IN THE MATTER OF THE JOINT REVIEW PANEL ("JOINT PANEL")

ESTABLISHED TO REVIEW THE SITE C CLEAN ENERGY PROJECT

("PROJECT") PROPOSED BY BRITISH COLUMBIA HYDRO

AND POWER AUTHORITY ("BC HYDRO")

CANADA ENVIRONMENTAL ASSESSMENT AGENCY

AND

BRITISH COLUMBIA ENVIRONMENTAL ASSESSMENT OFFICE

PROCEEDINGS AT HEARING

Questions focused on the need for, purpose of,

and assumptions about the alternatives

Responses to Undertakings

January 23, 2014

Volume 28

Pages 1 to 211

C o p y

Held at:

Pomeroy Hotel - Scott Pomeroy Ballroom
11308 Alaska Road
Fort St. John, British Columbia

APPEARANCES

JOINT REVIEW PANEL:

Dr. Harry Swain - Chairman
Ms. Jocelyne Beaudet
Mr. Jim Mattison

Brian Wallace, Esq. (Legal Counsel)

THE SECRETARIAT:

Courtney Trevis (panel Co-Manager)
Brian Murphy (panel Co-Manager)

PARTICIPANTS:

Craig Godsoe, Esq., BC Hydro (Legal Counsel)
Peter Feldberg, Esq., BC Hydro (Legal Counsel)
Ms. Bridget Gilbride, BC Hydro (Legal Counsel)

REALTIME COURT REPORTING:

Mainland Reporting Services, Inc.

Nancy Nielsen, RPR, CSR(A), RCR
Diane Huggins, OCR

AUDIO/SOUND SYSTEM:

AVW-TELAV Audio Visual Solutions

Alex Barbour.
Technical Services Representative.

INDEX OF PROCEEDINGS

INDEX OF UNDERTAKINGS

Thursday, January 23rd, 2014

Fort St. John, British Columbia.

(Proceedings commenced at 9:00 a.m.)

Introductory Remarks by the Chair:

THE CHAIRMAN: Good morning, everybody. We are returning to where we started in December with questions focused mostly on the need for and the purpose of and the assumptions about the alternatives to and so on, for this project.

And at last, it's the panel's day. We have half a dozen questions that we've asked BC Hydro to answer, and we invited interested parties to let us know what questions they would like us to ask.

Here's how we're going to proceed today.

First, BC Hydro will answer the six questions we gave them at Halfway River on January 7th. If we need clarification of the answers, we'll ask.

Following our invitation to participants, we have prepared 19 additional questions. We have not simply parroted the questions posed by interested parties, but we have read and considered every one of them to help us determine what additional information might be material to our mandate to assess and make recommendations on the

environmental, economic, social, health, and heritage effects of the Site C project.

All of these 25 questions have been posted on our website; although, the final 19 went up only this morning. Some problems with connectivity at Blueberry River. All 25 will be on the screen as we go through this.

After we have finished the discussion of those 25 questions, Hydro will then have the opportunity to answer any questions it believes to remain outstanding that have arisen during the public hearing.

If, during the course of the day, you think there is a question for BC Hydro, the answer to which would materially assist the panel in its conclusions or recommendations, please, give it to Mr. Wallace, the gentleman who looks like Le Corbusier over there with those glasses, please give it to him in writing or speak to him at a break.

Ms. Yurkovich.

BC HYDRO PANEL:

Susan Yurkovich.

David Ince.

Randy Reimann.

Chris O'Riley.

Mike Savidant.

Opening remarks by BC Hydro:

MS. SUSAN YURKOVICH: Thank you, Mr. Chairman. Good morning, panel members. Good morning to those who have joined us here today.

I am joined today by our needs, purpose, and alternatives panel that appeared before you in December, including Mr. David Ince, our manager of market forecasting, and Mr. Randy Reimann, who is our director of resource planning, and Mr. Savidant, our commercial manager who is familiar to you at this stage of the process.

I am also joined by my colleague, Chris O'Riley. And Chris is the executive vice-president at BC Hydro who is responsible for our generation assets and operations, as well as energy planning. And because some of the questions that the panel has posed overlap with how we reliably operate the system. I have asked him to be here today to speak to a number of the questions.

At the session at Halfway River on January 7, you provided us with six questions where you asked

for additional information. You were very clear to us that you did not want to add to the already very large volume of materials. And we took that to heart, and, as such, we have prepared a PowerPoint presentation that you have today, and that will help us to respond to your request.

If I could ask for the first slide to go up. Mr. Chair, we have noted them.

Sorry, can you go to the next slide, Danielle.

We have noted them in order. In fact, as you read the transcript number 2, actually, has three parts to it, and, with your permission, we would like to go through them largely in order, but leaving question 3 to the end, if possible.

THE CHAIRMAN: That's fine.

MS. SUSAN YURKOVICH: Thank you.

I'd note that this panel will also be available to answer other questions, and we've also made arrangements to have many of our other subject matter experts available should they need to respond to something the panel has as an outstanding question. And for those who were not able to travel here today, we can have them available on teleconference.

Just before we begin our presentation, I want to quickly provide this response to the question we had at Blueberry River First Nation yesterday with respect to taxation.

There was a question about respect to PST being applied to a Blueberry River First Nation's hydro bill, and we have checked with our colleagues in our customer care group and understand the following:

That generally residential customers should be PST exempt should Indian Bands on reserve land or unincorporated business owned by a Status Indian provide that the documentation has been provided.

Having said that, we understand that under the ***Provincial Sales Tax Act***, there are some circumstances where PST will be charged.

So for the person that asked the question, we would need to look at the specific account details. We absolutely will undertake to do that following our day today, we'll follow-up directly to make sure that that matter is cleared up.

THE CHAIRMAN: Thank you.

I'm surprised that the Province thinks that it can tax on reserves.

MS. SUSAN YURKOVICH: Well, we'll get to the bottom

of it, sir.

THE CHAIRMAN: Good.

MS. SUSAN YURKOVICH: Thank you.

So I would now like to turn the presentation over to Mr. Reimann and Mr. O'Riley, who will provide our responses to the panel.

Thank you.

Presentation by Mr. Randy Reimann, BC Hydro:

MR. RANDY REIMANN: Thank you, Susan. Good morning.

The first two slides go to the questions about the relationship between population growth and the load forecast growth. And I kind of want to just walk through some of the key relationships, and then look a bit historically how things have evolved. And I think that's quite informative of what we see going on in the Province.

In this first slide, what we're showing is that -- next to historical load, so the billing data, there -- here are shown for the three load forecast segments the key drivers.

And starting with the residential side, the key drivers, pretty much of equal importance, are housing starts, personal income, and end use

information and saturation rates.

And certainly housing starts are related to population, and we do see a general relationship to population.

But in the industrial and commercial, the next most important factor that drives the growth is gross domestic product.

And so -- and, particularly, I guess with the large industrial, we wanted to point out that we do go through an account-by-account forecast. We've got key account managers that have good relationships with the customers and they go through and try to understand business plans. We have sector forecasts that are done for us. And we take all of this detailed information to go through really a customer-by-customer estimation for those large accounts. And I think those large accounts account for about 40 percent of our energy.

Next slide.

So on this graph, we tried to explore, then, what those relationships are between both growth GDP population and the load forecast, so it's showing 40 years of history and then the 20-year forecast.

The red line shows the gross domestic

product. The green line -- and the colours maybe -- could be more differentiated, but it starts on the top left, and then it goes off towards the bottom right, is population growth.

And then the blue line shows the load growth; historically, you can see the 2008/'09 recession.

And then in the current 20-year view, the dotted blue line shows load growth before DSM. And the solid blue line shows expected load growth after DSM.

So what this shows us, and I guess what we've experienced in the past is there are times when the growth in the Province moves quicker than population, and I think you see that for a lot of the previous 40 years up until the recession. These are times, I guess, when the Province is becoming more prosperous and the industrial load is growing.

So there are times, then, you can see in the early 40 years where that load growth is outpacing the population growth. And these are really times when the Province is becoming wealthier and more prosperous as the industrial sector grows.

And so we do see periods of fast growth. And then particularly with the 2008/'09 recession,

there are periods where it slows down.

Looking out over the next 20 years, and, in particular, the next 10, again, we see that load growth, this is before DSM, is pretty much matching or getting close to matching what the GDP forecasts are. And we're seeing the large industrial load growth attributable mainly to the mining development in the Province and the oil and gas, and, particularly, the gas development. And those are probably the two key factors that are moving us somewhat faster than on average.

And so once we do the demand-side management, that does pull the forecast down to track more with population. And I guess we see that there's a bit of an inflection point, if there is one, when we start committing to the large DSM target, and we're trying to pull down the load growth and that shifted it a bit away from tracking GDP. Our sense in the longer term, GDP is the key driver.

I also wanted to mention that the GDP and population forecasts that we get in the shorter term is the Ministry of Finance. And in the longer term, we use Stokes and Stats Can to forecast those out.

So we would be happy if there's any -- to

take any questions, if anything in detail, David would be happy to answer them. But if not, we could keep rolling.

Okay.

Next slide. You're already there. Thank you.

This slide is trying to get to the questions about the elasticity and some of the back-of-the-envelope calculations and how those might have been different than what -- or to understand how they relate to the elasticity that we calculated.

And so I just wanted to point out that the -- we covered some of this material in the JRP IR26S and the further information, request one, and in undertaking 1. And what we'd pointed out is that our method of elasticity calculation and the way we determine the imputed elasticity was based on a log map that -- and using a logarithm method is something that is an industry standard, and, in particular, when you're doing time series analysis and looking for correlations to do future forecast estimation. And it's our understanding and belief that when you see a lot of the work out in the industry that is trying to determine elasticity

relationships, that they follow a similar sort of logarithm formula calculation.

And so to get at some of the differences that you might see, depending on how you apply these, so what we did in the table was looked at how you would go about calculating the elasticity with a logarithm based on a percentage based.

And so we looked at the load forecast in three steps: 2012, 2022, and 2033. And so the logarithm-based calculation of elasticity, that was the imputed elasticity after DSM effects. And what it was intended to do was to say -- the DSM programs are really taking us from the 72,000 down to a sixty-one six.

And to get from a -- in the second column from the 50,000 starting point to a 61, given the price increases and original load forecast, what was that imputed elasticity? If you calculate that with the logarithm-based method, you get the -.57.

What we find is that you get different results if you use the percentage-based type calculation, and so we've done the same thing in the right column.

THE CHAIRMAN: Excuse me. Are you applying elasticity only to the incremental load?

MR. RANDY REIMANN: No, it was to the total load. It was just how to apply that elasticity to get down to that total load point.

And so if you do the percentage-based calculation, you end up with a different elasticity.

And, again, it's our experience and belief that the logarithm-based is the -- is sort of the industry standard and the proper way to do it.

And so what ends up happening, if you take the logarithm-based imputed elasticity, and you then try to go out ten years and you see what the numbers are, you do come up with a number in the order of 55,000. You could do the same thing with the percentage-based one if you used that imputed elasticity and do a calculation out ten years, you'd get to a similar number.

I think where we need to be careful is if you do the logarithm-based imputed elasticity and then try to replicate the ten-year results using the simplified formula, you do then end up with about a 2,000 gigawatt hour difference.

THE CHAIRMAN: Hydro is going by the classic economics textbook definition of elasticity, and economists can't handle logarithms, as you know.

MR. RANDY REIMANN: Okay. Next slide.

This slide was to address the question about where the capacity requirements that we see earlier in the 2020s are showing up relative to the energy. And, really, the short answer is is that it's due to the smaller capacity contribution that we get from intermittent IPPs.

And so when we do our load resource balances over the 20-, 30-year period, what's included in that? So we've got the load forecast, we've got our existing and committed supply, we have a DSM target and IPP renewals. And then from there, we started looking at adding additional resources. So this was the basis of determining the gap.

And so what we did, just to demonstrate where the capacity requirements are coming from is looking at the energy and capacity, and then we did a simple capacity-to-energy ratio of megawatts to gigawatt hours just to show the relative contribution.

And so what you see for the load forecast is a ratio of .18. And we see that as being pretty constant over the full period of the load forecast, so there's nothing really changing there.

On the existing and committed supply, not

surprisingly, we target that to meet the load requirement, so we need the right ratio of energy to capacity. It has the same number.

The DSM target, given that our DSM programs are broad in trying to hit all areas, we find that the capacity contribution from it that we're hoping; albeit, it's large, is a -- is very close to what a normal load ratio would be at the .17.

But when you look at the IPP renewals -- and this is that relative to the energy contribution -- the dependable capacity or the contribution that these make to the system from a capacity perspective is quite a bit less.

And so when you add that into our load resource balance with a ratio of .10, that's where you now start seeing that there's a need for capacity sooner than there's a need for energy.

THE CHAIRMAN: I'm sorry, Ms. Yurkovich, you were suggesting that we go through all of the questions before we --

MS. SUSAN YURKOVICH: No, Mr. Chair. I'm just trying to make sure that we've addressed your question before we move along, so whatever you would like.

THE CHAIRMAN: No. I was -- I'm perfectly

willing to accommodate you, but if we want to do this question-by-question, I want to go back a step, then.

MS. SUSAN YURKOVICH: Okay.

THE CHAIRMAN: To your slide -- whatever it was. The one before that.

On the industrial side, the information -- an important source of information is what you get from your account managers. Historically, how good has that been as a predictor?

Presentation by Mr. David Ince, BC Hydro:

MR. DAVID INCE: Good morning, Chair. David Ince, on the load forecast.

They are dealing with the customers, our key account managers are dealing with the larger industrial customers on a regular basis.

THE CHAIRMAN: Yes.

MR. DAVID INCE: And so they'll be talking about the production outlook.

Our industrial forecast is done looking at the production forecast, multiplied by an intensity. So how much energy is used to produce, let's say, a certain amount of tonnes of ore or amount of pulp.

And so it -- they are looking at a production outlook, but also tempering that with our information with respect to the industry, commodity prices. We try and be very -- I guess a sober analysis in terms of -- particularly, some customers, like the mining customers and their expansion plans, we have to make sure that we temper optimistic expectations with some sense of reality.

THE CHAIRMAN: Yes. And you have the problem of, you know, they are on or they are off, it tends to be big lumps and so on.

MR. DAVID INCE: Indeed.

THE CHAIRMAN: But when you say you temper this stuff with intensity with sectorial forecasts from third party sources and so on. I'm still curious, the account managers in many businesses are often the people who have really a pretty good sense of what's going on. And considering them alone as a source of information, how good are they?

MR. DAVID INCE: A lot of our account managers have expertise in the specific industry, so we have people on the oil and gas side who have experience in the actual industry itself, or people in the

pulp and paper side who have been with the facilities. And they are a very good source of information.

But, again, we have consultants on each of the sectors. So, for example, we have pulp and paper consultants, forestry consultants, mining consultants, and we assemble all this information together with the economic indicators to combine that, to come up with, I think an informed forecast on 220 individual customers.

MR. RANDY REIMANN: Yeah. I think the -- probably the short answer is is that -- and the exact percentage, I'm not sure we could quote, but we've tracked pretty well the relationships that the key account managers have, what the accounts often allows us to have some inside information of what's likely to come down the road, things that we can't actually put out into the public because it's privileged, and it might really impact financial health.

THE CHAIRMAN: Okay. Now, particularly, the field reports will tend to get a little vague when you get off there 10 or 20 years into the future. Your industrial forecasting must produce a kind of an array of forecasts for 2032 or something; right?

MR. DAVID INCE: If you mean an array in terms of -- there's different sectors.

When you look at the GDP forecast, for example, we just can't apply that on every sector. Every sector has a characteristic in terms of their health such as gold prices, wood prices and so on.

THE CHAIRMAN: Yes, but those -- when they are on a sub-sectorial basis or an aggregate basis, you're going to have a cloud of uncertainty that grows as you get farther forward into the future. It's only natural.

MR. DAVID INCE: Absolutely. The industrial forecast is more uncertain, yes.

THE CHAIRMAN: So what number do you choose for your forecast? Is it the middle of the cloud? Is it the 90th decile? What is it?

MR. DAVID INCE: One of the key principles of the forecast is we try not to bias it. So it's P50 forecast. That's what we endeavour for. So, hopefully, my legacy will be that 20 years for now --

THE CHAIRMAN: Closer to your mic.

MR. DAVID INCE: Hopefully, my legacy will be that 50 percent of the time, my forecasts would have been too high and 50 percent too low, so with

no intention of bias.

THE CHAIRMAN: That's perfection. Okay.

I'm not sure quite where --

MR. RANDY REIMANN: If I could add to what David was saying, is we do do a P10 and a P90 calculation of our loads and of the expected DSM delivery, and that is when you see the portfolio analysis of our low growth or a high growth scenario, or a low or high gap, that is based on taking these forecast segments and doing a P10, P90 assessment.

MR. MATTISON: Just a question.

I know, for instance, in the residential, we know there's a day and a nighttime load that's quite different, and there's also seasonal loads that change. How does industry change seasonally and even daily or weekly? Are there swings in the load -- I'm not thinking now of long-term forecasts, I'm looking in year.

MR. DAVID INCE: The load across the year for the industrial customers is relatively flat. We see that with all the sectors that I can think of; they are trying to run flat out basically --

MR. RANDY REIMANN: And if there is a bit of seasonal in there, it's just that in the wintertime, in colder temperatures, some of the

processes take more energy to operate and that would be the biggest difference.

THE CHAIRMAN: Okay. On that, I'm now on to your page 7. Over to you.

MS. YURKOVICH: Go ahead.

Presentation by Mr. Chris O'Riley, BC Hydro:

MR. CHRIS O'RILEY: Thank you, Mr. Chair.

So the panel requested information on the revenue requirements of the project, including key inputs to that, the amortization and such. And what that would mean in terms of a rate increase when the project comes into service. And that's an important consideration for capital projects because they do have a significant rate impact.

I should qualify this: the BCUC will ultimately determine how the costs are recovered from ratepayers in the future, and that would occur in a revenue-requirement process covering the period when the asset comes into service, but there are some general approaches which we've reflected in these calculations and some principles.

So we have undertaken a project-specific revenue requirement and rate analysis, and it's included in the table on the chart. And you can

see the asset coming into service in fiscal 2024. And you can see the various categories of amortization, finance, operating costs, which include water rentals.

And then there's a netting off of sales of surplus energy. So that's energy that's being sold into the external market, and that leaves a total. And that total line would go in our revenue requirements, in our budget, and it would be used to calculate the rates.

And I'll start and talk a bit about the amortization because you asked a specific question about that.

The amortization is really -- comes from the accounting. And the principle is we amortize the component over its expected life. And when you hear the 70-year weighted average, what that is, it's a dollar-weighted average of the various components of the asset.

So we've done an analysis in our estimating group where we looked at the different components, and we compared that to our experience. And, for example, the dam is in the calculation at 80 years, so with the civil assets and such. 80.

And then other assets like the other

components, like the turbines and generator are in it at 45 years. And that roof of the powerhouse, for example, is in at 25 years.

So when you weigh those all together, it comes out -- it actually comes out to 71.2 years. And so we've approximated the 70 years.

And I would say that's consistent. You know, if we look up the river to Bennett dam and the powerhouse, those kind of expected lives are consistent with what we're experiencing with our existing assets.

So if we turn -- yeah, I should say one more point. If you go beyond the four-year period we've shown in this chart, what happens is the surplus sales tend to go down as the load grows, and these costs end up being spread over a larger base in the system.

THE CHAIRMAN: Your assumption on finance charges, these are all real dollars, of course, 2013?

MR. CHRIS O'RILEY: These calculations are done in nominal dollars, and I'll stand to be corrected --

THE CHAIRMAN: Oh, nominal?

MR. CHRIS O'RILEY: -- on that.

But that's what -- when you do rate -- when you're doing a rate impact calculation, like in this case, we need to do that in nominal dollars. And Mr. Savidant may correct me here.

THE CHAIRMAN: So, if nominal, what's the forecast? What rates are you using?

MR. MIKE SAVIDANT: Sorry, what financing rates? Our long-term costs of debt is expected to be just under 5 percent. I think it's something like 4.82. That's recently decreased from 4.95 when I believe we did the analysis for this, this was 4.95 percent.

THE CHAIRMAN: How long can you lock in a rate like that?

MR. MIKE SAVIDANT: Yeah. We manage it not on a project basis, but on an overall portfolio of debt.

So when our treasurer goes out and finds debt, he creates what he thinks is the best balance between short-term and long-term debt of varying tenors.

Generally, you see the longest term debt that I believe we have in our portfolio right now, and subject to check, is, roughly, 30 to -- 30 to 40 years. I believe 30 years is my recollection, but I believe we were looking at potentially

getting some longer term.

THE CHAIRMAN: I'm sorry, I can't hear you. 30 and 40 years and what.

MR. MIKE SAVIDANT: Sorry.

THE CHAIRMAN: Between 30 and 40 years, and what --

MR. MIKE SAVIDANT: 30 to 40-year debt is the longest term debt we have in our portfolio.

I know we have a 30-year debt in our portfolio, and I believe we've been looking at some longer term stuff as well.

THE CHAIRMAN: What are you paying for 30-year debt?

MS. SUSAN YURKOVICH: We will check with some friends at the back of the room and get that to you.

THE CHAIRMAN: Okay.

Kind of an interesting question because if you're running a 70- to 80-year amortization on chunks of this stuff, the assumptions that you make about future inflation when you're dealing with nominal debt are hugely important. So what are you assuming?

MR. CHRIS O'RILEY: Well, I would say, generally, when we're doing -- looking at portfolios like

this, we're talking about real dollars. And you'll see a chart in the handout that shows the revenue requirement over time, and that is done in real dollars.

You asked -- the panel asked the question about the rate impact when it comes into service. That has to be done in nominal dollars.

THE CHAIRMAN: Yes, I understand.

MR. CHRIS O'RILEY: This is an unusual calculation.

THE CHAIRMAN: I mean, one can do rate calculations in real dollars, but the custom is not to do that, so I was interested that you said that these are nominal dollars in this chart.

MR. MIKE SAVIDANT: Sorry, Mr. Chair, I've been handed a document.

