK: All rise.

This Commission of Inquiry is concluded for the day.