BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF THE UTILITIES COMMISSION ACT
R.S.B.C. 1996, CHAPTER 473

And
British Columbia Hydro and Power Authority -
F2020-F2021 Revenue Requirements Application

VANCOUVER, B.C.
March 15, 2019

WORKSHOP

BEFORE:

D.M. Morton,	**Chair**
A. Fung, Q.C.,	**Commissioner**
R.I. Mason,	**Commissioner**
E.B. Lockhart	**Commissioner**

VOLUME 1

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VANCOUVER, B.C.

March 15th, 2019

(PROCEEDINGS RESUMED AT 9:02 A.M.)

MR. JAMES: Good morning everybody. My name is Fred James, I am chief regulatory officer at BC Hydro. I want to welcome you this morning to our workshop on our fiscal 20 - fiscal 21 revenue requirements application. We have an agenda that is going to take us for about three hours, three and a half hours. So we should be finished around 12 or 12:30. We do have a break scheduled at around 10:15 or 10:30 depending on how the presentations go in the morning.

Our intent with this workshop is to provide you with a high level introduction to the application, and to guide you with your review of its contents. In a few moments, Chris O'Riley, our president and chief operating officer will be up here to provide some context into the application, and we also have David Wong, our chief financial officer. And also here to speak we have subject matter experts who will speak as noted on the agenda to those topics.

MR. WEAFER: Fred, sorry, I can't read that. Have you got a handout of that? Do you have a package for this morning's presentation?

MR. JAMES: We were planning on putting out the presentation as an electronic version after the presentation. The other slides that are coming are going to be much larger than this, so hopefully if -- they should be able to read the ones that are coming.

MR. WEAFER: Is there no possibility of having a hard copy?

MR. JAMES: We didn't bring any copies with us.

MR. WEAFER: Thank you.

MR. JAMES: Okay. So given the time that we do have today, and the fact that there is going to be lots of opportunity for questions to be answered through the IR process, we are going to limit our focus today to several areas that we considered would be of broadest interest to the audience. And similarly, while we will be doing our best to answer our questions that we get today, with information that we have at our finger tips, we may need to ask the detailed or more complex questions be deferred to the information request process.

We also may have to defer in the interest of time for this morning, issues that are of less widespread concern to the broad audience. Excuse me, I have a little bit of a cold here, so I am just getting over that.

I would ask that you hold your questions until the end of each of the sessions when the topics are being addressed, and that will give us some time then to go over your questions. We were hoping to keep this fairly informal, but because it is being broadcast, we do ask that you come up to the front of the room and speak your questions into the microphone so it is captured in the transcript.

Proceeding Time 9:04 a.m. T02

And as I mentioned to Chris, we will be posting the presentation on the Commission website and BC Hydro website at the end of the workshop this morning.

So with that, I'm going to invite up Chris O'Riley, our president and chief operating officer.

PRESENTATION BY MR. O'RILEY:

MR. O'RILEY: Thank you very much. So I want to start by acknowledging we're on the territory of the Musqueam, Squamish and Tsleil-Waututh First Nations. We have very deep and strong relationships with all three nations and we're mutually committed to a path of reconciliation with those nations.

I'll turn now to introducing our team today. We're blessed at BC Hydro with exceptional people and you'll get to see a small sample of those today, and we have a number at the table and then as we move through at the break, we'll move some more people up here.

So I'll start with Mr. David Wong, who is responsible for financial oversite of BC Hydro. He also leads our supply chain and technology groups.

Mr. Bill Clendinning who runs our energy planning group. He's responsible for the load forecast. He's also responsible for prioritizing investments, capital and maintenance investments.

Ms. Heather Matthews runs our generation system operations and she's responsible for planning how we operate our reservoirs and generating facilities including the integration of independent power producers and market resources.

Mr. Rohan Soulsby manages and administers our independent power producer contracts. He also, and his team, represent out commercial interests in more strategic files.

Mr. Steve Hobson oversee our demand-side management activities, including our energy efficiency and conservation, our capacity-focused initiatives and low carbon electrification.

Mr. Ryan Layton will also be speaking. He manages our finance team and he provides day-to-day support to our business and fulfills our external reporting requirements. Ms. Carolynn Ryan, our new chief human resources officer leads our human resources function supporting our business and our employees from recruitment through retirement.

And Mr. Ajay Kumar our director of line, asset and planning. So he oversees planning for our transmission and distribution assets including meters and telecommunications.

As we start this review of our revenue requirements application, I think it's important to first acknowledge the perspective of those customers who are least able to bear the costs of our proposed increases. It is possible to be dismissive of the modest rate increases that we are proposing. We can tell ourselves that it's only a few dollars a month and that most customers will be able to afford it. I want to emphasize that for some of our customers, and that includes some of our smallest customers and some of our largest customers, it can be a struggle to pay any amount more.

Proceeding Time 9:07 a.m. T03

So I want to talk for a moment about two groups in particular. First are low income residential customers, and second are large industrial customers.

So on February 1st I attended the meeting of our low income advisory council. Some of you will recall that the council came out of the 2015 rate design application. It was a suggestion or recommendation of the B.C. Old Age Pensioners'

Association, and it was supported by other parties, including BC Hydro. And the intent of the council was to help BC Hydro better understand the experience of our low income customers and find ways to better serve them. And the council meets quarterly, and I attend once a year.