So on what our -- we've recently completed a triple-A price debt issue at 3.25 percent for a 30-year debt.

THE CHAIRMAN: That's an attractive number; isn't it?

Now, what are you going to do about the next half century after that?

MR. MIKE SAVIDANT: This is why we finance on a portfolio basis across.

THE CHAIRMAN: Yes, I know you finance on a portfolio basis, all corporations do.

MR. MIKE SAVIDANT: Yeah.

THE CHAIRMAN: But you have an asset here, which you are depreciating over a very long period of time, which you are financing over a very long period of time. And so the assumptions for the out years become interesting in terms of inflation.

Is historical experience useful here? Could we have another 1980?

I guess the real question is how do you conceive of the risk of interest rate excursions in the period beyond current finance ability?

MR. CHRIS O'RILEY: That's a great question.

I think what we do in the -- first of all, in the comparisons, the portfolio comparisons, is we look at present value, which kind of drops off the back end of the value and the costs.

You can certainly have interest rate excursions, and we've seen them, you know, throughout history. If you take a long view of history, hundreds of years, and decades, even, we have interest rate excursions.

I think the two points to consider here, when you get beyond the 30-year window, which is what we

can lock in, and we have been locking in through the government, 30-year money, the benefit here is half the -- by 30-year point, half of the costs of the plant have been amortized down, and you're looking at a much smaller base.

THE CHAIRMAN: Right. I mean, half of 8 billion is chicken feed, I agree.

MR. CHRIS O'RILEY: Yeah.

THE CHAIRMAN: That's a bit of a cheap shot.

MR. CHRIS O'RILEY: Yeah.

THE CHAIRMAN: But it is an interesting point.

MR. CHRIS O'RILEY: Yeah. I mean, we do have this problem generally because half of 8 billion is 4 billion --

THE CHAIRMAN: Yeah.

MR. CHRIS O'RILEY: -- which is two years of our general capital plan. So we have a financing challenge in general, and so we have to be very careful with interest rates.

THE CHAIRMAN: Well, I have to say that the panel has refrained from asking questions about what bankers would classically call the financial condition of BC Hydro because it's not directly relevant. And also because it's an artifact of

provincial policy more than good accounting practice, I think.

The real question, though, is the entanglement of Hydro with the Province. And Mr. Savidant just said that -- did a 3.25 over 30 with a triple-A rating. Unless the Province is pretty sharp at managing its increasing debt load, there is a danger that triple-A could become double-A and so on.

The cost implication of one notch might be 20 basic points, something like that.

In your calculations, thinking now as -- of yourself as a corporation rather than as an arm of the BC government, have you examined the consequences for corporate finance of -- and for rate requirements and so on -- of a loss of a notch or two in the BC credit rating?

MR. CHRIS O'RILEY: So we have looked at different scenarios for financing cost. We've not explicitly speculated, I don't think, or considered the changes in the government's credit rating, but we've looked at changes in the interest rates, which you could attribute to a change in the government --

THE CHAIRMAN: To anything you wanted

without being charged with lèse-majesté.

MR. CHRIS O'RILEY: Pardon?

THE CHAIRMAN: Would you contribute to anything you wanted without being charged with lèse-majesté.

MR. CHRIS O'RILEY: Exactly. Exactly.

THE CHAIRMAN: Yeah.

Now, there's a number here for surplus sales, again, nominal, but -- and I notice we have a diagram coming later of prices that are -- as it were, market prices, but those do seem, to me, to be pretty large numbers that you can -- you know, that you can -- in the early years that you can flog a substantial part of the output of Site C for an amount of money, which is a very appreciable part of your total costs.

Now, what are the assumptions about power prices in years 24, five, six, and so on.

MR. CHRIS O'RILEY: We were -- we have an intention to come on to that on slide 11. Would you like to go there now, or would you prefer to --

THE CHAIRMAN: Yes, while we're on the topic, let's have a look at that.

MR. CHRIS O'RILEY: Okay. Sure.

So the portfolio modelling in the EIS and in

our IRP takes into account the surplus that's expected, and the range of surplus given different scenarios for load. And it effectively balances the surplus by selling it in the market. And so we use different price scenarios, and these are the three scenarios and the weightings that we use in the portfolios.

So, for example, the base case here really is a 35-dollar per megawatt hour --

THE CHAIRMAN: Okay, these are real or nominal? Real, I suppose.

MR. CHRIS O'RILEY: These are real. So you can see they are in 2013 dollars.

MR. DAVID INCE: And I should add that those are yearly average values, so that -- these are year average values, so there will certainly be seasonality. Freshet prices will be quite a bit lower.

THE CHAIRMAN: Okay. All right. Let's carry on.

MR. CHRIS O'RILEY: So perhaps we'll go back to slide 8, and here we talk about the rate impact as it -- as the asset comes into service.

And I want to say, first, there's been a number of -- well, a couple changes that have

occurred relating to the government November 26th announcement. So the government changed how return on equity was calculated, and they had this concept of deemed equity and a percentage return on deemed equity, so it wasn't real equity. And it was a bit of a cash machine --

THE CHAIRMAN: Yes, the question of your real equity is one of the great mysteries of --

MR. CHRIS O'RILEY: Yes. It's a whole other question, which I'm happy to get into, but ...

The other thing they did is they eliminated the third tier of water rentals, and that was a particular water rental that was paid only by BC Hydro.

THE CHAIRMAN: I'm aware of that, and that accounts for one of the further questions, but I didn't pick up the November 26th announcement. Thank you.

MR. CHRIS O'RILEY: Yeah. Yeah.

So this transition I think in about 2018. And after 2018, what they are going to do is have the income, the return to the Province go up at about -- at inflation.

So they've actually reduced the amount of money they are taking out of BC Hydro, and,

consequently, from the ratepayers. And that was just a recognition that it was too much. There was just too much going across the -- across the water.

MR. MATTISON: Mr. O'Riley, when you say "reduce the amount of money," reducing both the dividend and the water rentals? Or it's a mix of both of those payments? Is that correct?

MR. CHRIS O'RILEY: Yeah. Well, it's -- they did both. And I would distinguish. They actually -- there's the calculation of that income, which goes into our revenue requirement, and then there's a portion of that which is the dividend. They also reduced the dividend, which has a debt reduction benefit for us, so -- I didn't mention that, but that's really a third change.

And there's two implications of that: one is it's reduced our forecast load rate increases in general, takes a significant weight off the company.

And in the 2012 load forecasts, we had a 33 percent increase in rates over a 20-year window. And based on the announcement in November 26th, that figure is now 21. And, again, these are real. So that's great.

And it also has a very beneficial impact for

Site C's revenue requirement because of the way that the deemed equity would have been counted and we would have paid the third-tier water rentals on Site C.

And there is a handout in the set of slides that you were given that shows the revenue requirement over time. And it's broken down by the different components. And you can see that the dashed line is what the revenue requirement would have been before these changes were made.

MR. MIKE SAVIDANT: That -- that's handout 4.

MR. CHRIS O'RILEY: Yes, Danielle, thank you.

So it takes more than $100 million out of the revenue requirement for the first year as the asset goes into service, so a significant reduction. And, again, these are real dollars, so we go back and forth.

THE CHAIRMAN: So it's not -- you'll have some real equity by 2024 in a responsible calculation?

MR. CHRIS O'RILEY: Yes. The target in the company is some -- you know, through the reduction of dividends is to maintain that reduction until the equity -- debt equity reaches a 60/40 ratio, which we think is appropriate for the company. I

think, in general, the feeling has been it's been light, particularly given the capital plan.

THE CHAIRMAN: But one way to put this is that a change in policy by the government of BC has reduced the annual cost of service by, I don't know, 15 or 20 percent, it looks like?

MR. CHRIS O'RILEY: Yes. And that -- those changes also flow on to our existing asset. So it's a very --

MR. CHAIRMAN: Yeah.

MR. CHRIS O'RILEY: -- very important change. And we were very, very happy that they agreed to this.

Those recommendations --

THE CHAIRMAN: So the interesting question is does that cascade through all of the calculations of UECs and so on for the project and for its alternatives?

MR. CHRIS O'RILEY: It actually does not affect -- well, the water rental change affects the UEC because that's a variable cost.

THE CHAIRMAN: Yeah.

MR. CHRIS O'RILEY: The return on equity does not affect the UEC because it's -- the UECs are calculated based on a -- the capital cost divided

by the energy. So it -- it has about a dollar, I understand. The water rental change has about a dollar impact on the UEC.

It doesn't affect the alternate portfolios because they -- you know, the run-of-river, the IPP, hydro plants never paid the water rental; they always had the benefit of a lower water rental.

THE CHAIRMAN: Yeah. Yeah. Okay.

MR. CHRIS O'RILEY: So if we could go back to slide 8. And this -- so we have actions that have been taken, and then potential actions that could be taken. And this concept of rate-smoothing to really clip the peak of the initial revenue requirement as an asset comes into service, and we do that through a rate-smoothing regulatory account. So you would effectively under-recover for, say, the first five years of the asset; over-recover later.

And we did this in 2010 when we bought one-third of Waneta dam from Teck, and Fortis have used this technique when they brought assets into service recently. So it's a common utility technique to kind of smooth the blow, if you will, of large capital.

THE CHAIRMAN: It's a legitimate use of

deferral accounts.

MR. CHRIS O'RILEY: Yeah, absolutely.

So if we go to slide 9, and you can see the effect of this. And what we're showing here, again, is a project-specific rate impact in nominal dollars with and without the smoothing.

So if you look at the blue line, that's without smoothing. And you can see the initial rate impact -- cumulative rate impact peaks between 5 and 6 percent in fiscal 25.

And with smoothing, you can see the rate impact peaks at about 3 percent. And carries on at a constant rate through 2023. And you can see the over and the under, 33. Fiscal 2033.

And you can see the over and the under, which is the difference between the blue and the green lines.

The other point is that in both cases, the cumulative rate increase is below what it would otherwise be. It's actually negative when you get to 2034. And you've paid down that initial amount. And that's indicated by the fact that we're -- the cumulative rate increase is below the line.

And I just say two things. Again, the smoothing is very much subject to the commission

review and approval.

And I would also just say, as by comparison, we normally do these calculations on a comparative basis between portfolios because our job is to choose one portfolio over the other. So it's not one portfolio or nothing, it's one or the other. And we've shown, in the handout, the comparative rate impact calculation between the portfolio with Site C in it and the clean generation portfolio, if you have any questions about that.

And to interpret these, these charts, when you're above the line, that means that the clean generation portfolio has a higher rate impact. When you're below the line, it means the portfolio with Site C in it has a higher rate impact.

So the cumulative rate impact of the clean generation portfolio without Site C is much greater. And that's indicated by the high red or orange line there.

We've shown the effect of smoothing with or without. And that effect goes away after the 10 years because that's the term we've assumed for the smoothing.

THE CHAIRMAN: If you go back one to the blue and green --

MR. CHRIS O'RILEY: Slide 8, 9.
THE CHAIRMAN: Slide 9. The bottom line: a comparative rate analysis is provided in the CPCN filings. Are they going to do a CPCN judgment?
MR. CHRIS O'RILEY: Well, no --
THE CHAIRMAN: It's a rate hearing; is it not?
MR. CHRIS O'RILEY: No. What we're trying to make the point here is -- we're really just providing this information on slide 9 for your benefit.
THE CHAIRMAN: Yes, okay.
MR. CHRIS O'RILEY: Normally, in -- the CPCN guidelines ask us to do comparative rate impacts, which is what we would do in a CPCN if there were a CPCN.

So let's go, Ms. Melchoir, to slide 10.

So the panel asked the question about changes in the power markets since the 1980s, which was when our previous large -- our last large hydro plant came into service and generated a surplus. And the panel, I understand, wanted to talk about the financial risk implications associated with those differences in the market.

So I worked at Powerex for seven years. I

wasn't there in the '80s because I was in high school. But I was there from 1997 through 2004, so a period of a fair amount of development of the industry and we went through the California power crisis and all that.

But I have spoken to folks who were involved in trading electricity in the 1980s, so I have a sense -- we have a good sense of how that worked.

And what I would summarize, that the key differences between the '80s and today is all around the access that we have to markets and to customers because the transmission is now open, and utilities are required to make that available to third parties.

So in the '80s, we had to negotiate with bondable power as -- you know, to get to California. And it was very difficult to get to California. And expensive. And you had to kind of pay the toll on the way. And there were no -- there was not a regular --

THE CHAIRMAN: And the rewards turned out to be less than wonderful. Gosh, your timing was good, sir.

MR. CHRIS O'RILEY: Yeah.

So the other difference between the '80s and

today is there are a lot more products. We mostly sold these big block contracts, perhaps shaped seasonally, to utilities in California for multiple years. We have a lot more different markets, power pools, capacity markets, different products, peaking products, ramping products, regulation products, there's a lot more tools in our kit to market the power. And that doesn't really come through in the portfolio analysis. We're just looking at bulk energy prices as a proxy. So it is quite different today.

You asked, in particular, about, well, let's compare the prices. And we did have a go at that. We, unfortunately, don't have a lot of price history from the '80s because they were a different kind of product.

We have included in the handout -- and if Ms. Melchoir could go to that -- and it's a chart, a very busy chart -- right there -- that shows the spot prices in the pacific northwest, the daily prices for peak and off peak, going back to 1996, and that's when those -- that price visibility came to exist.

What I would say is the other big difference we have today relative to the '80s is -- comes

through in this chart, and it's the volatility.

And what we've learned is Powerex, our trading arm, actually make their money more off the volatility and the variability of the prices than the absolute value of the prices.

So Powerex has done well in the last decade or so in periods where prices were high and prices were low because they've become very adept at taking advantage of the variability and the ability to move price power around.

THE CHAIRMAN: Good.

Tell me what HLH and LLH mean.

MR. CHRIS O'RILEY: Yeah. HLH is a -- it's heavy load hours. It's a -- it's one of the many acronyms. And light load hours is LLH. So it's peak and off peak. And it's -- the HLH is two-thirds of the day, and the LLH is one-third of the day, overnight.

THE CHAIRMAN: Thank you.

Just from nowhere, what do you think is going to happen this summer with the loss of the 2,000 megawatts of nuclear in California? What's going to happen to prices?

MR. CHRIS O'RILEY: Yeah. So I'm a little ways a way from that, I probably shouldn't be speculating

on short-term markets. That was a -- that was a -- I think a Rube's game when I was at Powerex, let alone now that I'm so far away, but -- I mean, I think it's an issue of concern when you take that much capacity out of a market.

And, in general, the prices in the summer, you know, depend a lot on the weather and outages. And, I mean, it could -- it could be fine; it could be a challenge for the --

THE CHAIRMAN: Okay.

MR. CHRIS O'RILEY: -- and I -- what I -- I guess our traders kind of stand at the ready to help if there's a need for power. And ...

THE CHAIRMAN: Make sure they get paid in advance?

MR. CHRIS O'RILEY: Yes.

THE CHAIRMAN: Dealing with California.

Back to your slide 10, a regional shortage of dynamic capacity. Do you want to expand on that a bit?

MR. CHRIS O'RILEY: Yeah. Sure.

So what's happened in the market is there is more renewable capacity; there's more wind. And there's actually an increasing amount of solar in California. And the solar is interesting.

In many ways, it matches the load because the sun is out in the day. It is a real problem over the morning and the evening peak. And when you get people -- the sun goes down and you get people cooking and plugging in their electric cars and doing all the things they do when they get home, and I know in California they are very concerned about their ability to deal with the solar ramp. And so our folks -- our trading folks are working very hard to try and find a way for us to help.

And our capacity, our hydro capacity, including the existing capacity we have, and Site C, is perfectly suited to helping California deal with their ramping problem. And so we see that as a big opportunity.

There's also a challenge in the market. The wind in the northwest is clustered in the Columbia Gorge, and it tends to be either on or off, there's not a lot of diversity in the resource.

And Bonneville provide the short-term back-up for that wind through some tariffs that they have. And it's a very big challenge for them.

And their administrator, their effective CEO shared with us an internet chart, showing the output of the wind. And it turned off for weeks in

the -- in the summer, and also in the winter, you know, due to high-pressure zones. And people actually called in and said this internet site down, but, no, the wind was down.

So he is responding -- - Bonneville is responding to try and manage the regulation, and they have a limit on their capacity. So there have been opportunities for Powerex and BC Hydro through Powerex to take advantage of the opportunities that creates.

So we are finding that short-term ability to ramp up and ramp down is just becoming more and more value -- valuable.

And, again, the subtleties like that aren't reflected in our portfolio analysis, which, again, is just what you could get for the energy.

THE CHAIRMAN: So your non-firm hydro production from the heritage resources is increasingly valuable in export markets?

MR. CHRIS O'RILEY: No. I would say our firm exports and our ability to match load and generation is increasingly valuable. I would say our non-firm hydro is the opposite. And we'll come to that. We do intend to address that particular question later in the presentation.

THE CHAIRMAN: Just to register one other point, it seems to me that this fascinating discussion raises again the question of what on earth the government meant by self-sufficiency?

MR. CHRIS O'RILEY: Well, we'll come to that.

THE CHAIRMAN: Yes.

MR. CHRIS O'RILEY: So I think we're on slide 12. Thank you, Danielle.

So we turn now to the -- I missed that. We turn now to the question of self-sufficiency. And I -- the panel was asking for ways we could interpret that policy in ways that could give us more flexibility to time new resources.

And I should say, by way of background, we've had the self-sufficiency policy requirement for awhile. And it goes back to the 2007 energy plan.

And the origin of that policy was that the government's concern that our planning criteria, prior to 2007, resulted in a systemic reliance on imports.

And we had an explicit reliance of 2,500 gigawatt hours in our planning criteria, so for market imports. So we wouldn't acquire that generation in BC, we would just rely on the market for that.

We also had 6,000 gigawatt hours of reliance on Burrard for firm energy, which, for many years, has tended not to run, and we would end up just importing.

So the sum of that 8,500 gigawatt hours resulted in a systemic imports -- systemic reliance on imports into the system, even in a normal water year, and a much larger imports in a -- in a really low water year. And we had a number of those in the last decade.

So the self-sufficiency -- well -- and the government didn't like that. They didn't think that was a good foundation for running a system, an appropriate way to plan for a system.

So that the self-sufficiency at its kind of basic element is about having enough power in the system to meet the load. And that's not just capacity, but also energy. Because in a hydro system, you have to think about energy.

And that self-sufficiency is about having that capacity and energy in amounts and in products that you can rely upon.

And while it is a policy for us, it goes to the basic, our basic responsibility as a utility, which is meeting -- meeting the load.

And I should say -- and I note -- and I say this with the greatest of respect to my colleagues in transmission and distribution, within limits, an outage caused by transmission or a distribution problem is expected. And it's -- and really acceptable. And I understand that you had one of those not too long ago.

An outage or a curtailment due to a lack of generation is a different story. And it's generally considered to be a crisis and a really big problem. And we saw kind of an example of this very recently in Newfoundland where they didn't have enough generation because of a combination of one of their plants being down, and load growth. And they ended up with rolling blackouts. And the language around that was quite elevated, and the term "crisis" was used. And that falls back, ultimately, on governments. It hits the utility along the way, but it ultimately lands in governments. So that is why --

THE CHAIRMAN: And I know -- -- I notice we have a new Premier there, too.

MR. CHRIS O'RILEY: I did note that, as well. And there was a little bit of a connection, I understand.

So -- I mean, that is why utilities and regulators and governments spend so much time on planning criteria. It's very important. And there's a lot of thought that has gone into this.

So if we look at the -- the slide lists the key components of self-sufficiency. And the most important determination is the degree to which we can rely on the heritage hydro system for energy. It's probably the most important planning input that we have.

And the regulation says, as you know, the resource capability can be no more than what we can produce under average water.

And if you turn that around another way, it says what we do is we plan to rely on up to 4,100 gigawatt hours a year of imports above and beyond our critical -- critical water.

So the 4,100 compares to the 8,500 I talked about, historically, so it's a reduction in that.

THE CHAIRMAN: But, you know, one thing that troubles me a little bit about -- I think the -- that going to average water and relying on external markets, when you need to, is a sensible conclusion. But I'm thinking that it's demand more than energy that's driving the need for additions

to the system at the moment, at least in time.

And when you think about the demand curve, sort of the -- you know, that cumulative annual demand curve, you get -- I don't know. At the left-hand edge of the curve, you have hundreds of megawatts that you need for only 1 percent of the time.

And so the question of how you define self-sufficiency way off on the left-hand side of the curve is interesting. I mean, you would, presumably, be willing to pay quite a lot for demand that would be called on a few dozen hours a year.

MR. CHRIS O'RILEY: Yeah. Well, we'll come back because you asked specifically about that. So if you'll allow me to -- we'll come to that very point.

And I just -- I just want to say we need -- in the -- Site C is a long-term resource, and we need both energy and capacity. And you've -- you've seen the charts, and we've got them in here about the details around the timing, but I want to say we need -- we need both. And it's being driven by both. And we can talk about that some more in terms of the tactics.

Just to say one more thing, or a couple more things about the self-sufficiency based on average water. You're aware they came to this after the government review we had in 2011. It was actually a recommendation of BC Hydro. We thought it was an effective way to plan and operate the system.

And, for me, personally, it's the right -- I think we got to the right place on this calculation. It's a -- it's a good foundation for both planning the system and operating the system with an appropriate reliance is I think was your term, on external -- on external markets, so ...

And I think it was all -- it's in -- in this Province, it does get hotly debated, and there are a lot of perspectives back and forth. And I know the government, they hear from us, they also hear from stakeholders and experts, and there's a lot of people that have expressed opinions on this. And I would say the effect of that, it was an informed debate and a well-considered debate.

The next slide turns to the question of how we deal with this IPP non-firm. And this is really a hydro issue because of the -- well, we'll explain -- explain that.

And I think the suggestion I heard from your

questions was could we somehow firm this non-firm energy up and get some more credit for it in our, in our stack, in our load resource balance, and be able to defer new acquisitions? And --

THE CHAIRMAN: Well, specifically, to use your gas allowance for firming?

MR. CHRIS O'RILEY: Yes. And we'll specifically deal with that.

And what I want to say at the outset is we've actually, in our planning process, we've done what you're suggesting. And I'll explain -- explain that.

So when we -- we acquire these contracts through calls, and there's a firm amount bid in and a non-firm amount, and you can add up the amount of contracted firm that you have from all those individual contracts, and you can add up all the amount of non-firm that you can get. That is not how we make the determination of our reliance on firm.

We do that calculation on a portfolio basis, on an aggregation basis, taking into account the diversity among those contracts, and our ability to store and re-shape it with the system.

So we did that calculation in our IRP. And

the result is that 85 percent of the average run-of-river hydro IPP power is considered firm.

And that is more than what you would get -- significantly more than what you'd get by looking at the contracts on an individual basis.

And for comparison, our clean power call, which was our -- you know, had a lot of run-of-river hydro in it, 72 percent of the average generation in that call was -- was firm on a contracted basis.

So we're giving the benefit of the aggregation, the diversity in our system to this very important resource for us.

The other thing I would say is in the -- in this IRP process, we sharpened our pencil and were able to increase that determination, the firm amount, by 500 gigawatt hours per year, which is a couple percent on that 85 percent calculation. So I think we have pushed that.

If you look in the handout -- and I'll defer to Mr. Savidant on the number.

MR. MIKE SAVIDANT: Handout 8.

MR. CHRIS O'RILEY: This shows the profile of the run-of-river hydro over the year. And you can see that bulge in the middle, which is the freshet or

the spring energy, call it by various names. This data comes from the resource options report. So it's potential projects not actual projects. But the actual projects would be very similar to this.

And a lot of this non-firm hydro that we're talking about, the 15 percent that's kind of the balance that's left -- left over here occurs in the freshet. And it's very difficult for us to turn that into firm, to make better use of it.

And we're finding we're very close to the point where we can't absorb any more spring freshet energy into the system and use it and move it around from -- from year to year -- or from season to season.

And there are times when we're -- we end up spilling it or we end up selling it for very low prices. So it's a very tough resource for us to put more reliance on it, and -- and, really, that particular part of the supply is not that useful for running a utility. It's kind of a necessary by-product of the firm run-of-river, but it's more problem than a -- than a -- something of value.

So from a very practical operations view, that -- we're back to -- yes, so back to slide 13.

That's fine.

The very practical operations view, we don't have the ability to increase our reliance on this kind of seasonal non-firm hydro. And we'll get to it a little later, but a thermal plan, a single-cycle gas turbine doesn't help you move that energy from the spring to, say, the winter. It doesn't shape --

THE CHAIRMAN: No, but it can help with other sporadic resources?

MR. CHRIS O'RILEY: Yes. It provides its own benefits, but those benefits are completely independent of that energy we just talked about. So we'll -- and we'll talk about those benefits later on.

So that is the practical and operating view.

I would also say that if you go back to the self-sufficiency definition, we think relying on this non-firm and putting in our stack would be outside the policy. And it would effectively be increasing that 4,100 gigawatt hours and -- well, increasing that number because you're effectively going to be importing and replacing that energy because they can't use it for our system.

And, again, that was a subject of much consideration and debate and -- and in the IRP, in

the drafts we sent to the government, and the consultation and in the final decision.

So the next slide gets at the question of gas. And I think what you're saying is could we use the head room that we have in the 93 percent clean, could we be more aggressive in interpreting the self-sufficiency to defer investments, to defer commitments.

And I want to say, as a general comment, when we implement government policy, we do consider both the letter and the spirit of the policy. And there are times when the policy might not be as clear as we would like.

And what we do in those occasions is we have a lot of dialogue back and forth with the Province. And we confirm that we're aligned on where we want to land.

And this has been the approach we took on this issue of gas and self-sufficiency in the IRP.

THE CHAIRMAN: When those discussions take place, are they concluded with a letter or a minute or something --

MR. CHRIS O'RILEY: Yeah, sometimes --

THE CHAIRMAN: I'd like to know what it's about.

MR. CHRIS O'RILEY: Yeah, sometimes.

In this particular instance, they were formalized through the IRP, so we put a draft to the government in May 2012, we put -- and we got feedback. And they heard from folks. And we put another draft to them in August. And -- of 2013. And we did some more consultation. There was a lot of debate in the Province, and we got lots of feedback. And I'll talk about the specific feedback we did get. And then we put a final document forward.

So -- so these policy interpretations are made in the -- in this IRP. Like, they are confirmed. That's our view.

So we think the role of gas and self-sufficiency has been thoroughly explored. It's been documented in the 2013 IRP.

We also went through the experience of the 2008 process -- planning process at the BCUC, and I'm going to talk about that and how that unfolded. And we -- we got clarity by the government on the legislation after that. So I will come back to that.

So we --

THE CHAIRMAN: Just before you leave that.

The approval of the IRP in 2013 was when? November?

MR. CHRIS O'RILEY: It was -- it actually was announced November 26th, the same day as the rates. Yeah, it was approved by -- officially approved on November 25th through the order in council.

THE CHAIRMAN: Thank you.

MR. CHRIS O'RILEY: So in the IRP, we set out three ways to meet the 93 percent objective. And the first was the interpretation based on the critical water from the heritage hydro system. That was the way we did it under the old definition of self-sufficiency, and that was more strict, so we -- we didn't recommend that.

The second was aligned with planning based on average water is, and that was what was obviously recommended, it says there, and was approved.

And the third was to meet this 93 percent based on not counting the -- or discounting the amount of generation we're going to get from thermal plants, and relying on imports from the market to help us out in the 93 percent calculation. So that's what number 3 is.

So -- so putting in gas plants that rarely run and then having those displaced by market

imports and then showing that rate in the -- in the 93 percent calculation.

So, option 3, the challenge with that is it resulted in a systemic reliance on -- on self-sufficiency -- on imports, and undermined the concept of self-sufficiency. So you could meet the 93 percent, but you're failing over here on self-sufficiency.

And we are also concerned that -- I mean, there's a lot of fossil-based fuel in the generation in the U.S. Sure, there's some renewables. But we would be getting fossil-based imports. And, again, that would undermine the clean energy intent and spirit of the regulation.

So I would note that -- so we put all that in the IRP. We had lots of back-and-forth discussions.

What is interesting is the only feedback we got to change the IRP between August and November was to add in a section on clean energy, to develop a strategy that would support the clean energy sector. So there was no feedback to, well, let's do more thermal. There wasn't any feedback to, say, do more DSM. They were happy where we landed there, that the policy emphasis was on clean

energy, here in BC.

THE CHAIRMAN: And that's because the panel was otherwise occupied.

MR. CHRIS O'RILEY: Yeah.

So if we go --

MR. MATTISON: Mr. O' Riley --

MR. CHRIS O'RILEY: Sorry.

MR. MATTISON: -- I just want to back up to the statement you said about the reliance on the thermal energy imports. And, I mean, I just want to make sure I understood what you said about not burning natural gas but importing coal-fired electricity.

How did you move from that? Where did you go from that?

I mean, I understand they said more reliance on clean energy, but is that not still -- most of the market purchased energy is thermal purchased when it's cheap, if I understand the way Powerex trades thermal power from Alberta or somewhere where it's less costly --

MR. CHRIS O'RILEY: Yeah.

MR. MATTISON: -- it contributes to the bottom line, BC Hydro and the government, I suppose, but it contributes to greenhouse gas

emissions in a greater way than it would if generation was done from burning natural gas.

And I just want your comments on that, and how that -- I can't follow that into what you're just telling us.

MR. CHRIS O'RILEY: The change, yeah.

Well, the primary -- the primary consideration was that what they didn't want us to do was to put in single-cycle gas turbines that would tend not to run because of prices and carbon tax and the like, and then lead to imports because it goes against the spirit of -- of self-sufficiency.

I think they also recognized that if we did that, they've got these other objectives around climate change and reducing emissions, there would be emissions associated with those imports. We don't do a great job of tracking them or calculating them. It's hard. But there would be emissions associated with those imports.

And they weren't looking at the calculation between -- well, coal in Alberta versus gas here in BC; they were looking at coal and gas in the U.S., which is increasingly playing a role given prices, and renewables here in BC, so that, I think, was

the calculation.

And I just reiterate, the primary thing was the self-sufficiency policy, but I think the nature of the imports was also a factor.

And I do acknowledge the imports are a mix of -- I mean, there's lots of wind in there, there's freshet hydro, there's all kinds of things in the mix, but we think the GHG content of those emissions is much greater than the intensity here in BC. I think that's factual.

THE CHAIRMAN: Before we leave this I'm still confused about the rejection of single-cycle gas turbines. And I'm thinking of that load duration curve with its very narrow peak on the left-hand side of the diagram, and how that relates to the definition of self-sufficiency. In a -- in a strictly purist world, you would say that we would have -- we would have to have enough capacity on average to meet the -- you know, the last hour of high demand on a winter breakfast morning or whatever it is. And that's nonsense. That would be a very, very expensive way of doing it.

So to rely, if one can, on market imports for the very tippy peak of the thing would be fine.

If you're not allowed to do that for the

self-sufficiency criterion, then gas turbines that run a few dozen hours a year would seem to be attractive; particularly, if the alternative is bearing very large environmental costs.

MR. CHRIS O'RILEY: Yeah. And we are kind of going back and forth here between capacity and energy and firm energy. And --

THE CHAIRMAN: I'm thinking -- I'm thinking of your own tables, which show that we run out of capacity six, seven years before we reach the energy threshold.

MR. CHRIS O'RILEY: Yeah.

THE CHAIRMAN: And so, in my mind, that means that capacity is the most urgent thing that's facing you at the moment.

MR. CHRIS O'RILEY: Well, again, we think we need both. And we'll come -- come to that.

THE CHAIRMAN: But you need capacity first.

MR. CHRIS O'RILEY: Yes. And that's because we're renewing some IPP contracts, as Mr. Reimann said, that have lots of energy, but don't bring capacity in the --

THE CHAIRMAN: Well, we're going to come back to this business, but, so far, you haven't convinced me on the peaking power problem.

MR. CHRIS O'RILEY: Okay. Well, we -- I think the peaking -- well, we'll come back to the peaking power, because there's also the -- we have other hydro resources for capacity that, in our stack, come out first right ahead of the single cycle. So we'll come back -- we'll come back to that before we close.

I just want to -- if we go to slide 15, and I think it's important to just go through this experience we had with Burrard because I think it illuminates the -- the -- how we're thinking about this.

And this option 3, this reliance on -- kind of notional reliance on gas for energy -- and I'll put your question for capacity aside for the moment -- for firm energy here, was played out and tested in this 2008 planning process called the LTAP, long-term acquisition planning, process; equivalent of the IRP that we went through at the commission.

And the -- I think the story kind of illustrates how we've got -- where we've got to. And the government policy at the time was to phase our reliance on Burrard out, and that was in their 2007 Energy Plan.

It was not as definitive as what you see in the 2010 ***Clean Energy Act***. It was more ambiguous.

And given that, we proposed -- BC Hydro proposed what we thought was a middle-ground approach where we would go from 6,000 to 3,000 gigawatt hours of firm energy reliance.

And we spent a fair amount of time, probably a year, on that proposal with engineering and environmental experts and -- and regulatory analysis.

And we had a fair amount of support. We had some support from our customers. We had one intervener, in particular, that took a contrary view, and did a pure cost analysis and said, well, if you put in 6,000, it's cheaper. And did that with really discounting the government policy, openly discounting it, saying we don't need to consider that.

And it was acknowledged that that reliance, Burrard would rarely run in that circumstance, and that we would end up meeting the load over time with imports.

THE CHAIRMAN: So we've heard from interveners up here that the action of the provincial government in taking Burrard off the

table was what required Site C to be built. We are trading air pollution in the Lower Mainland for a set of environmental consequences up here, plus $8 billion. Would that be an accurate --

MR. CHRIS O'RILEY: I disagree with that characterization. I'll show you how it played out here.

THE CHAIRMAN: Yeah.

MR. CHRIS O'RILEY: So I don't think that's true.

So the BCUC accepted the pure costs view, they didn't factor in what the government said in their energy policy. And they came back with 6,000 gigawatt hours of reliance on Burrard.

And the Province, I think, publicly weren't very happy with that. And they -- they were, I think, offended that their policy had been discounted. And they came back and legislated the reliance on Burrard at zero. And that was zero gigawatt hours, so, here, the firm energy.

And that was initially in a direction and to the commission in 2009. And it was later embedded in the 2010 ***Clean Energy Act***.

The ***Clean Energy Act*** also laid out a path to replace Burrard, and that included replacing the energy with renewable power from the Clean Power

Call, and other calls. It -- where we replaced the capacity with Mica 5 and 6, which is under construction. And it required the Interior to Lower Mainland transmission line, which is under construction.

And our reliance on Burrard for capacity was contingent on -- well, it was only allowed until we got those replacement products done.

So Burrard has been replaced in the system. And was left with a very limited kind of technical role, an emergency back-up role that, in our view, didn't -- didn't justify its ongoing operating cost.

And it also needed -- it's coming up on 50 years old; right? So it needs -- it needs significant reinvestment. So we would be facing a big decision.

So -- so Burrard, in our view, is done. And that was reflected in the decision -- the November 26th decision. And it's been replaced already in the system.

THE CHAIRMAN: I understand the argument. But I would imagine that, just hypothetically speaking, the cost of refurbishing that 50-year-old plant would have been less than building Site C.

And that had Burrard been available for -- pick a number -- 1,000 hours a year, that it would have put off the requirement for Site C for some time. I'm assuming, of course, that the alternative -- the alternatives that have been installed in order to take care of that 6,000 gigawatt hours a year would have been attractive anyway, and would have been part of the stack.

MR. CHRIS O'RILEY: Well, I mean, there's some -- some fairly expensive clean power in that, so ...

And we're dealing with the rate impact of that, so ... I mean, we have it, so it's done. Those contracts are signed.

THE CHAIRMAN: Do you have a round number for what the refurbishment cost of Burrard would have been?

MR. CHRIS O'RILEY: Well, we -- yeah. We did a -- we did a detailed study in 2008. And, you know, years have gone by now, and there's been lots of change in the market. We -- we -- we did not -- and we did not update the study for the purpose of the decision on terminating it.

The -- you know, it's in the -- it's probably in the 4 to $500 million range to kind of make it useful.

The challenge with that -- the challenge with that is whatever energy we put in, firm energy we put in in -- in place of Burrard today, and the stack would -- I mean, the thing isn't going to run. We put all that money into it with the gas and electricity prices and the carbon tax, which significantly changes the effect of the economics of it, it's just going to sit there. And we're going to end up importing. And that was outside the policy.

So the lessen of the experience I went through around the 2008 LTAP, and the back and forth that resulted, is that that policy decision was clearly considered by the government, and they weighed in on it.

You know -- and what I would say, from our perspective, is pouring, you know, money into a plant that -- that isn't going to run. And was also -- you know, the federal is -- is drafting their -- their climate change regulations as they apply to gas-fired plants. So they have previously targeted coal plants. They have not finalized those regulations, but they did signal in the drafting of that that they are particularly targeting plants over 50 years old because they are

less efficient, and -- and, you know, that's not a -- that wasn't determinative of the decision, but it's indicative that -- that Burrard's time has passed.

So we don't see -- I don't see Site C as a replacement for Burrard. I think we've already replaced Burrard.

So let's -- Ms. Melchoir, let's go --

THE CHAIRMAN: I'm just thinking, it's probably time to stop for a bit of a coffee break here.

MR. CHRIS O'RILEY: That's be great.

THE CHAIRMAN: The questions keep occurring. So we'll come back in -- at 10 to the hour. Thanks.

(Brief break)

THE CHAIRMAN: Ladies and gentlemen, can we reconvene, please.

We are on slide 16 now, I think, which makes the interesting point that an order in council has passed to allow the LNG industry to do its squeeze and freeze with its own fuel rather than using electricity.

I must say, when I saw that, an order in council, which purported to change a statute, I was surprised, but, apparently, there is a clause buried deep within the statute that allows that to happen subject only to the GHT criterion, Section 2(m) of the ***Clean Energy Act***.

Now, if the LNG industry is allowed to massively ramp up its use of natural gas for transportation and compression, transportation and liquefaction, what effect does that have on the availability of CH_4 for you guys?

MR. CHRIS O'RILEY: So if -- I think there's an assumption there that may -- that may not be correct, or we might not agree with. And I think the key assumption is that -- well, in our kind of interpretation, there was never a constraint or a requirement on the LNG producers around how they chose their fuel for compression, for the freeze and squeeze.

THE CHAIRMAN: No, I agree. There were some early and area assumptions that they would --

MR. CHRIS O'RILEY: Yeah.

THE CHAIRMAN: -- use electricity for that. And we all knew that that was crazy from --

MR. CHRIS O'RILEY: Yeah.

THE CHAIRMAN: -- the start because they never do and never would and so on and so forth.

So, in that sense, the order in council merely recognized reality.

MR. CHRIS O'RILEY: Yes.

THE CHAIRMAN: But the order in council still interacts with Section 2(m) of the ***Clean Energy Act***, and I thought might have an effect on the availability of -- C -- methane --

MR. CHRIS O'RILEY: Emissions.

THE CHAIRMAN: -- of natural gas for Hydro's purposes. Is there such an effect?

MR. CHRIS O'RILEY: Yeah. And I don't think so. So -- so, yes -- so we all agree that the LNG proponents could decide to use direct-drive gas.

Their -- what we saw the regulation as doing was making BC Hydro competitive so that we could provide them a gas-based solution to running their compression process and perhaps mix in with that some renewable energy, some IPPs, and result in a lower emission scenario than what you might see if they were using gas within their fence to do their compression.

And the only way we could be competitive in that is if you pulled that generation outside this

93 percent.

So I think the government was trying to reconcile the freedom that -- that they'd given, that the LNG producers had around choosing their fuel with, with the constraints that had been placed on BC Hydro around 93 percent.

THE CHAIRMAN: So the intent of the order in council was to violate the inviolable Section 2(m) of the ***Clean Energy Act***.

MR. CHRIS O'RILEY: Well, I think the effect of not making the change would have said, well, they're -- the LNG companies are all going to go in the fence, and there would be no opportunity to mix renewable generation into that -- into electricity supply. So, practically, I think what it did is it opened the door for a lower emissions scenario from -- from the LNG sector.

THE CHAIRMAN: Yeah. I'm still confused about that.

MR. CRAIG GODSOE: Mr. Chairman, if I might. It sounds like a statutory interpretation question.

THE CHAIRMAN: Sorry. Who's --

MR. CRAIG GODSOE: It's Craig Godsoe speaking. BC Hydro's in-house counsel.

It sounds to me like you had asked a legal

question about Section 2.

So Section 2(g) is the greenhouse gas reduction section. I think that's what you were asking about. That isn't sector-specific; in other words, there's no electricity sector-specific allocation from the 33 percent reduction. But I can certainly address this in legal submissions if that's what you'd like.

THE CHAIRMAN: Mr. Wallace.

MR. BRIAN WALLACE: I think it would be useful to hear BC Hydro's position on that in law.

THE CHAIRMAN: Thank you. We'll accept that as an undertaking. Thank you.

UNDERTAKING 92: BC Hydro to provide its position in law with respect to Section 2(g), the greenhouse gas reduction section, with respect to the electricity sector-specific allocation from the 33 percent reduction

MR. CHRIS O'RILEY: Chair, if I could just go back to something I said earlier, and I just want to reiterate. We talked about this estimate for reinvesting in Burrard, and the -- I just want to caution that that's really a kind of a fixer-upper

estimate. It still would be substantially a 50-year-old plant.

And when we've looked in the past at comparable projects for a long-term resource at that site, we've looked at re-powering, and -- which is putting in a new equipment for, you know, different configurations, but that's much, much more expensive. And I'm not going to offer a figure for that.

I think, more importantly, that would trigger a whole raft of environmental approvals, including a federal and provincial process. And, our view, when we looked at this in 2008, is we would not secure -- we would not be successful in citing that, and that was based on in experience for a much smaller plant at Sumas 2 in the Fraser Valley on the U.S. side of the border. And our own experience with the Duke Point project in Nanaimo, which I was quite involved with, that was ultimately not successful.

THE CHAIRMAN: Yes, I take your point on that. But I reiterate the point that many interveners here in the north see that there was a trade-off here, and that they are being traded off. That's enough.

MR. CHRIS O'RILEY: Yes. Okay.

The other point I -- and we're going to come to this, but I fear that it's a bit scattered in the presentation, and so it's this concept of a needle-peak capacity requirement that you're -- you've referred to on a number of occasions. And you've looked at the load duration curve, and you've seen that -- that there is a sharp drop-off in the requirements from the -- the few hours of the year to the -- kind of the bulk, what we call -- there's a shoulder period there, and then there's kind of a flatter period, and then it drops off at the rest.

And I want to make the point that -- we've already got a system to deal with the needle peak. We've got hydro assets that are sized and have -- have generation -- have the right configuration of water and storage and capacity to meet that needle peak. And an example of that would be our Jordon River plant on Vancouver Island, near Victoria. So it's a 170-megawatt plant, that's very little water. And, really, just -- it mostly sits in standby and occasionally runs for two or three hours over the peak.

And so what I'm saying -- and we'll get to it

a little more in this discussion of load curtailment, is -- is we're good on the needle peak. And more resources on the needle peak don't really help. What we need in the long-term is we need more shoulder, and we need more base-load capacity to -- to fill in the bulk. Like, we've got to keep the balance between the needle peak and the shoulders and the -- and the flatter part of the curve in line.

And when you see the chart that was put up earlier around the DSM capacity, we're assuming it shows up in proportion to the existing load, so it comes through at the ideal shape almost by definition. And there's, obviously, some risk around that if what shows up doesn't match the shape, we're going to have a hole.

But I -- I want to reiterate, when you see a need for capacity in a certain year in the, you know, 19 or 20 or 25, whatever that year, it's not a needle peak requirement, it's more for the shoulder. And that's because we've got the needle peak covered with the -- the many hydro assets that are in place in the system.

THE CHAIRMAN: So if you did acquire a gas turbine, you would like to run it 15 or 20 percent

of the time?

MR. CHRIS O'RILEY: Well, you'd tend to run it more often. Yeah. And I think that was why we came up with that figure, I think is 18 percent, in the calculation.

THE CHAIRMAN: Thank you.

MR. CHRIS O'RILEY: So I'm not -- so we're on 17, I think.

So this was our attempt to summarize how the various generating projects come into play here, and the various products.

The generation types and the products that they -- that they contribute to the system, and how they work together with other resources to -- to ultimately allow us to serve the load.

And you asked us, in your questions, the panel asked us a series of -- questions about a series of resources that could be used to firm up additional non-firm hydro to make it -- make it firm to provide capacity. What -- what were the options really to push out the need for -- for new resources? And so we've attempted to summarize that in this table.

And I think the panel offered up -- or asked about the first three resources: the gas resource,

the time-of-use, and the wind. And we've added in the storage hydro, really, for completeness and comparison.

And you can see there's kind of three products or attributes that are associated with different generation types. And it's the question of do they provide dependable capacity? Do they provide firm energy in their own right? And do they interact with other resources, particularly, the non-firm hydro to make that product useable and useful for our system.

And I think we've -- we mainly -- we've talked about that product, the non-firm product; mainly, being our run-of-river IPP hydro because that's kind of -- we've kind of got everything else covered in the -- in the calculations.

So in terms of the table, a combined cycle -- single-cycle gas turbine, an SCGT, would, of course, provide dependable capacity. It would provide its own firm energy, subject to the 93 percent, and the assumptions around how much it ran. And we've said, I think, already, that it would not make non-firm energy useable, like, because it's not able to shift energy.

Time-of-use rates. And, here, we're looking

broadly at residential, commercial, industrial. We've -- we'll come back to the policy restrictions on residential and commercial.

What we're saying here, in terms of dependable capacity, we think that's an uncertain and an unproven resource. And we will talk about that in more detail.

Those time-of-use rates do not provide firm energy. Typically, it's a shift in the -- in the load, not a reduction in the load.

And, of course, they don't help us convert the non-firm energy from the freshet into something that's useful.

Similarly, the wind, it doesn't provide dependable capacity. It does, of course, provide energy. And we calculate that based on its average annual production. And it does not, again, help with making the non-firm useable.

And, finally, the storage that hydro provides dependable capacity. It generally provides firm energy. And it is the one thing that will help us shift some of this freshet non-firm energy and make it more valuable for the system.

MR. MATTISON: Mr. O'Riley, you lost me. And you lost me on the gas. And so you need to do

it again for me. And I apologize if I'm stupid.

MR. CHRIS O'RILEY: Okay.

MR. MATTISON: But if the answer in the first two columns is, yes, I can't see how the answer in the third column or the fourth column, I guess it is, is a no.

MR. CHRIS O'RILEY: Yeah. And, really, that goes back to the hand-out, and I -- I don't know. It's this handout, Ms. Melchoir, the ...

And that -- the -- so this is the profile of generally run-of-river energy, and the non-firm portion, the 15 percent of that energy we would consider as non-firm, it's typically in that big bump in the spring.

And our challenge with making that energy useful is we have to find a way to move it to other parts of the year, whether it's the -- typically, the winter where we have higher loads. So that it's a -- that non-firm energy is a poor match for our load.

And -- and a single-cycle gas plant will help you meet your load in the winter, and you can turn it on, but it's completely independent of that freshet energy in the spring.

MR. MATTISON: I agree.

MR. CHRIS O'RILEY: You can't -- you can't store -- you can't use it to store that energy and move it.

So what you end up doing is you end up selling it and spilling it sometimes, and then -- and then running your gas plant. So that's the ...

MR. MATTISON: Well, I guess -- I mean, if you have the capacity and the energy sitting there, not operating, and when you need it, you fire it up. Then with this -- I mean, it sits there, it's firm and it's available. And it's just not used when you have this, so this isn't wasted. Are we -- is it just semantics?

I mean, okay, it's -- this is never going to be firm. I get that. But you're using this energy with the gas to have a firm resource waiting for you.

MR. CHRIS O'RILEY: Well, the effect is you end up with a firm resource. And what I'm saying -- what I'm saying is that the firm resource is coming from the gas plant itself, whether you have this firm -- non-firm energy or not is kind of -- is really immaterial in it; you end up with a firm resource from the gas plant.

And another way of saying it is there's not a

synergy between this freshet non-firm energy and a single-cycle gas plant.

MR. MATTISON: No, I understand that. Okay. That's fine.

THE CHAIRMAN: I would be more comforted if that diagram were not run-of-river stuff, but was wind where, particularly, if you have an ever larger fleet of windmills out there in different parts of the province some of the unpredictability begins to disappear, and you guys have a wonderful capacity to calculate that. You may still be able, in dips in wind availability, use gas turbines to fill in the blanks. So I fully understand the argument about storage and the freshet, but I don't think that diagram tells the whole story.

MR. RANDY REIMANN: So I think, yes, certainly wind integrates well with the system. And it does use up flexibility of the system as it goes up and down. And wind tends to have an attractive profile where it's a little lower in the spring/summer, and higher in the winter.

So from that perspective, wind is quite a nice resource, but we don't actually have a non-firm energy component from wind. We don't see the same amount of inter-year variability on wind,

so, in fact, we count on wind for its expected output; we don't de-rate it.

So when we talk about the non-firm energy, it's really specific to the run-of-river plants, and the -- most of that energy comes in the freshet, and that's when it's very difficult to use.

MR. CHRIS O'RILEY: Just in terms of some -- I gave you before the statistic for run-of-river hydro, so the contract firm amount was 72 percent of the average. And through our system integration, we got that up to 85 percent.

For wind, the contract firm amount is 94. And we count on it in the system at 100 percent, so we give the full credit of the diversity of the wind resource; we count that in the -- in the -- in the load resource balance.

THE CHAIRMAN: Okay. Back to the slide a bit.

Time-of-use rates for industrial uses, I'd be surprised if you couldn't get a little energy consumption reduction out of time-of-use pricing.

MR. CHRIS O'RILEY: Yeah. Well, we're going to talk about that in more particular --

THE CHAIRMAN: All right.

MR. CHRIS O'RILEY: I think -- to answer your question, I think it would be almost immaterial because the feedback we've had from them, through these activities in the past, is they want to make the production of.

THE CHAIRMAN: So this is strictly peak-shaving stuff?

MR. CHRIS O'RILEY: It's -- yeah.

THE CHAIRMAN: Okay.

MR. CHRIS O'RILEY: And we're going to talk about that.

THE CHAIRMAN: Yes.

MR. CHRIS O'RILEY: Okay. So let's go.

Okay. So we're on to question 3, which is -- considering, really, capacity-focused products in the load resource balance. And right now I think we're going to start with on the load-side or demand-side products, and what -- what that does. And what are the opportunities to defer resources.

So when we look at these types of resources, the first thing we do is try and figure out the degree to which we can rely on them. And, again, talked a lot about our obligation to serve and our legal obligation to serve, and that really drives the need to be prudent around this.

And we look at that on a case-by-case basis, looking at the individual resource. And then we look at it in context of our larger reliance on these types of programs. And we've got a heavy reliance, as we'll see, on demand-side management for capacity.

We've also got a heavy reliance on capacity from intermittent resources that both of which, I would say, are non-traditional resources for a utility, and we are making a very big reliance on them.

So if we go to the next slide, we are -- we are heavily reliant on load-side resources for capacity, and -- and for intermittent. And the 1,400 megawatts is -- it's a big number for us. I mean, it's -- it's three units at Mica. And when we get Mica finished with -- it will be 2,800 megawatts, it will be half of Mica. So that's a very significant reliance in our -- our base, in our plan, going -- going out. And it represents 85 percent of the incremental capacity needs in the -- in the system over this period.

And if there were a number in our IRP, our long-term plan that we're most concerned about, it's that number.

And I think we've been appropriately aggressive in coming up with it. But what I would highlight is we've got -- we've got our contingency plans in place, we're working today on the early stage work for Revelstoke 6, to keep that project as an option because of -- if this doesn't show up -- or it's not showing up in the profile that we're assuming, which is a very generous profile, perfectly matching our load, we're going to need to move on Revelstoke 6. So I think that just highlights our concern.

And I -- and, again, just reiterate that capacity is kind of the most critical thing when it comes to running a utility, and especially a winter-peaking utility.

And when we get into scrapes here, often, you know, we'll have problems on our generation system. We'll have a high load. The inter-time might be de-rated and bondable is experiencing the same type of situation with a -- you know, an arctic express, as they call it. Right? You -- we get -- we get cold; they get cold, then -- and the loads are really high.

So we are concerned about an undue reliance on capacity, and that is why we're concerned about

these two resources, both of them, again. As I call them, they are non-traditional for -- for capacity.

THE CHAIRMAN: I understand how that would be the biggest worry that you've got because BC Hydro is relatively inexperienced with this, you know, compared to, for example, some of the U.S. utilities that have been ploughing this furrow for a long time. And have more empirical experience on ordinary price elasticity never mind demand management tactics that require expenditures or foregone revenues by the utility.

It's an area where I would expect that your experience will get a lot better in the next few year as the effects of current price increases --

MR. CHRIS O'RILEY: Yeah.

THE CHAIRMAN: -- and foreseen price increases begin to feed in.

MR. CHRIS O'RILEY: Yeah. And I'll ask the panel if anybody wants to jump in on that.

I -- you know, I think when you look around at the winter-peaking utilities, this is a -- I think a lot of the examples in the U.S. where they've done -- had more reliance on these type of resources have been more summer-peaking utilities.

And where they have the air-conditioning load. And that's just a little different than -- than what we see in the north. You know, and you can turn your water heater off in the summer peak and probably better off to do that. Right? And there's been a lot of experience on those type of things.

So this is new ground for us, and we -- and I guess what I'm trying to say is we are making a big commitment to capacity -- load-side capacity in our plan already. And I think -- it's the 85 percent is -- is a -- is an example --

THE CHAIRMAN: Well, we'll come back to the DSM business, I'm sure, later in this suite of questions --

MR. CHRIS O'RILEY: Yeah.

THE CHAIRMAN: -- but there are elements of option 3, or even option 4, that, I think, would bear thinking about against the environmental consequences of Site C, for example.

MR. CHRIS O'RILEY: So let's shift -- yeah, let's shift to slide 20.

So -- and this is getting at one of these products, which is the time-of-use. And I've heard it said in the - or seen it in the transcripts for the proceeding that there's some ambiguity about

whether there's a policy constraint on time-of-use for residential and commercial customers. And I just want to say that the Province has been crystal clear with us on that, so there's no ambiguity at BC Hydro about whether this is allowed. And our view is it's not. And we're not working on it. Like, there's no --

THE CHAIRMAN: We understand that.

MR. CHRIS O'RILEY: Okay.

THE CHAIRMAN: I also understand that you've had industrial time-of-use protocol for a long time. And that the Minister's announcement that it was allowed was possibly a little after the fact.

MR. CHRIS O'RILEY: Yeah. Yeah. So I -- we -- we've had it in place for 2006. And they are looking at it again through this --

THE CHAIRMAN: But just to sort of short-circuit this, I read your report to the BC Utilities Commission on why there's been no take-up in RS 1825. And I think your report goes a long way to answering the question.

Now, it's pretty darn complicated, and the advantages to an industrial user are not immediately apparent, even for a treasurer with a sharp pencil. And that possibly some

simplification of that offered contract might be useful.

MR. CHRIS O'RILEY: Well, I think we would agree with that, so ...

The -- so I think if we turn to the load curtailment. And maybe just a point here is for industrial customers, the concepts --

You want to go to the next slide. Sorry. Yeah. Slide 21. Yes. So we're on 21.

We see the load curtailment and the industrial time-of-use as two ways of getting at the same process flexibility among our industrial customers. So I just want to make the starting point that these are not additive. And there are two different ways of getting at the same thing.

And we have highlighted these in our IRP, recommended actions, that we want to pursue these programs in the long-term. And it's important to do that because we have a long-term need for capacity.

You know, we have -- we have one large hydro site to develop at Site C. We've got a few opportunities in our system for expansions. The load will continue to grow, and we're going to need capacity resources. So we think this is a

long-term need, and that we have to do that.

THE CHAIRMAN: All that's true, but you've been in this time-of-use pricing business since 2006, and I'm surprised that you haven't gone beyond a desktop study.

MR. CHRIS O'RILEY: Well, to some degree, we -- we have. And we'll -- we'll talk about that.

But -- well, I guess I would say we're not on the capacity side; we're not sitting idle again, going back to the 1,400 megawatts. Like, I -- we feel we've been -- we've been busy on the demand side. And -- and running full out since 2006. So -- I won't repeat myself, though.

The -- I'll just -- I'll just give a little bit of my personal experience on this. When I worked at Powerex, I was part of a team that put in place a -- we -- we called it a pilot. It was a price-dispatchable curtailment program in the late '90s, and it gave customers the -- the opportunity to curtail in -- in response to high market prices, and we shared the savings. And we got -- I think in the end, we got about ten customers signed up, and we had a few curtailments, and were able to share some benefits with customers.

Later on, in 2007 and 2008, we introduced a

more formal load curtailment program in the company that required customers to sign up for two or three years and commit. It wouldn't be voluntary, it would be commit, that when we called, they would curtail. And we gave them a reservation charge for that.

And so a few learnings of that -- that I took away -- I mean, there -- it's -- it's a relatively limited subset of our customers that have this process flexibility to respond. And -- and you -- you need -- you need the ability to turn down parts of your process. You need storage to -- to -- you know, inventory materials so that you can keep other parts of your process working. You need a -- you know, the controls in place, and the -- the infrastructure for that.

And that translates into a limited number. And, predominantly, it was the thermal mechanical pulp customers, and the pulp chlorate companies that were most keen on it.

There also were a fairly limited number of megawatts and a limited number of hours that they were willing to curtail before it started to seriously affect their business.

The other conclusion I took away from it --

and it ties to the hours -- is it's very much a needle peak product. So back to my earlier discussion about what we need, we only need so much needle peak, and we've got it in our system. So it didn't help with the broader -- the broader need for capacity in the shoulders and -- and the flatter part of the curve.

So -- and I would also note that our best customer for this, the customer that was most keen and contributed the most megawatts, was the catalyst mill at Campbell River. And, unfortunately, they are no longer with us, so -- so that -- that takes away of -- I mean, they were perfectly set up, you know, given the characteristics to respond.

So we've had some experience with the short-term programs, like I said. And I -- I think that experience has given us some kind of -- kind of given us some concern about the long-term viability.

We absolutely will work to try and prove out the long-term viability of this, but we need to do that in a measured and a prudent way.

And I think, again, given the context of our reliance on capacity in this current time period,

this is not the time to double-down on capacity DSM.

The other program, capacity focused DSM, this would be more broadly focused on residential and commercial customers. So this would be our first attempt to identify, demand, and load control. So this is the -- kind of the -- this would be the Canadian equivalent or the cold climate equivalent of turning down the water heaters over the -- over the peak.

And -- and this work is -- is very much at the early stages. And the extent to which our customers are going to be willing to accept and -- and implement the behaviour is -- is really unproven at this point.

So we're not in a position to -- to increase that amount, you know, until we get some -- until we make that more solid. But, again, it's something we need to do; it's something we've committed to do in the -- in the IRP.

The next slide.

So having said all that -- I mean, you asked us to prepare a portfolio that shows the effects in delaying our peak capacity requirements by putting these resources in. So we've put in an amount for

industrial load curtailment and capacity-focused DSM. And we've shown some scenarios of -- of -- without LNG and different scenarios with LNG and we've shown where the energy comes in and the capacity requirements.

The first point I -- I want to make is this is a relatively crude calculation. And it's really crediting the needle peak capacity that we think we can get from the industrial load curtailment kind of -- we're just assuming that meets our needs here.

And -- and I think, as I've said, it's a much more complicated calculation. So I think a one-for-one deferral from -- of -- you know, our capacity need from -- from 1919 -- 2019 to 2025 is -- is aggressive, but that's the way the calculations were done.

You know, again, back to the -- the context for this being the amount of DSM that's already in the stack, and you're asking the person who is responsible for -- for keeping the lights on in the Province; I'm not recommending that we do this.

And -- and, in fact, what -- we would come at this with supply-side resources, which is kind of addressed on the next slide.

Ms. Melchoir, yes.

So you asked us about supply-side resources, and these are more viable resources.

And Revelstoke 6, we -- we know exactly what -- how that would perform, and how we would -- would implement that.

GMS, 1 to 5, capacity upgrades, we've done a similar project on units 6 to 8 at -- at GMS already.

The 1 to 5 project is -- is cheaper than -- than Revelstoke 6. It does come with a lot of hair on it. It's quite disruptive for the plant. And you end up -- in order to do the upgrades, you end up taking units out for the winter. So you get a short-term hit for a long-term gain. So the very time we would be needing the capacity, we're actually ending up with less.

So it's -- I think that just goes to illustrate the complexity of this, and how the various components interact.

It does show, when you put those resources in, that you shift out the need for capacity. And that's certainly a viable portfolio.

It's -- it's -- you know, as the person running the system, I'm much more comfortable with

supply-side resources than the ones we talked about on the -- on the previous slide.

The challenge for this, with this portfolio, is we do have an energy need. And depending on the assumptions for LNG, you end up -- you know, that's -- that's uncertain. And our concern with this portfolio is it's a backdoor way into the more expensive clean generation portfolio because the -- you end up -- you end up with this capacity, you end up doing a call, and you've -- you've -- we're backing our way into a -- what is a higher cost portfolio.

THE CHAIRMAN: Just to -- sorry, you're going to go on to the next slide: characteristics of ...

MR. CHRIS O'RILEY: Well, do -- yeah. And what -- what -- what I'm trying to say here is there's a number of constraints imposed on the company. And we've talked about the policy constraints.

What I would say is those are -- well, we've talked about that they clearly are articulated, and I think have been -- have been -- become more clear over time.

What I would also say is they are very much

aligned to what a prudent utility would do in terms of making sure you have enough supply to meet demand. And -- and they are particularly well-aligned to a utility that's in a part of the world where we are concerned about climate change and -- and greenhouse gas.

So what -- what we're -- what I want to say about this is it is -- whenever we've faced a large investment decision, there is always the temptation and -- and probably a responsibility to push on the planning criteria, and see if there's ways to avoid or defer the investment. And -- and -- we -- we think that is an appropriate thing to do when you're considering a short-term problem. Or you've got a bridging situation for a number of years, and we've done that in the -- in the past.

But I want to reiterate here, we're not dealing with a short-term bridging need. We're dealing with a long-term need for energy and capacity.

And we don't believe --

THE CHAIRMAN: Just to refresh us, that Rev 6, Shrum, and clean intermittent IPPs for energy, what was that in terms of either UECs or present value? And how did that compare with

Site C?

MR. MIKE SAVIDANT: My recollection is 154, subject to check, on UEC. One, five, four.

THE CHAIRMAN: One, five, four?

MR. MIKE SAVIDANT: Yeah, the portfolio and PV, which is generally our measure of cost-effectiveness with --

Sorry, Nancy.

Our portfolio and PV differentials, which is our measure of cost-effectiveness that considers timing and everything like that, I believe the PV differential, at our 5 percent discount rate, was, roughly, $630 million.

THE CHAIRMAN: Okay. That's for the -- that's for a Site C sized portfolio, these --

MR. MIKE SAVIDANT: The UEC is when we do the matching block-to-block. That's mostly used -- the block analysis is mostly used for an environmental attribute analysis, but we do provide UECs to kind of look at the long-term cost.

THE CHAIRMAN: Yeah.

MR. MIKE SAVIDANT: The portfolio PV differentials are not perfect matching --

THE CHAIRMAN: No.

MR. MIKE SAVIDANT: -- they say what is the

load --

THE CHAIRMAN: Yeah.

MR. MIKE SAVIDANT: -- how is it growing? How are you going to bring on resources.

THE CHAIRMAN: Yes. And we're going to come back to the timing issue.

Okay. Thank you.

MR. CHRIS O'RILEY: And so -- and just to -- so reiterate, the problem with relaxing the planning criteria is you put yourself -- you can put yourself in a situation where you don't have enough.

So that goes back to the -- our fundamental responsibility as utility operators, my responsibility. And we don't think that's a prudent thing to do.

So what -- what that -- that -- the implication of that is when we're considering alternatives, we should consider alternatives that meet the planning criteria.

And, as Mr. Savidant just highlighted, that is the clean generation portfolio that -- that -- and the clean generation portfolio with the thermal, and those are the -- the most likely paths we would take in the event this project wasn't

proceeding.

THE CHAIRMAN: Okay. So --

MR. CHRIS O'RILEY: And both of them are -- are higher -- higher costs.

THE CHAIRMAN: Yeah. But just to summarize that a little bit there.

If you fed that Rev 6 portfolio in, as required, over time, you'd wind up with adding, give or take, 10 percent to the energy capacity of the utility at 154 over an existing -- what's your average of EC now?

MR. CHRIS O'RILEY: Oh, our average is -- it's, like, 40.

THE CHAIRMAN: 40?

MR. CHRIS O'RILEY: Yeah.

THE CHAIRMAN: Okay. So you get 90 percent of 40 and 10 percent of the 150, and you would wind up with a price increase that would be felt by all British Columbians, or all ratepayers.

Another way of looking at it is that you would be charging those folks $630 million to avoid the environmental consequences of Site C. Is that another way of putting it? For awhile anyway.

MR. MIKE SAVIDANT: So the $630 is -- is an NPV analysis. That's the average price of that.

THE CHAIRMAN: Yeah.

MR. MIKE SAVIDANT: What we would be looking at is higher rates for the duration of the project.

You know, the NPV is a short-term analysis. It's conducted over -- in the portfolio, this is conducted over, approximately, 20 years of the project's operating life.

THE CHAIRMAN: Yeah. I understand that. But what I'm getting at is that there's a quantifiable trade-off here.

MR. MIKE SAVIDANT: Yeah. When we looked at this, we looked at -- I mean, we've talked about the portfolio analysis before, there's a financial benefit of proceeding with this project; I believe -- we believe that.

When we look at the environmental impacts, and all projects have impacts, and so what you're looking at -- and we did -- to -- to address this, we used the environmental attributes that -- that I know you've -- we've talked about previously.

So what you're looking at with this project is you're looking at the impacts that we've described in the Environmental Impact Statement -- and I'm not going to revisit it again -- versus Revelstoke 6 and GMS, plus IPPs for energy in the

long-term. And so you're looking at this impact versus not -- no impact, but a spider web of impacts at various sites across the Province.

We believe we've quantified the difference in footprint in terms of what those would be. But when we look at footprint, this project would have a larger terrestrial print, and we believe that is likely.

We believe the project would result in however lower GHGs, not -- not a large difference compared to the clean generation portfolio, but when we're looking at municipal solid waste, that's a component. And local air emissions and things like that.

We're also required to look at the impact on economic attributes outside of just the ratepayers, but in terms of jobs and GDP.

We also believe this project has a higher impact on jobs and GDP. So when we looked at this project, we know, no matter what we do, there's an impact to it.

But we believe on balance that when you look at the financial benefits, the economic benefits, and a little bit of a mix on the environmental attributes, we believe this is the preferred

project.

THE CHAIRMAN: I understand there's no free lunch, but the numbers, even as a crude indication, are interesting.

On the environmental side-effects of that portfolio, for example, we don't know what, at least in detail, the other clean intermittent IPPs might be. I would expect that Rev 6 and the Shrum improvements would have close to zero in an environmental effect, as you could imagine.

I think you undersell your contribution to greenhouse gas emission, at least in the EIS. You may recall, I had to ask a question to get that 43 to 76 million tonnes avoided and so on and so forth.

So I think -- I think the environmental argument may not be particularly strong in favour of Site C against that. But, nonetheless, we have a -- we have a thumbnail way of comparing these portfolios.

If you did that, would you argue that you would simply be putting off Site C for a decade?

MS. SUSAN YURKOVICH: Mr. Chair, if you did this, it does not change overall the trajectory of the increase in need for electricity.

And we recognize that this is a big, lumpy project, and it comes in at one time resulting in a short-term surplus. But over the life of this project, 70 to 100 years plus and beyond, if well-maintained, we believe that this is the right thing to do.

And we recognize that these are big decisions. And they have impacts and they take courage and they invite very significant conversations. They have in the past when we brought them in, and they have today. And I mentioned that in my opening.

I just would reflect that over the long term, these assets have been a benefit to the Province by way of clean, reliable electricity. And those jurisdictions who do have the ability, the geography to undertake projects of this kind are doing so across the Country.

THE CHAIRMAN: Yes, I understand that. And we are -- we will come back to some of the details of this in the next 19 questions, I think.

I would even argue that from a financial point of view, Site C undersells itself against IPPs because, after all, after every 20 or 30 years, you get to buy them again. It depends a

bit on what your social discount rate is. But if it's low, as most of the literature would guide you to, there is an unquantified advantage to publicly-owned, long-term electric resources.

Okay.

MR. CHRIS O'RILEY: Yes. So we're concluding here, and it's really on that point, and -- you know, I've -- I've had the fortune of spending my career around -- career so far around hydro plants, so coming up on 25 years. And there's really kind of three things that are unusual about large hydro plants. And one is the fact that you do incur all the costs up front, so you -- you -- in some ways, you pay this financial penalty. And it's always -- there's always sticker-shock with them. And there has -- there's -- that goes back to the -- through the history of the company.

The second thing that's unusual is they do produce a steady stream of output that doesn't decline, and it lasts for generations. There's -- there's nothing in our society that lasts like hydro plants.

And I'm currently replacing the 85-year-old -- or rebuilding the 85-year-old Ruskin plant, and it was built in 1929. And there's nothing. We

look out there and -- and say -- well, we're still relying on it. The bearings in it were made of wood, you know, to ...

And the third thing is that the feasibility of hydro plants, especially large hydro is very much site-dependent, so there are only a -- there are only a select few, relatively few, opportunities to do this.

And, really, in our -- in our economy and our society, there's very few comparisons to this kind of investment. And you might say, well, maybe a major highway like the Coquihalla, which has all these spin-off economic benefits in turn for an upfront investment, as an analogy, to it. I think the point is that it's very unusual and rare to find that type of asset.

And I -- I think the point, Mr. Chairman, that you touched on is the financial analysis is quite conservative when you look at this type of asset. And it's really the present value, you know, which we've come to settle on in these proceedings as the way to do it. And the key part of that is you discount away so much of the value.

In other portfolios, the clean generation and the thermal portfolios, the costs continue to rise

over time. And in this portfolio, with this project, the costs decline over time.

And when you look at this portfolio 25 years out, the benefits are discounted to about 10 cents on the dollar.

And what we know, from experience, when you get there is those benefits will be 100 cents on the dollar. And that's the magic of a large hydro plant. And it's a way that we can pay for the benefits to a future generation.

THE CHAIRMAN: No, there's no question that the view one takes of these things is highly time-dependent. 50 years ago the top of the pops for hydro was the Moran Dam on the Fraser, plus Hat Creek coal.

MR. CHRIS O'RILEY: Yeah. Yeah.

THE CHAIRMAN: That's unthinkable these days. Anyway ...

MR. CHRIS O'RILEY: Yeah. Well -- and, really, the alternative to the Peace projects was, in fact, Hat Creek coal. And BC electric were advocating for a -- and it was cheaper. So imagine, you know, if we had done that.

So I just want to just remind ourselves I'm not saying we should ignore the present value

analysis, you know, I'm not sure what I would replace it with, but we -- we have to recognize that there's a -- a tremendous societal value that's -- that's very broadly felt in -- in our Province that -- that we want to consider. And it's the back-end, really, three-quarters of the value of the project that disappears when you do the --

THE CHAIRMAN: Wonderful article by Kenneth Arrow *et al* in science on social discount rates, which is, I commend to you. Anyway ...

Madam Beaudet.

MS. BEAUDET: Thank you, Mr. Chair.

I would like to know what is the history of outages in British Columbia. How frequent? How long they last? Do they happen in winter more than summer? Et cetera. And the reason why is I know, for instance, in Quebec when we had the ice storm, we didn't know outages, and the policy of the government was that, you know, it was a crisis. Like you mentioned earlier, for BC Hydro, there was a crisis. And that it should never happen again.

And I think very often you look at investing in something that you can totally rely on like Site C because the IPPs would be an added value,

but there isn't as much control as something you own. And -- or satisfaction. I mean, the IPPs, you don't have the control on the quality of service all the time.

So I would like to see to what extent the -- the public is creating something like that in the sense that your first requirement by law, I think, is to make sure that everybody has electricity all the time.

And I live in a province now that most people have a power -- a source of power independent from the main service because we are having outages all the time.

So maybe we have to frame our minds, you know, in -- with the restriction that we impose on ourselves in terms of environmental impacts.

I mean, if -- we are very demanding on -- on the top-notch quality of service. It has also -- we have to look at the environmental impact that this brings.

And I would like to have a picture of what happens here in BC -- I mean, how often do you get outages and how long are they and what season they happen?

MS. SUSAN YURKOVICH: Thanks, Madam Beaudet.

I'll address just a couple of your first points, and then ask Mr. O'Riley to address the outages.

I think your question referenced is it more important that we control the generation. I think we have about 20 moving up to about 25 percent that is delivered in contracts through the independent power sector, and we are comfortable in that. It's not a question of ownership for us as BC Hydro.

Your question, though, about I guess the public's desire to have power in the hands of the public, I think is an interesting one.

We have that, as I mentioned, in legislation. Yes, the heritage assets are held by the public in perpetuity. And I would say that in previous times, this has been tested maybe through trial balloons of public policy.

I think -- while I don't have statistical information to verify that -- I think there was a strong sense from the public that it was desirable to hold these strategic assets in public hands.

With respect to our outages, we live in a province that has some spectacular terrain, as Ms. Davis, in our tourism -- the folks from Tourism BC were noting. We have some very challenging

landscapes, and we do experience outages. And I would ask Mr. O'Riley just to speak a few minutes to that.

MR. CHRIS O'RILEY: Sure. And, I mean, I distinguished Madam Beaudet earlier between outages on the distribution system and, really, the -- the transmission system. And we do have our share of those. And we have a lot of trees in the Province. And there's a direct connection between our willingness and ability to cut trees down or cut back trees and our outages on the distribution system.

And, you know, we're probably a little bit behind where we should be on that, but I think we're kind of in the zone of acceptability on that calculation, and we look at it every year.

I think the kind of outage that you were talking about, the -- the major disaster in Quebec and eastern Ontario, we've not experienced that. And I -- and I think to some degree, that's fortune. And to some degree, it's how we've -- we've set up our -- our system.

And the mix of generation and regional diversity and access that we have to the U.S. and such. And -- and -- but we've not experienced it.

And we -- we do take that experience as a -- as a bit of a cautionary tale, and it's something -- you know, there have been big system outages in the western North America in the last 20 years. In 1996, and in the 2000s. And every time they happen, there's a, you know, a big investigation and -- and calls for -- for let's do better. We must do better. And, you know, it can't happen again.

And so I -- I think we've -- we -- we have -- if not here directly, we've -- we've tested society's openness to taking more risk on the -- on the electric system. And I would say that that openness or willingness is declining.

What we are seeing I think with the transition and work and increasing reliance on -- on technology for work, that the cost of outages, even -- even a, you know, distribution outage is -- is going up. And we had a -- we had an architect on our board a number of years ago, and he had a -- his office downtown was impacted by a major distribution outage we had in Vancouver a few years ago, but -- due to a fire. And he was very articulate in describing the cost to his business and the disruption of taking all those knowledge

workers out of the -- of the economy for three days. It was very, very -- very, very troubling for him. And he was, in fact, considering, what you suggested, which is putting in their own back-up diesel generation as -- as some of our customers have done. And we've -- we have anecdotal views on that.

But, again, I think it goes back to the planning criteria, and I think it's back to having enough. I think if we're having outages in this Province because we don't have enough generation, that -- that is a crisis and it's a -- it's a --

THE CHAIRMAN: That's a different sort of crisis?

MR. CHRIS O'RILEY: Yeah, it's a different sort of crisis. And -- and it -- and I believe it's at the root of the -- the planning criteria that we have in place today.

And, again, I would say, as the person who is, you know, implementing that, I think it's -- I think we're in the right spot.

THE CHAIRMAN: Okay.

MS. BEAUDET: There is an environmental cost to that, and a financial cost as well?

MR. CHRIS O'RILEY: Yes.

MS. BEAUDET: Thank you.

THE CHAIRMAN: I think we have come to the end of the initial 6 questions and have only 19 left to go. One little piece I would like you to give us, given the 93 percent threshold, the famous 93 percent threshold, how many gigawatt hours does that allow you year-by-year off in the forecast period? Do you know offhand? Or I would be glad to have a brief table at your convenience.

MR. RANDY REIMANN: I think we could probably locate it in the filing.

THE CHAIRMAN: It's probably already there.

MR. RANDY REIMANN: Yeah, it's in chapter 5. It works out to about 700 megawatts of SCGT capacity, but I don't recall the gigawatt number, but we could probably -- oh, hang on. We could get --

THE CHAIRMAN: Chapter 5 of the EIS has it?

MR. MIKE SAVIDANT: I've got it right here. Table 5.33 of Section 5 of the EIS, page 5-54. We looked at it a few ways. We looked at it -- there's a space available for natural-gas fired generation in fiscal 2022 --

Sorry, Nancy.

We looked at the space available for natural gas-fired generation in fiscal 2022. That's,

approximately, 4,356 gigawatt hours.

When we looked at that in terms of how many megawatts of simple cycle gas turbines we could bring on, it's, roughly, 530 megawatts in fiscal 2022 that we have room for.

THE CHAIRMAN: Yeah, that's great. I just forgot that.

MR. MIKE SAVIDANT: It's a big document.

THE CHAIRMAN: You know, I had it memorized last fall.

Let's see if we can get in at least Question 1 of the 19 before we break for lunch.

Questions 1 through 19 addressed:

MR. MIKE SAVIDANT: Water rentals, I can answer.

So water rentals are calculated based on a schedule that we received from the -- I believe it's the water stewardship division of the Ministry of Environment. There's different rates for different sectors.

For hydro power, there's really three categories of rates. There's one rate for capacity, one rate for -- so the installed capacity. One rate for the generated energy, and there's a very minor rate for the amount of

storage.

Of those three, the biggest cost in terms of water rentals, is the energy one, the one per gigawatt hour of energy we produce.

So the way those work for hydro power, especially for the energy specifically is they are tiered-water rental rates. We talked a bit about that before.

So for the first 160 gigawatt hours of generation for a company, you pay a lower rate. It's a dollar and change -- I can't remember the exact rate -- this year.

For the second tier of water rental rates, it's, roughly, $6 and change, and that goes from 160 gigawatt hours to 3,000 gigawatt hours.

And then above that, 3,000 gigawatt hours and above, up until the change in 2018, we pay $7.20-something cents. That's evaluated by company.

So, effectively, with BC Hydro -- this is why we say Tier 3 only applies to BC Hydro. BC Hydro, an IPP, if they generated 5,000 gigawatt hours, would have Tier 3 up until -- up until 2018, none of them do, it's really a hydro rate with Tier 3.

THE CHAIRMAN: Does anybody else pay that

much? Does Fortis pay that much? Do they get into Tier 3?

MR. MIKE SAVIDANT: No. For the fiscal --

SPEAKER: No.

THE CHAIRMAN: No? So this is what you call categorilla, huh?

MR. MIKE SAVIDANT: It's just for us.

So what the change in 2018 will do is it will eliminate the third tier. So for every gigawatt hour above 160 gigawatt hours for the company, we're well above that, of course, you pay the lower-tiered water rental rates, it's about 1.25 less. If you look at this project, it lowers our UEC by about 1.25.

If you were to align our rates with IPPs, either just flatten it out at Tier 2 or flatten it out at Tier 1, you're looking at about $5 differential in -- in dollars per megawatt hour.

THE CHAIRMAN: $5, if you levelled it out at a level 2, say?

MR. MIKE SAVIDANT: Yes.

I'm not sure how we would compare to consumptive use. This project isn't a consumptive use, it passes water through the turbines. So I don't really have a good metric for comparing to

gas fracking or pulp and paper.

THE CHAIRMAN: Well, I'm -- my observation is that ratepayers are getting hosed on water rentals when consumptive uses of water, not, you know, through the turbines, that pay very little. And I'm just curious if you have any statistics on fracking or pulp and paper? Or what people pay for irrigation?

MR. CHRIS O'RILEY: Well, we actually weren't able to get that, Mr. Chair. I agree with you. I think it's a fraction of what we pay for water rentals.

THE CHAIRMAN: Okay.

MR. CHRIS O'RILEY: There's certainly a -- been -- they are discussing changes to the ***Water Act***, and -- and I think that question of what should consumptive users pay is a -- kind of a very live issue in the -- in the Province right now, but -- but I would go out on a limb and say it's a fraction of what we pay for the -- the water.

THE CHAIRMAN: Okay. But the -- this is a --

MR. CHRIS O'RILEY: I might defer to the panel --

THE CHAIRMAN: -- bit of a set-up of a question because, as you may know, the panel has

some internal expertise on the questions, but I did want to get this on the public record.

The key is that last sentence:

"If Hydro were charged the same as the IPP, what would be the difference?"

And you're saying that it's on the order of $5 a megawatt hour, and that is material.

MR. MIKE SAVIDANT: Yes. The -- I've pulled it together when I saw this this morning, the rental rates in 2013 for Tier 2 are $6.01.

The Tier 1, so that's for everything under 160 gigawatt hours per year, is, roughly, a buck thirty. $1.30.

THE CHAIRMAN: Okay. Let me suggest that we break for lunch, but that we not wait until 1:30 to come back; we'll come back at 1 o'clock. All right? Thanks very much.

(Proceedings adjourned at 12:00 p.m.)

(Luncheon adjournment)

(Proceedings reconvened at 1:00 p.m.)

THE CHAIRMAN: Good afternoon, and welcome back.

Could we have Question 2 up on the slide, please.

Question 2:

"The historical accuracy of EIA forecasts? A trend of rising inaccuracy from 1985 to 2008."

I just asked Mr. Ince when he took over, and he said 2007, so this will be interesting.

Could you put that graph up.

That's the famous graph.

Over to you.

MR. DAVID INCE: Thank you, Mr. Chair.

And I should add, I came into the load-forecasting function midway through 2007. So, as I said, I was right at the edge of the cliff, and I was widely criticized for reducing the 2008 forecast as being overly conservative, and by the end of 2008, I was being criticized for forecasting too high, so ...

THE CHAIRMAN: Like Mr. O'Riley, your timing is pretty good, huh?

MR. DAVID INCE: It was right at the cusp.

But this is an interesting chart in that it's from the energy information administration, so they're from the -- they're from the U.S. Department of Energy. They'd be doing long-term forecast and comparing their accuracy versus the actual outcomes. So what happened this the forecast versus the actuals.

We have -- so the history I'm familiar with is in the mid-2000s, our forecast was being criticized overly conservative.

So during the boom of, let's say, 2003 to 2007, we were underforecasting. And then subsequent to the great recession, which I've talked about in December, we were criticized for overforecasting.

The 2007 forecast I know was widely criticized because, again, it was right at the edge of the cliff. And that was a profound disruption.

So we are still recovering from that event. And I would suggest that economic growth rates that we're assuming right now are a lot less than they were pre-recession, as -- as are the load forecast.

So pre-recession, our load forecast, would be growing at around 3 percent per year, and now --

now, in the current forecast, we're looking at about 1 percent after DSM and 1.9 percent before DSM.

So to recap, I think -- we don't try and forecast economic cycles, so major booms, busts, we try and forecast right down the middle.

So as I mentioned earlier, we try and do a P50, which is averaging these long-term economic events.

But I must add, the recession of '08/'09 was a very special event. And if you look at the history of BC Hydro load going back, and its predecessors going back to the 1930s, there's nothing like that in the historical record.

So we've never seen a case, where, for example, residential load it has flattened out. And we haven't seen a case where we've had such significant attrition, as happened with the pulp mills in 2008 to 2010.

So it -- it's made forecasting a challenge, but I think we've considered this in the forecasts going forward.

THE CHAIRMAN: You're going too fast, I think here.

COURT REPORTER: No, the Realtime stopped.

THE CHAIRMAN: The what stopped?
COURT REPORTER: The technology.
SPEAKER: Technology problems.
THE CHAIRMAN: Oh.
COURT REPORTER: A technology problem.
THE CHAIRMAN: Oh.
COURT REPORTER: Do you mind if you give us a minute?
THE CHAIRMAN: Yes.

It isn't you, it's the machinery. Hang on.

Maybe while we're waiting, I could just assure everybody that Madame lives in Nova Scotia and not Quebec. And it is Nova Scotia Power whose delivery was impugned before lunch.

(Stenography team rectifying technical issue)

THE CHAIRMAN: We're working there?

Say something, Mr. Ince.

MR. DAVID INCE: Testing.
THE CHAIRMAN: Okay. We're back online.

And you were saying (Reading from Realtime draft transcript):

"So what happened with the forecast

versus the actuals, we have -- so the history I'm familiar with --"

Blank.

MR. DAVID INCE: Yes.

So the history with, let's say, going back to the mid-2000s, we were criticized for underforecasting, that the good economic times -- actually, the forecast was excessively low compared to the actuals that occurred, and that abruptly changed in 2008 with the great recession.

And after that, for a period of two to three years, we were underforecasting -- or, sorry, overforecasting. And I think that's one of the hazards of forecasting, is that this was a profound economic event.

And the other agency, such as the banks and, in fact, the other governments did -- were subject to the same effects with respect to forecasts of GDP, and -- so it wasn't just BC Hydro in terms of its forecasts; it -- it was a profound event, that, you know, really changed the forecasting horizon.

So our current forecasts, we're looking at .9 percent annual compounded growth. And that's compared to -- before the recession, 3 to 2 percent

range. That's the combination of the aggressive DSM targets, but also a recognition that -- in the forecasting community, there's the terminology of the new normal. And it's a recognition that economic growth is probably going to be lower than it was pre-recession.

And also aging demographics. So we're expecting a lower participation of the workforce, lower GDP as a result of aging demographics, the baby boomers; less people working.

So we would like to consider all those factors in the forecast, not just population. But there's a number of -- a number of issues that impact the forecast.

With respect to the forecast accuracy to date, this was a forecast that was prepared in 2012, that's underpinning the Site C, and we're tracking well within 1 percent accuracy in our fiscal 14 to date.

And I'm pleased to say the industrial forecast is -- is tracking quite closely, that's always an area of uncertainty in the forecast because the vagaries of commodity prices and foreign markets. So, to a large extent, our forecast is dependent on foreign markets that are

really out of control of the pulp and paper sector or from the forestry sector.

And so we're pleased to see that our industrial forecast, in particular, is tracking well because that's always the subject of considerable variability.

THE CHAIRMAN: Yes, this diagram is an amalgam of a large number of U.S. utilities; is it? And reported by the EIA.

MR. DAVID INCE: It's my understanding that this is just the energy information administration. Their staff forecast of the whole United States. So utility.

THE CHAIRMAN: It's the staff forecast of the EIA. Okay. I'm glad you're better than that, being within 1 percent. That -- you say you've been within 1 percent of the actuals now for several years since recovery --

MR. DAVID INCE: To -- to be correct, that this forecast that underpins the Site C application, the 2012 forecast is tracking within 1 percent of actual loads in this fiscal year to date.

THE CHAIRMAN: Okay, that's good. Thank you.

Let's go on to Question 3.

Who wants to answer that one?

For those who are on the phones and can't see the question, it is:

> "Whether or not Hydro and the IPPs should use the same cost of capital?"

And noting that there had been a change in BCUC policy, or at least Hydro policy agreed to by BCUC?

MR. RANDY REIMANN: Sorry. Just trying to catch up to what exactly the question was here.

And so the basis for the change -- and I think this was originally referring to about an IR that had talked about what we had done in 2006: integrated electricity plan and the long-term acquisition plan. I think that's the change it's talking about.

And so in the application that we made to the BC Utilities Commission, in that 2006 application, we had done some project evaluation evidence. And an initial position that we put in there was to suggest that maybe all resources should be

considered on a level playing field.

And in the decision and after the discussion and the information requests at that process, the Commission's direction to us was that it wasn't Hydro's job to level the playing field. But if there was an advantage for our ratepayers, by having utility financing, that that should be recognized and taken advantage of.

And so since 2006, we have been then trying to be more accurate to both what Hydro's financing costs are, and what the IPPs are.

The way we've dealt with the risk, I guess, is to look at the different discount -- or cost of capital. We did that sensitivity test where the differential to us was 5 percent for Hydro. There's a real WACC in 7 percent for the IPPs.

THE CHAIRMAN: Yes, but -- I mean, that's old territory. And, as you know, there is an argument that says that Hydro's cost of borrowing does not account for the risk to the taxpayer, that you accept on behalf of all of us when you're the entrepreneur and so on.

And that the other items that the BCUC cite, that their decision was the same discount rate that should be applied to all resource options

regardless of who develops them.

MR. RANDY REIMANN: Right. And so the distinction, I think, is between the cost of capital that you would use to determine what the cash flows are that you put into your analysis versus the discounting of those cash flows then to determine a PV value.

THE CHAIRMAN: Yeah.

MR. RANDY REIMANN: So we have one discount rate.

THE CHAIRMAN: If we think of the discount rate and a WACC as being separate concepts.

MR. RANDY REIMANN: Right. So we do use one discount rate for all the cash flows.

THE CHAIRMAN: Okay.

Okay. I found that point confusing in my reading, I must say. You use a single discount rate for comparison of all alternatives?

MR. RANDY REIMANN: That's correct --

THE CHAIRMAN: You're not using a differential WACC.

MR. RANDY REIMANN: Right.

So we -- we break the analysis down into two stages: the first part being, so what is the entity's cost of capital that they would seek to recover on a particular resource.

THE CHAIRMAN: No, that's a -- that's a -- that's what you would use for calculating rates and making a rate application and so on.

For the economics of alternatives, as near as never, you should be using the same discount rate regardless of who the proponent is.

MR. RANDY REIMANN: Yes. The difference between the discount rate and the cost of capital to determine what the cash flow is.

So when we're creating these portfolios, we time the resources. And when a resource comes in, this is the cost of buying or building that resource.

THE CHAIRMAN: Yes. Yeah, my point is that I think that you're confounding financial and economic considerations.

MR. RANDY REIMANN: Well -- yeah. I mean, I -- I think this gets back a little bit to where we were in December about the idea of using different -- like, I -- I've seen different things where people suggest that you should be using market rates of equity and market risk assessments for projects all the way up to social discount rates, and we've kind of landed somewhat in between.

THE CHAIRMAN: That may be the problem. I

mean, classically, what you would do would be to select the attractive alternatives on an economic basis, and that is without accounting for the nature of the proponent and so on and so forth, but you would account for risks inherent to the project, not inherent the proponent.

And that would give you a ranking. And then you choose the most attractive ones or so, and then do a financial analysis.

But I think you're right. I think that you kind of run them together.

MR. RANDY REIMANN: Well -- and -- and that was the discussion that we had with the BC Utilities Commission. And what they suggested was if there was an advantage in financing a project, that was to the benefit of ratepayers, that we should recognize that. So that's where we've landed.

THE CHAIRMAN: Well, if that's what they wound up saying, then I think they are ignoring the assignment of project risk. And I think that that's an improper decision.

If -- if an IPP outfit, for example, is undertaking a project and they overrun; presumably, they eat the cost or the project never occurs.

In the case of Hydro, if you were undertaking

the same project, and you overran, the ratepayers would pay the cost.

So there is a risk there which is not the same necessarily, but it would take an awful lot of analysis to tease out just what that ought to be.

MR. RANDY REIMANN: Yeah. And, again, I guess -- so we -- we did -- we were -- we did discuss and we were told that difference in WACCs for the cash flows was appropriate. And that if you were then wanting to look at uncertainty or risks, that you could do those by doing sensitivity analyses.

And think that's what we started to do is we were then looking at the costs of the project versus the costs of the IPPs and the change in the discount rates -- or the change in the WACC. Sorry.

THE CHAIRMAN: I may be a bit sensitive to the point because I've worked both as an economist and as a banker. But I think we may have pushed that one as far as we can. Let's go on.

Question 4.

MR. CHRIS O'RILEY: Mr. Chair, I'll take that.

So as context in my role as being in charge of generation, I'm also responsible for our generation capital program. So excluding the

Site C project.

And we've got right now about 100 projects that we're doing, which total about $4 billion in -- in budget that's been allocated to me.

And those range from projects in the million dollars or so up -- to the largest one is the John Hart's development project, which is about a billion dollars.

And there are three projects in the range of between 500 and 1 billion, and those are John Hart, Mica 5 and 6 capacity, and Ruskin re-development.

And most of our work is refurbishment work of existing equipment, and, what we call, Brownfield. So kind of messy.

We have done and finished, on my watch, about 200 projects over the last seven years. And -- and I'm quite involved in those projects and report every quarter to the board on our progress.

Our estimating philosophy for the bulk of our portfolio -- and Mr. Savidant can talk about how it's applied to Site C, but our estimating philosophy is to use this 50 percentile concept.

So we estimate projects at a level such that 50 percent of them should come in under and 50 percent should come in over.

And the reason that -- that was a deliberate decision that was taken by our board a number of years ago to avoid the inclusion of -- of additional contingency in projects, and to -- to just to make sure we're being as sharp as possible.

And we benchmark our performance against the first implementation estimate for the project, so that's the estimate we take at the go/no-go point for the project. And we report on that annually on a portfolio basis to the board, and we do this for generation projects and transmission projects.

And I would say we have had good performance overall when you look at the -- the portfolio on cost and schedule. We've also had very good performance on quality and safety outcomes and environmental outcomes, which we also pay a lot of attention to.

We received the submission from the Boughton law firm, and -- and there were a number of -- of errors in the document, which is understandable because there's lots of numbers out there when it comes to -- to projects. And I'm not being critical about that.

So we have provided some corrected numbers, which we have on a table. And the punch line for

that is for the generation projects, in excess of $50 million, for the ones that had been completed, we are within 3.1 percent of the -- the budget that was -- that was identified. And if you add in the -- the -- completed and in-progress projects, over $50 million; we're within .3 percent on the -- on the generation side. And we have similar figures for transmission on the -- on the chart.

Part of the question was to reconcile with the 73 percent figure in the -- in the government review document. And what the government did is they -- they picked a subset of projects over a relatively short horizon; it was not much more than a year, and found that we were under budget 73 percent of the time. And -- they actually intended that to be a -- a criticism. The -- the great thing about projects is you can't win either way.

And the criticism was that we had so-called "fat estimates" in the -- in the -- budgets, so -- and I -- I think the response to that was you are going to see -- if you pick out subsets of projects, you're going to see more variability in the -- in the estimate.

So we have been, you know, stepping back. We

had been ramping up our -- our capital delivery program over the last ten years or so, and we're -- we're doing about $2 billion a year of projects as a company, including generation, transmission, distribution, and -- and some technology projects.

And we have -- we have significantly ramped up our capability to -- to deliver projects, including the management systems that go around that.

So I -- I do take quite personally the criticism of project management capability, and it's -- it's a fairly easy target because you can always pick out projects. And when you've got hundreds of projects, there's always the odd one that has challenges.

But I think what we would propose is to put on the record the updated table, and -- and we think that supports our -- our solid performance as a project delivery organization.

THE CHAIRMAN: Yes, please. That is important.

In my comment last December, before you got here, was that if you guys could keep delivering like that, we'd put you in charge of acquiring fighter aircraft.

MR. CHRIS O'RILEY: So I've got Question 5.

And this relates to the non-Treaty storage agreement. And I -- I want to say with the greatest respect to the -- the law firm, the Boughton law firm, that they have, I think, completely misunderstood the non-Treaty storage agreement. And -- and so it's difficult to address their points directly, but -- but I will -- I will try.

And I -- I do say that with the utmost graciousness because the non-Treaty storage agreement is probably the -- one of the two or three most complicated things you're going to find in BC Hydro. And that is saying something.

THE CHAIRMAN: You can take it for granted that the panel doesn't understand it, so ...

MR. CHRIS O'RILEY: Yeah. So I'm not going to get -- get into that.

But at a high level, the non-Treaty storage agreement is a co-ordination agreement between BC Hydro and Bonneville Power about how flows are managed, and it's necessary on the Columbia River. And it's necessary to take full advantage of the extra storage that was built at Mica Dam, the extra five million acre feet of storage that was built

over and up of what was required under the Columbia River Treaty.

So what I think is relevant for the proceeding and the -- and the panel is -- is that the full capability, the absolute capability of the Columbia generation system, including the capacity and the energy at Mica, and including the benefits, the beneficial impacts of the non-Treaty storage, are included in all the portfolios that are under consideration.

There is no capacity that's been held back from any of the portfolios preferentially.

So all, currently, 1,800 megawatts of Mica capacity is all in the portfolios.

And when we finish the projects, to upgrade Mica, all 2,800 megawatts will be all in all the portfolios, so there's nothing that's been held back.

And I should note that the non-Treaty storage agreement expires -- current agreement; we've had a number over the careers, expires in 2024. And -- and that date was picked because it's coincident with the earliest termination date for the Columbia River Treaty.

It's -- its my expectation that regardless of

what happens with the Columbia River Treaty, we'll re-negotiate some form of non-Treaty storage agreement, and the benefits of that have been, assumed to be included, beyond 2024. And we think that's a reasonable assumption.

THE CHAIRMAN: I don't want to get into any of the details of an ongoing negotiation here, but do I understand it correctly that Hydro is effectively leading the Canadian side on this?

MR. CHRIS O'RILEY: Well, that would be giving us too much credit.

THE CHAIRMAN: No, I mean, leaving aside the egos of governments, you guys are actually leading on this?

MR. CHRIS O'RILEY: BC Hydro is providing technical support to a very able team in the Province that is leading the negotiations, and the discussions around the Columbia River Treaty with the U.S., so we are very involved.

Ms. Kurschner, who you met, is the coordinator for -- her title under the Treaty is coordinator of the Canadian Entity. I'm the Chair of the Canadian Entity. And so we engage with the Province on the analysis and -- and negotiating positions around the Treaty. And that work is

under way.

THE CHAIRMAN: Good. What's the timetable? Or do you know yet?

MR. CHRIS O'RILEY: The earliest date at which the Treaty can be terminated is -- is 2014. And I think -- I believe that's the fall of 2014.

THE CHAIRMAN: September 16th, says Mr. Mattison.

MR. CHRIS O'RILEY: September 16th. I will -- I will take Mr. Mattison's word on that.

That's a somewhat artificial date because you can always terminate in 2015, and have the contract -- or agreement terminate in 2025.

So what -- what BC -- BC and Canada have -- have done is put out a position on it, and as have the United States. And you can appreciate they are -- they are somewhat far apart.

I think all parties have concluded that there's a lot of benefits to the Treaty, and it would be capricious to terminate early.

So I think, most likely, there will be a much slower process to seek any mutually beneficial changes to the arrangements within the Treaty itself.

So we're not expecting any big decisions in

-- in the next little while.

THE CHAIRMAN: So, as Bernard Shaw said to the lady, we settled to principle and it's a matter of price?

MR. CHRIS O'RILEY: I -- I think what we've concluded is we -- there is tremendous value in the -- in the power and the flood control benefits, and, particularly, the flood control benefits that the U.S. enjoys, and -- and -- you know, they are going to want to carry those on more likely than -- than not.

THE CHAIRMAN: And there is no pressing deadlines in all of this; people will keep talking until you come to agreement?

MR. CHRIS O'RILEY: Yeah. The most pressing deadline -- and I say that because it's not that pressing -- is the fall of 2014. And I -- I think that the importance of that deadline has diminished somewhat.

THE CHAIRMAN: Okay. Thank you for that.

And thanks for the explanation on non-Treaty storage.

What's our next question?

Yes.

Broughton and others brought up the question

of the Kleana project.

MR. RANDY REIMANN: So we have spent some time working with the proponent, and looking at the Kleana project, and I guess a starting point for this is just --

THE CHAIRMAN: Closer to your mic, please.

MR. RANDY REIMANN: A starting point for this would be to say that the Kleana project and -- and the Site C project are not similar projects in any way, shape, or form.

The Kleana project doesn't -- has very little dependable capacity, and it has no storage. And so it -- it doesn't provide the same product that we would get from Site C. So that -- that was part, I think, of the question to say that it's comparable or -- or attractive.

I guess the other -- so as we looked at this, we had taken a look at what the unit energy cost was, and -- and the position in the Broughon IR was to say that looking at a dollars-per-kilowatt basis, it looks attractive.

But given the energy profile it has and what it delivers, that's really the wrong metric. And -- and we get into that a bit in the clean energy rebuttal; they had made the same sort of point,

that on a dollar-per-kilowatt basis, this run-of-river looks good. But that's really the wrong metric.

And if -- if you take a look at what those projects deliver in terms of a firm energy product, we find that the price of the project, the Site C project versus the Kleana, is much different. And a rough assessment of this project has the adjusted unit energy cost of it north of $140 per megawatt hour.

So in terms of the analysis that we've done in the portfolio PV analysis, the Kleana project is not substantially different than the run-of-river options that we'd shown in there. A similar sort of price; a similar sort of profile in terms of the energy delivered.

And, in fact, what we see is that wind is the preferred resource, and -- and that's somewhat different than our last call, but, as we've all discussed, the wind projects have been coming down in cost. And we are now predicting that wind would be the more successful resource, and that's what our portfolio selected.

So the bottom line is Kleana -- we -- we rarely go -- and I think I've made this point

before -- we rarely include individual projects because, typically, proponents won't give us their actual financial and technical information in an open process that we can then share. So we don't tend to model individual projects, we tend to model class of projects, and try to do assessments that are similar. And we've had a reasonably good track record with that.

So bottom line is no different than what we've modelled, and it wouldn't have changed the outcomes of the portfolios. So ...

MR. CHRIS O'RILEY: Yeah, if I could add. I think it was in the -- the Boughton Submission, there was discussion about the flexibility to better match the supply to load with products like Kleana and other IPP contracts. And -- and while we acknowledge that is -- is true to some extent; in practice, we should be careful not to overstate that.

Our present value model assumes perfect foresight in matching -- bringing IPP contracts on to match the load. And that's, frankly, a generous assumption for the clean portfolio.

We do -- when we design a call, we typically have to size that at a certain level so we can

capture the larger resources like Kleana. And -- and achieve a scale benefits that come with that. So you end up with this mismatch in -- in supply and demand, even with these portfolios.

And we have seen, at various times, pressure to advance calls in support of the -- the economic development objective of -- and aspect of the clean sector. And that can tend to leave you with a bit of an imbalance between supply and demand.

And we also know that once a call is started, even on a contingent basis, it can be difficult to -- to turn it down or slow it down once they -- once it's under way.

So we -- even with the clean generation, we can't plan to a head of a pin, and you can end up with surpluses and -- that you have to market, and sometimes at really difficult times of year.

MR. MIKE SAVIDANT: Your question also asked a bit about the environmental impact of the Kleana project. And, as Randy said, they are not directly comparable. So you're not going to look at it exactly the same way. But I -- I was a little bit surprised by the submission because early on in this process, we were looking at portfolios prior to the wind cost decrease, that Mr. Reimann talked

about, and they were much more -- they had a more run-of-river to them. And what we actually saw in the portfolios was a much larger terrestrial footprint.

So what -- what the submission doesn't include -- and -- and I can't talk to whether or not their -- their footprint at site is appropriate or not, I don't know, but what it doesn't include are the transmission lines and the roads to get there.

So when you look at IPP resources, wind and run-of-river resources, a lot of the footprint comes from how you get there. How you get there in terms of roads. How you get the power out of there in terms of transmission lines.

And when you look at run-of-river, run-of-river tends to be in more remote locations, have longer -- longer requirements. Wind in the Peace has shorter transmission and road requirements than, say, run-of-river in -- in a range of places.

In the early portfolios we looked at, we saw, you know, per unit of firm energy delivered; run-of-river tended to have more of a footprint than Site C. Wind is lower. But run-of-river did

have a higher footprint per unit of firm energy delivered.

What you see in the current portfolios is really what wind does, and so that's why we're talking about it in the EIS, that your footprint, a lot of the attributes does tend to depend on where -- what resources you select in your call and where they are located.

THE CHAIRMAN: Thank you, that's very helpful. And I suppose it's not the first time ever that someone has used a hearing to gain a marketing advantage.

But that aside, it raises the interesting question of suppose -- as you say, you've replaced Burrard now. And then you build Site C. What do you do next?

Too far away to think about?

MS. SUSAN YURKOVICH: Mr. O'Riley talked about some of the things that we are pursuing. And, in fact, in these hearings, we have heard about geothermal and solar and tidal and some other options.

While at this juncture, some of those are not yet proven technologies; they can't be reliably put into our planning stack.

As we noted, we are very interested in those

moving along. There are a number of folks who have noted that this is the last project that is in our planning stack to develop, and as the project -- as the Province continues to grow, we will need additional resources, both energy and capacity. And, you know, as we move forward, they need to come to a place where they are proven, and, hopefully, where we can reliably have them to meet the needs of our Province and our customers.

THE CHAIRMAN: Understand. There's no sense taking decisions before one has to.

Go to question 13, please. Geothermal.

"In 1983, in the last Site C proceeding, the Utilities Commission said you ought to study geothermal in north-eastern BC; have you done so? Are you doing so?"

MR. RANDY REIMANN: Thanks Chris.

Yeah, we are, actually. We are studying. And, interestingly, given some of the evidence that's been provided in this process, we, in fact, are together with the provincial government, are

funding the favourability map that is studying those geothermal resources that CanGEA referenced in -- in their information.

And so -- yeah. In a more general sense, ever since I think the 2002 energy plan or energy policy, Hydro's role is not to do R&D, and to do research development.

We were expected to continue to do the two river projects and maintain them. But all other was expected to be put to the independent power producers to explore and develop those.

And any R&D funding that we sort of had before to prove out or getting into those technologies at that point, we really shifted away from that.

But having said that, we have been interested, I guess, as a first line of expected response was that we had hoped that IPPs would get into developing the geothermal. And after a number of acquisition processes -- South Meager Creek was -- was with western geothermal, and we had had some good hopes that that was going to be bid on because we would love to see some energy resources with a good amount of dependable capacity.

So it would be a very attractive resource to

us. But it didn't go up. They ended up having, as I think was explained in -- in attachment the latest CanGEA filing, but they had problems with fractures and not being able to retain any of the fluids of the drilling that they'd done up there. And it just sort of highlights for us that this drilling part of geothermal is -- is still a high-risk thing.

So we -- we still had interests and thought, well, we would like to advance this. So the two things that we have or are doing. One is is funding that favourability map, that includes the exploration of that sedimentary basin in the northeast. And that's in process. We haven't seen the results of that yet, but we'll consider it in due course.

And we've also funded a person to work with the ministry to help think our way through how permitting or whatever issues may be there in terms of stalling these entities.

And so at the end of the day, we still see that there's significant risk for where you have to do greenfield drilling. And our perception is is that most of the geothermal that's going on in the world is in proven areas where they understand the

geology and its expansions to existing, there is a bit of greenfield.

But with respect to the heat in the northeast and the saline there. We had looked at that, and given it some thought. And a rough unit energy cost of that sort of resource was looking to be in the area of $130 per megawatt hour, was kind of our sense. And that's a plant-gate price, that's not actually getting it connected into the transmission system and delivered.

And -- and it's interesting that there was nothing in the CanGEA report about pricing or costs of this stuff, but ...

So it's our expectation that it was expensive and still somewhat remote. And so we are just waiting to see the results of that analysis.

THE CHAIRMAN: I wrote an article about Canadian renewal energy prospects back in the 1970s, and we were talking about Meager Creek back then.

What is the current level of effort on geothermal? Are we talking a 100,000 a year or a million or what?

MR. RANDY REIMANN: For Hydro's --

THE CHAIRMAN: For Hydro.

MR. RANDY REIMANN: Yeah. So, our funding? No. It's -- it's under $100,000. And, again, we don't really have funding to do R&D. That's -- we're not expected to do that. In fact, we're expected not to do that.

THE CHAIRMAN: Where does that expectation come from? Is that the board or the government or what?

MR. RANDY REIMANN: That was in the 2002 Energy Plan.

THE CHAIRMAN: Are you trying to goose along Geoscience BC or NRCan to assist with the exploration?

MR. RANDY REIMANN: I'm not sure we've taken any definitive steps towards trying to have those entities -- we -- Geoscience BC is, in fact, the other funder of the favourability map, though.

So I guess we'll have to see what that comes up with, and if there's some merits that are advancing that.

THE CHAIRMAN: You say that there's not much experience with putting holes in the ground, and, yet, the story that we've heard of and the maps that we've seen up here suggests that northeast BC is a veritable pin cushion.

Do you collaborate with or query folks in the gas industry what they are finding?

MR. RANDY REIMANN: So let me distinguish the two types of resources, as we understand it.

There's the high temperature, either flash or binary technology, but it's trying to really get into the hotspots. And those higher-quality temperature sites are unproven and undrilled.

My understanding of the sedimentary basin that we're looking up here and the water is in the 140-degree-Celsius range.

And so my understanding of that is that that -- that is a low-grade heat. And if successful, the plant would be in the 130-dollar-per-megawatt-hour range.

So it's -- it's north of what we'd be paying for the wind; albeit, it has the capacity benefit.

So it's -- it's expensive, but -- but there's other issues, as I understand it as well, is that the -- the tenure to drill and develop these sort of facilities actually sits with the oil and gas producers.

And if -- if -- and I think the concern there is you don't want to be giving drilling rights to any other entity that could then compromise the way

the oil and gas is recovered.

And so I -- I think it sits with the oil and gas. And to date, we haven't had a lot of discussions, primarily, because it seems to be a more expensive resource. But that's not their primary business.

So when the CanGEA proposed this favourability map, I think we funded it, and Geoscience BC funded it. I don't think any of the IPPs participated in that funding, nor did they get any oil and gas developers to do it.

So we haven't seen a lot of interest, but, honestly, haven't tried to go up there and --

THE CHAIRMAN: But you haven't been out beating the bushes for it either. Yeah.

No, it is interesting. I mean, the oil and gas companies have certainly got commercially-sharp pencils, and if they saw some capability for a joint production effort, they might be interested.

But I do take the point about low-quality heat. Lower-temperature heat up here, as far as we know it. It's kind of like a CANDU reactor.

MR. RANDY REIMANN: Yeah. And I guess we've seen and had that question about Alberta has got all these wonderful resources as well, but as far as we

know, no geothermal has been developed in Alberta. There was one project we had heard of that didn't get taken to completion.

THE CHAIRMAN: And the igneous prospects in the southern coast range have not been drilled in the last 30 years?

MR. RANDY REIMANN: I'm mostly aware of the Meager Creek site. I'm not sure how much else has been done. Not a lot, as far as I know. Not anybody that I've heard from.

THE CHAIRMAN: What is your mandate in terms of investigating novel energy sources?

At one point in some material I was reading, you were talking about keeping an eye on all kinds of technology developments that were happening out there.

What do you do about that? And how much effort do you spend scanning that horizon?

MS. SUSAN YURKOVICH: Thank you, Mr. Chair.

So I would just note with respect to the discussion around geothermal, and, in fact, other new alternative sources of energy, the 2003 Energy Plan really sets out that Hydro would utilize its expertise in large hydro and undertake those projects. And then for all other independent power

projects, geothermal, wind, run-of-river, any of those other technologies, that that would be for the private sector to provide.

Because we are -- we are interested in geothermal, I think despite the fact that our -- the BCUC in our '05/'06 revenue requirement application, specifically, excluded us undertaking R&D, we do think it's important to advance this because it could be one of those sources that meets the need going forward. And so we are interested in that and funded the study, as Mr. Reimann indicated.

I think we spend a lot of time in our demand-side management programs thinking, looking around and scanning the globe for initiatives around conservation and energy efficiency, which is clearly a part of our mandate, and where we are choosing to get the vast -- meet the vast majority of our future load growth. And in that area, we have a lot of work under way and people engaged with other jurisdictions to determine -- to look for new technologies and new programs that we could implement.

THE CHAIRMAN: 2005 or 2006 BCUC was faithfully applying the government's policy and

telling you not to do it, more or less?

MS. SUSAN YURKOVICH: Yes.

MR. CHRIS O'RILEY: Yeah, I -- I think they didn't like us spending the money. I think -- I don't think it was that big of a conversation. Utility commissions have a hard time with R&D dollars, traditionally.

MR. RANDY REIMANN: The one other, I think, area where the government was looking at trying to enhance or develop some of these technologies was by looking at feed-in tariffs. And -- and they did give that some consideration, but, ultimately, decided that that can be an expensive route, and they decided that they didn't think it was beneficial to fund that.

THE CHAIRMAN: As a former resident of Ontario, I applaud that.

Okay. Back to 7, now, I think is where we -- yes, 7.

MR. CHRIS O'RILEY: And I think we addressed this question. This was the question of how much non-firm hydro we were including in the portfolio as -- as firm.

THE CHAIRMAN: No, it's a question about critical versus average years.

MR. CHRIS O'RILEY: Well -- okay. Well, I'll have a go at it, then.

So with our heritage hydro, we look at the critical water, and then we have an allowance for 4,100 gigawatt hours of -- of market, which is another way of saying we -- we plan to average. So, I -- you know, you could look at that both ways.

When it comes to the -- the non-firm run -- well, when it comes to run-of-river IPP, we -- we start with the contractual firm and the contractual non-firm, and then we put that into our -- our mix of IPP contracts and with the system. And we calculate a firm reliance, which is greater than the contracted firm.

THE CHAIRMAN: "Firm" is a function of the amount of water that's flowing?

MR. CHRIS O'RILEY: It is. It's also --

THE CHAIRMAN: Yes. And following the review by the Deputy Ministers of a year or two ago, Hydro moved back from using critical water as its definition for self-sufficiency and other purposes to using average water, but I understand you did not do the same thing for IPPs. Is that correct?

MR. CHRIS O'RILEY: For run-of-river hydro IPPs, that is correct. For wind, we use average. For biomass, we use average.

THE CHAIRMAN: Yeah, yeah. It's the waterpower I'm interested in.

MR. CHRIS O'RILEY: Yeah. So it -- it's the issue of the -- the 15 percent, which is the -- what we calculate the -- the non-firm percentage to be on a portfolio basis. And that's the difference between 85 percent, which we call firm on a portfolio basis, and the 100 percent, which equals average.

So -- so this is the question of the -- the 15 percent we talked about this morning.

And our -- the -- the reason we can't rely on that is it tends to come in the freshet. And we don't have the capability to store and move that into other times of the year. So that's why we're -- that's why we're distinguishing between the -- the run-of-river IPP and other resources like wind.

THE CHAIRMAN: Okay. Understood.

Next. Yeah.

MR. MIKE SAVIDANT: So, Mr. Chair, we've provided the table in -- in the slide deck, slide 7, that

shows the revenue requirements attributable to Site C for the first several years. I can take you through how -- how that's determined.

Sorry, we lost our slide operator.

Slide 7.

THE CHAIRMAN: Slide 7 is historic prices.

MR. MIKE SAVIDANT: Not handout 7, slide 7. In the slide deck.

THE CHAIRMAN: We've got two decks here, which is what's confusing.

MR. MIKE SAVIDANT: So there -- there's three main components of that revenue requirement. We've shown it here for the first four years, those are in nominal dollars.

And then we have a hand-out -- and I won't get you to turn back to that right away, but we have a hand-out that shows it for the 70-year evaluation period.

Amortization is the first component; that is, effectively, the $7.9 billion capital cost amortized -- a straight-line amortization over a 70-year period. You'll find 7.9 billion divided by 70 is 113.

Then we look at the finance charges. So since the change, the November 26th announcement,

this project is effectively being financed -- the incremental financing for this is at debt, the cost of debt, which, as I mentioned earlier, we've assumed is just under 5 percent in the long-term cost of debt.

So for each year, you're going to have a declining capital balance, and you evaluate your interest financing charge at 5 -- 4.82 percent on that declining capital balance.

So 7.9 billion times, roughly, 5 percent, you're in the $390 million range.

I'll mention fiscal 24 is half-year rule, so that's why it's lower than everything else.

Then you get into operating costs, and there's a few components of that. There's the -- there's the actual operations and maintenance for the plant. That's, roughly, 7.5 million in real dollars, that would be escalated by inflation.

You would have water rentals. Water rentals used to be indexed to rates, but they are now indexed to inflation as well. So they are roughly thirty -- I think they're in the low 30s of millions of dollars, and they would increase also at inflation.

And then you have grants in lieu and school

taxes, which have been talked about previously in this -- in this hearing.

So those three components are the major components of the revenue requirements.

What we've also shown on this table to answer I believe your question -- one of your six questions is what the -- what the revenues that would come in from the surplus would be.

So the net revenue requirement is the 341 million. That's included in the rate graph that we show, the rate-smoothing graph that we've shown there.

So that -- that would have an impact on rates for a few years, but it would decline. And after, roughly, ten years, it would be reducing rates for the rest of the operating life of the project.

I -- I will note. It -- it's a different analysis in the NPV analyses. We have the UEC analysis. The UEC is evaluated at -- it includes utility risk and the cost of equity. It includes everything like that.

On handout 4, we've kind of indicating -- indicated the difference between those, the revenue requirement tends to be lower than the UEC very quickly after the project comes in to service.

MS. DANIELLE MELCHOIR: Would you like me to put that handout up?

No.

THE CHAIRMAN: Sorry, I can't hear you.

MS. DANIELLE MELCHOIR: I can put the handout up if you wanted to look at that?

THE CHAIRMAN: Yes. Thank you.

MS. DANIELLE MELCHOIR: Thank you.

That one?

THE CHAIRMAN: Okay, good. Can we go on to question 9, please.

MR. MIKE SAVIDANT: So the accounting treatment of losses is, to some extent, shown in the revenue requirement. So what happens when a project comes into service, the costs of that project are recovered from ratepayers.

So that total cost, which -- and then the cost is -- the cost, whether or not the electricity is being exported or going to ratepayers, would be recovered.

During the period where there's the short-term surplus, there is revenue component as well that will also go into -- will reduce rates.

After that surplus period, there won't be -- I mean, that surplus declines over time; it

eventually goes to zero.

THE CHAIRMAN: Well, that surplus depends who you're being able to flog it at a nice price.

MR. MIKE SAVIDANT: Which, we believe, we'll be able to do.

And so as that surplus declines, then it -- you don't see a revenue, what you're doing is you're spreading those costs out over an expanded customer base. And that's all reflected in the rate analysis.

THE CHAIRMAN: All right. So if you're -- and I'm -- I'll see if I understand you.

If your assumption about export prices doesn't hold up, then that means simply that the amounts that would be recovered from ratepayers would rise; is that right?

MR. MIKE SAVIDANT: That's correct.

THE CHAIRMAN: Okay. If -- you know, you've spent about a quarter billion on Site C so far. And you'll have a few more dollars out before Halloween when Ministers will make their decision. What happens then if Ministers decide the project doesn't go ahead?

MS. SUSAN YURKOVICH: If the project was decided that they would put it down and -- and it would be

abandoned, effectively, it would go to the bottom line of the Province.

THE CHAIRMAN: It would be expensed in this year, in effect?

MR. MIKE SAVIDANT: Sir, to some extent, that would be decided by the BCUC. We would have to go to a hearing.

I mean, the BCUC has overseen and approved both the Stage 1 and Stage 2 funding.

THE CHAIRMAN: M'mm-hmm.

MR. MIKE SAVIDANT: I -- I don't want to speculate on what they would actually do. I think there would be a likelihood that those would be recovered from ratepayers no matter what.

There's some question in terms of whether -- what would happen with the funding for this environmental assessment process Stage 3.

THE CHAIRMAN: You would always charge it to your mythical equity.

Okay. Question 10.

And, I confess, I'm a little confused on this. And I read some newspaper reports and something in one of your documents. The newspaper reports were suggesting that you had reduced expenditures on DSM, and one of your reports was

suggesting that, as a cash conservation measure, you were going to do it sometime in the next few years.

First off, what are the facts?

MS. SUSAN YURKOVICH: I'll let Mr. Reimann answer this question. But what we have done -- we are maintaining our expenditures at historic -- essentially, at the historic levels that -- of the last three years. We are reducing how quickly we expand, but we are keeping our target in place.

I'll let Mr. Reimann give you some more details.

MR. RANDY REIMANN: Thanks, Susan.

Yeah. So the exercise that we went through in the integrated resource plan was to address what costs could we minimize over the next three years, but still, essentially, keep cost-effective options on the table as we get out into the 2020 timeframe.

And -- and so as we looked at the demand-side management, as Susan's described, as -- we'd had a ramp-up that was going to be accelerating the activities on demand-side management faster than we have been historically. And we looked at that and said how much can we temper that?

And so what we landed on was that by,

essentially, maintaining the expenditures at the same rate as we've done the last four years, doing that for another three years, that we would still be able at the end of that period to ramp-up activity and get back to that same DSM targets, the DSM Option 2 gigawatt hour savings of 780 gigawatt hours by fiscal '21 --

THE CHAIRMAN: Yeah, so that -- in effect, what you're doing is postponing the expenditures and having a steeper ramp starting in year four, then get to where you otherwise would be at the cost perhaps of some gigawatt hours consumed in the short run that might not otherwise be; would that be a fair -- is that what you mean?

MR. RANDY REIMANN: Yeah, that's -- that's essentially it. And then, of course, as you get into doing a steeper ramp, it has the effect of increasing the risk of not meeting your targets, but we think it's manageable.

THE CHAIRMAN: I must say, when -- your talk about the risk of DSM, when the amount that you're allowed to spend on it is dictated by the Province; I understand why you think it's risky.

MR. RANDY REIMANN: So the -- I mean, the cost of the DSM programs, as a whole, are relatively

inexpensive. Our greater concern is whether or not we can actually convince everybody to do everything that we'd like them to. And so it really becomes almost more of a deliverability risk. How quickly can you change society's perspective?

To the extent -- like, the costs that we've predicted so far of what we think we can actually get people to do seems to be relatively cost-effective.

THE CHAIRMAN: Okay. Go on to the next one.

MR. RANDY REIMANN: So on the LGS rates, I guess the trick here is is that we've had the LGS rates out there for a little better than a year. And we've actually done some review of it, and reported that back to the Commission. And what we found is that the LGS rates are underperforming what we'd anticipated of the response that we'd see, maybe to a third of what we'd anticipated.

And -- and, thus far, with the MGS, or medium general service, we haven't been able to sort of discern any effect.

So we are kind of in the process now of trying to understand. So exactly why is that? And one of the things we're looking at is the complexity of the rate structure itself.

And as we went out and surveyed people on this, came to the realization that not a lot of them were even aware of the rate. So we need to do more education, and maybe some simplification.

We may be a little aggressive in terms of what we're counting on in our DSM plans from rates.

THE CHAIRMAN: Okay, I understand what you're talking about. From the response to the question, it appeared quite paradoxical.

12.

MR. RANDY REIMANN: So this kind of carries on from the prior question. When we -- when we design in our -- our DSM programs, and, for instance, the DSM targeted Option 2, what we do is we give our DSM planners a price signal. And we ask them.

So using that as the maximum that you'd be willing to pay for incremental savings, how would you go about designing programs. And -- and the target that we'd given them for the DSM Option 2 is $100 a megawatt hour. And so it's -- what you end up seeing reported a lot is for a particular target, all the savings -- and it's a weighted average of everything in it; when you start comparing between them, you start seeing that, no, we are going up the supply curve.

And so we'd done some analysis, the whole of all the DSM Option 3 versus Option 2 was maybe in the area of $75 a megawatt hour, but it was actually as a marginal price signal going up to $130 a megawatt hour.

So this -- this whole demand-side management, developing the programs and predicting customer response and -- and price signals and all this is quite a complex undertaking, but I guess we'd argue that we are pretty much taking it up.

And so in the IRP, what we've identified is that we think our long-run marginal cost is in the range of 85 to $100 a megawatt hour.

And in that range, the things that would show up as supply was both DSM up to a certain investment level and IPP renewals.

And so we're renewing them at whatever cost we can negotiate. And maybe not paying fully up to the long-run marginal cost, but ...

THE CHAIRMAN: Okay, that makes sense.

MR. RANDY REIMANN: Yeah.

THE CHAIRMAN: So everything that the Industrial Electricity Policy Review Task Force final report, a noun train of astounding length, recommended you're already doing; right?

MR. RANDY REIMANN: Essentially.
THE CHAIRMAN: Including for residential and commercial customers?
MR. RANDY REIMANN: So --
THE CHAIRMAN: The DSM target price that you give your planners, the marginal cost number is the same across all customer classes?
MR. RANDY REIMANN: Yes, generally. But in terms of an equity in -- of having all classes treated equally and all having the ability to reduce consumption to get the benefit of savings, we do get into some low-income programs that are above that. And so with that exception. But outside of that, yes, the three sectors are treated equally.
THE CHAIRMAN: Okay. Next one.

Oh, we did that one.

14.

MS. SUSAN YURKOVICH: Mr. Chair, if I might ask Melissa Holland to join us at the microphone, our director of projects for transmission and distribution for question 14.
THE CHAIRMAN: Great. Welcome.
MS. MELISSA HOLLAND: Thank you.

So I was here, you may recall, in December. So I'm back. Thank you.

And in December, I, in response, Madam Beaudet, to one of your questions. I talked about how BC Hydro does not have the powers to block access to Crown land, and what the project has -- has committed to do and -- and has very successfully done in other areas of the Province is work with the Province to put in place gates or other mechanisms to -- to limit access.

We have seen success in using gates to reduce access when that is undertaken typically in combination with conservation officers to -- to enforce that. And I think you'll recall you -- you heard from -- I believe it was one of the counsellors of West Moberly that people just drive around gates. So a gate isn't the only -- the only solution.

But what we would like to continue to do is explore those opportunities, both with the Province and with communities, about how we can reduce -- reduce access.

In terms of the project itself, there are existing access roads that we will need to use for the purposes of -- of construction. Those access roads exist right now to maintain the existing transmission corridor.

And as we work our way through detailed design, and, again, with -- work with the communities, we believe we will be able to identify opportunities either where we can deactivate and reduce access to -- to the transmission corridor.

THE CHAIRMAN: I'm glad to hear that.

Are there opportunities, for example, to qualify West Mo and Saulteau citizens as conservation officers?

MS. MELLISA HOLLAND: I'm not sure that I'm familiar enough of what the training requirements are for those kind, but we could certainly take that away as an undertaking --

THE CHAIRMAN: We'll just let that sit out there as suggestion.

MS. MELLISA HOLLAND: Yeah.

THE CHAIRMAN: Okay.

MS. SUSAN YURKOVICH: Mr. Chair, if I might, we also, should we move forward to construction, will have a program, environmental monitoring, and it's -- we often -- we ensure those programs do include First Nations and expect we will do so on this project as well.

As far as the requirements for conservation officers, I think there may be -- I think there may

be some people here from the Province who would be better able to speak to that.

THE CHAIRMAN: Is Mr. Addison here?

MR. CHRIS ADDISON: Yes. Good afternoon.

The requirements to become a conservation officer are quite extensive. And we do have a couple programs in the region to encourage First Nations people to become involved in that program.

It requires interest among individuals as well. It's something that we've been interested in over time. We haven't moved a whole bunch of the programs too far forward recently, but it's -- but it's there as an option. But it -- but it does require the individual's interest as well.

It's quite an extensive training program. There's usually a Bachelor's degree required, all for a job that doesn't pay overly well, so ...

THE CHAIRMAN: Thank you.

I must say, I've often thought that we have people living in the mid-north who are looking for work and we have a requirement to look after the land and it seems to be moving in the right direction, but maybe a little slowly. Yeah.

MR. CHRIS ADDISON: I know. Conceptually, it really does seem like a good fit, so we're hopeful

about the future in that regard.

THE CHAIRMAN: And it's even possible that with Hydro taking an interest, this might accelerate it somewhat?

MR. CHRIS ADDISON: M'mm-hmm.

THE CHAIRMAN: Yeah. Thank you. Thank you both.

Oh, Madam.

MS. BEAUDET: You've addressed the existing roads. What about the road -- part of the road that you have to extend northeast of the transmission line when you widen the -- what you call the right-of-way? Would that be left as is to be used in the future? Or would you remove that?

MS. MELLISA HOLLAND: There are two parts to the construction for the transmission corridor. My understanding is that access to the corridor is already in place. And in some places, we do need to brush out or upgrade that existing access. And we can certainly discuss whether we -- again, with input from the communities -- whether we allow some of that access to re-grow in.

We aren't anticipating having to build any new roads to the corridor. Once you're in the corridor, there's several things that have to

occur: one is the wood has to come out. And the clearing is anticipated to be done during the winter.

And in that case, then, you don't have to bring -- you don't have to construct new roads because you're taking the wood out of -- out of -- out over frozen ground.

Then you have to construct the foundations and the towers and -- and do the stringing for the transmission line.

And for that, about 10 percent of the construction has to be done during the winter because of some very boggy ground that doesn't lend itself particularly well to -- to road construction.

And so that leaves you with sort of the other portions of the line. And in those portions, what we -- a typical construction practice would be to build, what we call, F-tracks; small, temporary tracks along the corridor that take you to tower sites. Typically, those are -- are de-activated. And they are temporary for the purposes of construction.

For maintenance and operation, you do want access to the corridor. It's the easiest way to

get in if something goes wrong. We do have areas in the Province where we have to fly crews in, but if there's a road in already, it's -- it's certainly preferable to -- to use that.

But, again, my -- my earlier comments, we do believe that there are some opportunities to reduce overall access to the -- to the corridor, and while the corridor will be cleared for construction, which opens up the corridor along its -- its length, we can de-activate some of those roads.

There isn't a continuous road that you build along the right-of-way to get to every tower site. You come into the line, you build a few towers there, you come in in a different area, you access a few more towers there. So there isn't, if you will, a road highway down the corridor that gets built.

MS. BEAUDET: Thank you.

THE CHAIRMAN: Do you still use herbicides along the right-of-ways?

MS. MELLISA HOLLAND: In the transmission vegetation management plan, there is a toolbox, if you will, of, I guess, tools that can be applied. We use things like mowers. We do do some treatment of very specific tall-growing or aggressive plants,

and that can be done with a -- with a herbicide application; typically, it's a stem treat.

Ideally, you want to, after you've cleared, encourage the growth of low-growing vegetation, which tends to prevent the tall trees from coming in.

We do have a vegetation management cycle that we go through to check for tall-growing trees and -- and so there's sort of a clearing -- clearing prescription.

So there's a number of different ways that we deal with vegetation in our rights-of-way.

THE CHAIRMAN: Is this -- is the program that you choose based on cost minimization or trying hard to avoid chemicals?

MS. MELLISA HOLLAND: I think it's based on a number of factors, and that includes terrain and where you can get equipment in.

It includes what kind of vegetation do you see growing there and how quickly does it -- does it grow. The -- the chemical aspect, we are part of the provincial program to deal with what kinds of herbicides are -- are safe to use in managing our -- our rights-of-way.

So there's a number of factors that go into

choosing what tool, and the tool kit you use to manage your vegetation.

THE CHAIRMAN: Thank you.

15.

Yeah. I think this was just a confusion. Or a clarification question. Who can speak to 15?

MR. MIKE SAVIDANT: I can answer it.

So when -- I'll note the 32.5 percent was prior to the November 26th announcement. We now expect that 20-year real dollar rate growth to be 21 percent.

Site C and other capital projects was included in it, both the -- both the 32.5 percent and the 21 percent. It's included in those numbers.

THE CHAIRMAN: Thank you.

16.

MR. RANDY REIMANN: So the answer to why four tables and not two is, yes, it was a clerical error. They -- they were just duplicated in there.

So there's two tables: there's an energy and a capacity table attached to this undertaking.

The other question is: what was different to what was shown in the final IRP? And the answer is that, as the government requested additional

strategy for the clean energy sector, the standing office program acquisition was bumped up to a nominal 150 gigawatt hour per year, which would deliver in the order of, after attrition and expected response --

THE CHAIRMAN: Okay. So we should read the final IRP, and ignore all the rest?

MR. RANDY REIMANN: Agreed.

THE CHAIRMAN: Thank you.

17.

MR. RANDY REIMANN: The ranges they are between the EIS and the IRP are the same ranges: 800 to 6,600 gigawatt hours.

What was in the IRP is a bit more emphasis on the expected range of 3,000 gigawatt hours. And so some of that was shown, but it's within the range and -- of what we showed in the EIS.

THE CHAIRMAN: Good.

18.

MR. CHRIS O'RILEY: So I have this.

The Skagit Valley Treaty profitability.

So just a reminder, this Treaty was signed in 1984 between Canada and the U.S. Canada on behalf of British Columbia. And under the Treaty, it voided a previous agreement that had been in place

between BC and -- and the U.S., that would have allowed the raising of the High Ross Dam by Seattle City Light and flooding back into Canada in the Skagit valley.

And under the Treaty, which covers an 80-year period: 1986 to 2065, Seattle would pay British Columbia the avoided-carrying cost of the higher dam, the so-called High Ross Dam. And in return, BC would provide the power that would have been provided by the higher dam, which was about 300 gigawatt hours a year.

And the BC government, I think, immediately downloaded the responsibility for implementing the Treaty to BC Hydro, both sides, the costs and the -- the benefits.

And under the agreement, there's a -- there are two financial payments. There's 35 annual payments of a fixed amount: $21.848 million from Seattle City Light to BC Hydro, and there's no indexation of that.

There are 80 annual payments of $100,000 that are indexed to inflation.

And that represents the avoided operating costs of this -- this High Ross Dam.

And the -- and in return, BC Hydro sends --

makes an annual delivery of power of about 300 gigawatt hours to Seattle, equivalent to what they would have got.

So the -- kind of the accounting challenge with that is that there's a mismatch between the deliveries and the payments.

So 80 years of deliveries, 35 years of -- of large payments, and 8 years of small payments. So when we receive the money from Seattle, we put it into an account. And we have set that account up so it will build a -- it, effectively, will match the power deliveries we're sending back.

So in 2013, we recognized from that account $14.8 million, so that was the revenue we deemed to recognize, and that would have gone in our revenue requirement application.

And the question was about the profitability of that. Our all-in average cost of energy, when you include the heritage generation and our IPPs, was -- in 2013 was about $38 for -- for generation. There's about $11 for transmission. So it works out to $49, which happens to come out to 15 million a year.

So we pretty much break even on the deliveries to Seattle. And I -- I would say that's

probably accidental because this thing was done years ago. And -- and will carry on for another -- going on another 50 years.

We don't have a forecast of our cost of energy and what this revenue will be in 2024. I -- I anticipate it will have gone against us at that point. And we'll be -- we'll be selling at -- we'll be incurring a net cost from -- from that transaction.

THE CHAIRMAN: So, in effect, for the next half century, we're going to wind up paying the Americans not to flood a valley of ours?

MR. CHRIS O'RILEY: Well, we're giving them power, and they're giving us money back.

THE CHAIRMAN: Sounds like a brilliant negotiation, whenever it occurred.

Okay. 19.

A deal is a deal, and I guess we've got to live with it.

MR. CHRIS O'RILEY: Yeah. And -- and, like I said, I -- I'm not sure. It was done at a time when -- if you go back to 1984, there was a bit of power around here, so you can see the -- the benefits of that arrangement. It was effectively a long-term sale of power, which at the time made

sense for the company and the Province, so ... At a -- at a fixed price, so ...

THE CHAIRMAN: It sounds like a Premier of Newfoundland I once knew.

Question 19.

MR. MIKE SAVIDANT: I can answer this, Mr. Chair. The figures in this -- sorry, the numbers that built this figure were from modelling studies. And the thing about these modelling studies is they require information on U.S. operations on the Kootenai and Pend Oreille Rivers. They both flow from the United States up into Canada, hit the Columbia, and then run back down.

The U.S. has an approach where they do their long-term data a decade at a time. So they do a lot of QC, we're told, that's -- that's one of the key reasons.

We just received the data for the last 2000 to 2010 late last year. We're currently using it; we're building the modelling studies right now, and we'll have that data probably later this year.

THE CHAIRMAN: I was sure there was a rationale reason for it, but that one is interesting.

MR. SAVIDANT: I don't know what it is.

THE CHAIRMAN: Yes. That covers the questions that the panel had for you.

Mr. Wallace, have you had any further representations?

MR. WALLACE: Mr. Chair, there have been quite a number of questions, which I have looked at and want to consider for a few moments. I wonder if we might take a break, and then deal with any that come up from that.

THE CHAIRMAN: Yes. We can certainly do that.

I wanted to ask, also, whether Hydro has any questions it wishes to propose to any other interested parties?

MR. PETER FELDBERG: At this point, Mr. Chairman, we haven't identified any.

THE CHAIRMAN: All right. We'll break for 15 minutes and come back.

(Brief break)

THE CHAIRMAN: Can we reconvene, please.

Mr. Wallace.

MR. BRIAN WALLACE: Thank you, Mr. Chairman.

The questions have been coming in during the

day. And there are -- a number of them dealt with demand-side management, elasticity of demand, GHG emissions and so on. All issues which I am satisfied have been thoroughly canvassed at the hearing.

There was a question relating to the accounting for sales of surplus power, but it's a matter which can be seen from the -- the annual report, and the annual report of BC Hydro was part of the record.

So I'm -- a large number of these questions I do not propose to put to BC Hydro.

There are a couple, though, of questions which I would like to put to BC Hydro's witnesses.

The first is a question relating to --

Sorry.

-- the use of gas to firm up non-firm energy in the context of BC's heritage -- BC Hydro's heritage resources as opposed to -- as opposed to the run-of-the-river project, which is the context in which we've been discussing it.

The questioning comes with a fairly long preamble, and it -- but the premise of it is that if you were to look at the gas alternative as a way to deal with high/low water years, and then

supplement it with surplus in high-water years, you'd end up with an average, which doesn't offend the 93 percent criterion, and would be a different way to look at firming up non-firm energy.

So I have two questions about that. The first is a general one, which is: Has Hydro looked at the use of gas that way in its appropriateness in the context of the 93 percent, and that question, I would like addressed this afternoon, the more detailed one because the material, which is on the screen was produced by Mr. Hendriks, and I -- it -- it is taken, he tells me, from material that's in the record. But it's been compiled and put together by him.

And so I think it's only fair to ask for any comments on the document itself to be produced by BC Hydro at a later date, perhaps Tuesday of next week.

So with that, if -- I would ask if BC Hydro could comment on looking at gas in this way as opposed to in the context of run-of-the-river.

MR. RANDY REIMANN: So we have, in the way we've modelled and accounted for the 93 percent factor or requirement, looked at average. And so there'd be years of more gas usage and years of less gas

usage, and what we're modelling and what we have proposed in the ERP and it's accepted as to look at that as average.

So I think the answer to your question is, yes, we -- we have. And other than that, I guess we'd like to take the document away and look and understand the context of it.

MR. BRIAN WALLACE: I think that we have to leave it at that. I can't really pursue it in more detail at this point because it is too detailed a question, and there's background material that says --

THE CHAIRMAN: I think it's a very good question, and, in effect, it was what I was trying to get at this morning, and I think I missed. Could you give us a note on that sometime early next week, Tuesday, Mr. Wallace suggests?

MR. BRIAN WALLACE: Let me just pull up the second question.

This question is --

THE CHAIRMAN: Just a second. Can we have a note on that --

MS. SUSAN YURKOVICH: Yes, we will.

THE CHAIRMAN: Okay. Thank you.

MR. BRAIN WALLACE: Thank you.

UNDERTAKING 93: With respect to a question relating to te use of gas to firm up non-firm energy in the context of BC's heritage resources as opposed to the run-of-the-river project, the questioning coming with a fairly long preamble, but the premise of it is that if you were to look at the gas alternative as a way to deal with high/low water years, and then supplement it with surplus in high-water years, you'd end up with an average, which doesn't offend the 93 percent criterion, and would be a different way to look at firming up non-firm energy.

Has Hydro looked at the use of gas that way in its appropriateness in the context of the 93 percent? The more detailed question to be answered by Tuesday, as the material produced by Mr. Hendriks, is taken from material that's in the record but it's been compiled and put together by him. BC Hydro to provide comments on the document itself.

MR. BRIAN WALLACE: This question relates to the water rental rates used in BC Hydro's analysis, it's represented at being, I understand, $5 per

megawatt hour, but the material seems to suggest it's actually 7 or 8 megawatt -- dollars per megawatt hour. And that -- and so I'm confused by what the rate amount -- amount is.

The financial suggests 5 to $8. The note this morning was that they were $5. And I'm not sure what the correct answer is and whether or not the -- it makes any difference.

MS. SUSAN YURKOVICH: We'll have Mr. Savidant respond to that question.

MR. MIKE SAVIDANT: So in the analysis that was undertaken in the IRP and the EIS, we were using Tier 3 water rental rates for Site C. Those are in fiscal -- in calendar 2013, those were $7.23.

All the analysis done in the IRP and EIS that was done prior to the November 26th announcement; after that, those water rental rates, after 2018, will go down to, roughly, $6.01. These all escalated in inflation. I believe the $5 I referenced was the difference between the Tier 2 water rental rates and the Tier 1 water rental rates.

MR. BRIAN WALLACE: Thank you.

THE CHAIRMAN: Thank you.

So Tier 1 and Tier 2 remain, and Tier 3 has

been cancelled as of?

MR. MIKE SAVIDANT: I believe the -- it's been announced that it's cancelled. It's cancelled as of, I think, 2018. So prior to the project coming into service.

THE CHAIRMAN: Okay. Thank you.

MR. BRIAN WALLACE: Mr. Chairman, those are all the questions that I have, that I am satisfied haven't been canvassed by the --

THE CHAIRMAN: There was one leftover question from Saulteau regarding eagles, which I suspect cannot be answered today, but, Christine, have you got the eagles thing?

MS. SUSAN YURKOVICH: Mr. Chair, if I might ask Mr. Hilton to come to the mic and answer that.

MR. SHAWN HILTON: Good afternoon. You may remember me from last week. I'm feeling better.

The issue of buffer distance and where we've used it here is in relation to, what we call, provincial best management practices or BMPs. There's a number of BMPs that the Provincial government has put forward, and -- and puts forward on their websites dealing with a variety of construction-related activities for a variety of different wildlife.

There are two that -- that would pertain to this. One is, what they call, develop with care. And it's available on the website for everybody to review and see for a variety of things. And it has buffer distance mentioned for a number of different species, for rural communities, urban communities, undeveloped areas.

There's another one called a rapture BMP, which offers additional recommendations for how you would go about doing work in a particular area.

It's designed for developers to review, as well as for practitioners like myself. Or other people to use as a source of information to help guide in activities.

In the case for the 500-metre buffer, it is a recommended buffer set forward by BMPs at certain times of year for -- for no clearing or no disturbance around nest sites, and that's where we've taken this number from.

THE CHAIRMAN: Was there another -- oh, what -- there's a second question there. Could you come and give that one a shot, too.

MR. SHAWN HILTON: Sure. So the first question is, if I look here.

"What procedures for bald eagle nest locations will be followed by BC Hydro?"

I -- I do have a written response for that in a book, and I -- and I may suggest that it might be something that we would follow up and give it very succinctly.

For -- for your benefit, the way we have outlined it is that we recognize that there's a number of bald eagle nests along the river. It needs to be censused again closer to the time of construction so that we get an understanding of where those nest sites are.

We've put forward in the mitigation measures that -- and around about a 2:1 ratio that nest sites would be replaced.

And the idea behind it is knowing that construction takes about nine years, by the time of clearing to be undertaken and the time for the reservoir to fill.

The expectation for us was if we remove the nest sites, and erect them in an area adjacent to the reservoir will be in the first year or so, they may not be used over that course of a period.

So, instead, was to create buffers around the existing nest sites, do our work in the area, hopefully maintain nest sites in the reservoir that would not be at risk of being flooded out during the construction of head ponds and so forth, but try to maintain some nesting in there.

And then at the end, when the reservoir was to be filled would be to try to look -- either you leave the nest structure where they are and they would be flooded, or in the case of removing them, but having the other structures in place.

The intent, as well, is to do the work at a time when the nests would not be used. So inactive.

Okay.

Ms. Melchior handed this. There are a number of mitigation measures, but Volume 2, Section 14, Table 14.16 on page 14-60 has some of these measures spelled out.

THE CHAIRMAN: Thank you very much.

MR. SHAWN BOLTON: Okay.

THE CHAIRMAN: Well, we are now at the end of the schedule.

Ms. Yurkovich, do you have any closing remarks for these hearings?

Closing remarks by BC Hydro:

MS. SUSAN YURKOVICH: Yes, Mr. Chair, if I might.

It's hard to believe that I'm going to wake up tomorrow morning and not come to this room and see you all.

In the last few weeks, we have heard from communities, from First Nations, from landowners, and individuals who have provided their thoughts and their concerns. They have identified the issues that are important to them. Some have also articulated their support.

And I would just like to thank all of the people who have come out to participate as part of these hearings. Many of them who have been here almost daily. And I -- and, in fact, some of these same folks have been part of actively diligence our consultation process over the last six years.

And I just -- I want to say that I recognize and I greatly respect the effort that they have undertaken, and the passion that they have brought to these proceedings.

I would, on behalf of our team, like to take a minute to thank the Secretariat. These have been long and logistically-challenging things to

schedule. And -- and to -- to operate and I -- and I -- I really -- I really want to acknowledge all the work that Courtney and Brian and the team have done.

And, also, to Nancy and her court reporting team who have taught us to speak slowly and to spell our last name.

And to the folks from the AV team who have helped put this panel hearing on.

And then, finally, to the panel, you've had an extraordinary amount of material to move through. It's been a huge task for you all. And I know that you have reviewed the large volumes very carefully. They are reflected in the detailed questions that you have asked of us.

And we have worked very hard to be as responsive as we can. We hope that we have provided you with the information that you require to undertake your deliberations.

And just on behalf of the BC Hydro team, we would like to thank you for your dedicated work here, and we want to wish you well in your deliberations.

Thank you, Mr. Chair. And thank you to Madam Beaudet and Mr. Mattison.

Closing remarks by the Chairman:

THE CHAIRMAN: Thank you.

Well, we are now at the end of a pretty intense five weeks of hearings. And I would also like to thank all of the participants for their patience and their good humour, mostly. And their hard work in educating this panel.

Even the weather seemed to cooperate. I can't believe that we haven't had complete upsets because of some blizzard or something.

I, too, would like to thank some of the folks who have helped us here. Alex Barbour over there in the corner running all of the audio-visual equipment.

Nancy Nielsen, her father, Kent, Steve Lee, Leanne Kowalyk, Diane Huggins, and Kerry Kinsella, the team doing these transcripts that you not -- you don't just get them tomorrow morning, you usually get them tonight.

Susan Yurkovich and, what we fondly refer to as the "Hydro Hoard," you folks have been open with information, have been hard-working and diligent at producing answers to sometimes outrageous questions, mostly from the panel.

You've been highly professional and hard-working.

I might say it's not easy being the target. And carrying the burdens of the history, you have the Bennett dam on your backs, and that's not the easiest thing to explain sometimes.

The First Nations, each of them individually. And Treaty 8 Tribal Association, who welcomed us into their communities, and provided some of the most penetrating questions about the project. Their professional work in this respect has been exemplary.

Many individuals from all around the Province, and those who spent their own personal time and treasure attending these hearings. And we appreciate that enormously.

The government departments, we sometimes forget the deep wells of expertise in our federal and provincial governments, and we are grateful for their unfiltered advice.

And the local governments, who have ably-represented their constituents' concerns.

So it's been quite a show. It is now up to us to write a report, which will go to governments on or about the 23rd of April.

The governments get to choose when to publish this, but they have promised to do so unredacted. And they will produce their final decisions within six months of getting the report.

So that's the process.

I'd now like to call on Tribal Chief Liz Logan for a closing prayer.

TRIBAL CHIEF LIZ LOGAN: Well, it's actually going to be George Desjarlais who does the closing prayer, so you guys can stand while you're listening to me, or you can sit.

THE CHAIRMAN: We need the exercise.

TRIBAL CHIEF LIZ LOGAN: All right.

Good afternoon, Mr. Chair, Madam Beaudet, and Mr. Mattison. This has been a long two months, yes. And I know that our involvement in this process is over, but your hard work is just beginning.

We ask that the Creator will give you wisdom, patience, confidence, and good health to complete the hard work that you have been tasked with. And we ask that the ancestors watch over you and guide you in your deliberations and recommendations to these two governments.

It is the Dane-Zaa way to welcome our guests

into our territory. And we did that in December. And it's also our custom to say farewell to our guests and send them on their way.

We'd sit with you, feed you, and tell you about who we are. And tell you about our culture and our traditions. Sometimes we'll hold a ceremony for our guests. But being inside of this building, we were restricted from burning a smudge, which is one of our ceremonies to bless us, to clear our minds, and to cleanse ourselves from any negativity before we embark on any business.

But we did have a prayer, as well as drum song by the Doig River drummers to help with the discussions that took place here.

It is our custom to share with our guests, and we feel that we've done that.

You sat with us. You've eaten with us. You've listened to us. And you've even danced with us. You've even beared witness to our ever-challenging relationship with this government, with industry, and, in this case, BC Hydro.

We hope that we've demonstrated to you during this time together how important our historic Treaty is and how we honour those rights and those promises that we agreed to between our ancestors

and the government of Canada.

The Elders tell us that this Treaty was an agreement to share, coexist, and to live in peace with the settlers. And we have done that. But we are currently being pushed off and out of our land, and we are now being told by our Elders that enough is enough, and to stand up and fight for it. And that's what we're doing.

The Elders have given us a mandate to protect the land and our rights, but at the same time, they have also mandated us to create economic certainty for our people.

I want to make this clear: we're not opposed to development. We just ask that there be a balance and development be done with as minimal impact as possible.

In the case of Site C, we're not opposed to meeting the energy -- the future energy needs of this Province. But this project and its impacts far outweigh any benefits.

We have been and still are willing to work with the Province and BC Hydro to solve this energy need in a balanced manner.

We hope that we've demonstrated how important our relationship to the land is, and we hope that

we are able to articulate to you who we are as people. We are connected to the land. We are of the land.

And that the rivers were our means of connecting with our families upstream and downstream, especially the Peace River, which is the largest river in this territory.

We hope that you've heard the reasons why we're so concerned about losing this valley.

Our people have a deep connection with this land because our ancestors told the stories and legends that are connected to that valley. And, most importantly, because our ancestral remains lay in that valley, and it is against our beliefs to disturb them in their final resting place.

A key point raised by many of the grandmothers is that water is life because water is spirit. And without spirit, we have no life.

The Elders would say when you take the water out of the body, you cannot call in the spiritual energies. Without water, our bodies are dead. Not only because of the dehydration that happens in the physical domain, but because of a lack of the spirit energy that signifies life.

The sacredness of water starts early in life

when the Elders told the children to never pee in the water. While we did not fully understand the significance then, things really came into focus once we began receiving teachings from the grandmothers. Simply, we don't pollute this water that we drink. We are taught that we must honour the water spirits. The rivers connect us as people, and that we may -- that we need water to survive.

We also use water in all of our ceremonies. We have many traditional teachings and laws and a lot of those teachings and ceremonies are related to water.

Some are as simple as giving thanks and leaving tobacco or food when you take water. Cleanse with water in our ceremonies like our sweat lodges. Only use what you need. Don't waste water. Don't throw a burning match in the water when crossing over the water, et cetera. There are many, many teachings and the meaning behind these and the reasoning behind these all differ between the Dane-Zaa people.

Women are called "carriers of water." And we're taught to respect the water. And honour the spirit of water before using it. That is one of

the fundamental principles underlying all traditional water teachings.

Women have always been the caretakers of water in traditional cultures because of their integral connections to Mother Earth. The earth gives life, food, medicine, clothing, and shelter. She gives life because we are, as women, we give life; we are connected to her in that way.

It's women again who are the caretakers of the water, therefore, several of us women would like to sing a song before George does the closing prayer to send you safely on your way.

We will be singing the women's warrior song. And if there are any women in the audience who would like to join us, please do so. And if you don't know the song, I still ask the women to please stand and join us.

And thank you, panel. And I wish you and your staff a safe journey tonight.

(Women's warrior song)

TRIBAL CHIEF LIZ LOGAN: George, if you could please come up and do the closing prayer for us.

George asks that, as is our tradition, that

all cameras and videos be turned off for his blessing song. It's a sacred sundance song, and to -- we ask that you please respect this wish.

MR. GEORGE DESJARLAIS: That includes this mic.

THE CHAIRMAN: Yes.

MR. GEORGE DESJARLAIS: The song I'm about to sing is usually the last song that is sung once the sundance is over. It's called the blessing song. And it's a prayer song. And the prayer that I had written was basically just given by Tribal Chief Logan. So all I'll do is sing this song to bless everyone that is here, to bless everything that has happened, everything that was talked about, so that everybody will go home in a good way, and, hopefully, arrive, the place that they have left a month and a half ago.

(Blessing song by George Desjarlais)

(The hearing closed at 3:23 p.m.)

REPORTER'S CERTIFICATION

I, Nancy Nielsen, RCR, RPR, CSR(A), Official Realtime Reporter in the Provinces of British Columbia and Alberta, Canada, do hereby certify:

That the proceedings were taken down by me in shorthand at the time and place herein set forth and thereafter transcribed, and the same is a true and correct and complete transcript of said proceedings to the best of my skill and ability.

IN WITNESS WHEREOF, I have hereunto subscribed my name this 24th day of January, 2014.

_____

Nancy Nielsen, RCR, RPR, CSR(A)

Official Realtime Reporter

B

C

D

E

G

H

I

J

K

L

M

N

O

P

Q

T

U

V

W