The council has been very beneficial in my estimation. We've received some very strong feedback from the council on our customer crisis fund, on our conservation programs that are targeted towards low income customers, and with respect to the particular challenges faced by customers in non-integrated areas.

When I met with the council in February, I shared a story that came to me over Christmas, and one that prompted considerable discussion among the group. A customer from Nanaimo wrote to me on behalf of his neighbour. And his neighbour was a struggling senior who had been disconnected and out of power for six months as a result of non-payment. It turned out that she had lost her federal income supplement because she hadn’t filed her federal income taxes, and she couldn’t pay for her power, she couldn’t pay for her phone, both of them were disconnected. And she wasn’t able to advocate on her own behalf to resolve the situation, and there was no support in place to help her. So, after being alerted to it, we were able to restore her power, we got her on a payment plan, we were able to support her with a customer crisis fund grant, and we connected with social services on a longer term plan.

For me it was an example of how close some of our customers are to the edge of financial collapse, and how a customer, particularly an isolated senior, can be lost within the cracks of our system.

I carry this story with me along with other insights from our customer low income advisory council to remind me of the particular challenges and concerns of our low income customers as we make decisions. It is a very important perspective for us to hold.

I also want to make a few comments about our largest customers, many of whom also struggle to pay for the cost of power. In September I attended a meeting of our association of major power consumers, something I do once a year, in addition to meeting with individual customers. And there are three things I hear from these large customers. One is they operate in extremely competitive global markets. And in some cases, declining markets where the amount of sales actually go down each year. They sell at highly volatile commodity prices, and typically aren't able to pass on input cost increases. And of course there is no allowance for inflation.

Proceeding Time 9:11 a.m. T04

And third, they increasingly have to deal with a hostile environment in terms of trade bearers.

Any rate increase is a challenge for these customers and that is a concern for all of us and all of our ratepayers at BC Hydro because we have a relatively high weighting to the traditional resource sectors in this province relative to the broader B.C. economy. So we are extremely conscious of the impact of rising power rates on these customers, and we worked very closely with them to manage bill impacts or conservation offerings and our rate design.

So all of that is the background as to why affordability was such a theme of the government phase one review, and we worked hard to keep our rate increases as low as possible, and certainly below inflation. We are proposing, as you know, from the application, a net bill increase of 1.76 percent on April 1, 2019 and .72 percent on April 1 of 2020. We talk about net bill impact because we are proposing to bring down the deferral account rate rider from 5 percent to zero percent, so the 2019 increase is net of that.

I will remind you that the deferral account rate rider was fixed for the duration of our former ten year rate plan, so we think it's positive for ratepayers that the BCUC will be able to determine the rate rider going forward.

The key changes that came from the phase 1 review include the write-down of the rates, using deferral account, and a renewed role and enhanced role for the BCUC in overseeing BC Hydro, not just over our revenue requirements, but over energy supply contracts and capital projects. And the review also addressed the standing offer program and the expiring biomass contracts.

Our application includes our planned capital program, and I want to make two points about it. I believe it's important that we keep investing in our system as it continues to age so we continue to enjoy the benefits of a safe and reliable electricity system and avoid building up a future obligation to reinvest. And notwithstanding the capital reductions we've taken relative to our previous plan, we believe this is a prudent plan and one that is consistent with our stewardship responsibility for these important assets.

Finally, we received a lot of feedback from the Utility Commission and interveners about various aspects of our business and what we do, and I want to say we're absolutely open to that feedback and responsive. And you'll see that demonstrated when Mr.

Clendinning talks about our load forecast, for example. Notwithstanding that we remain on track with our load forecast from the 2016, May 2016, we've made a number of changes and continue to make changes based on the feedback from past proceedings.

I want to move now to the highest level view of our revenue requirements and talk about the make-up of the $5.29 billion of revenue requirements, which is the fiscal 2021 amount. One of the comments is a lot of these costs are actually fixed for the test period and they are fixed because of prior commitments and expenditures such as past capital investments, past energy purchase agreements that have been signed, and the results of that are now flowing through the revenue requirements.

Some of these expenditures were reviewed and approved by the B.C. Utilities Commission, for example, the John Hart redevelopment project and the two Waneta transactions. Many others, as we know were subject to direction and exemption from BCUC review.

Proceeding Time 9:15 a.m. T05

A significant portion, about a quarter of the revenue requirements is represented by transfers to government. And these are marked in blue, and they include the 712 million of net income which is fixed for the test period.

Operating expenses appropriately get a lot of attention in these processes, and we've been working especially hard on that aspect of our budget to keep operating costs down. We do that by reducing controllable costs, notwithstanding we have non-controllable cost pressures, as well as increased demands on BC Hydro to meet new requirements such as the North American Electric Reliability Council, Critical Infrastructure Protection Standards.

We've taken particular care with the operating cost aspect of our application to explain that entire budget. Taking the direction from the Commission, they want us to go beyond what is happening at the margin. And I am looking forward to feedback on this to see if we've hit the mark.

Cost of energy also gets a lot of attention. It's a large and growing category of expenditures, and we've taken a number of actions to reduce these costs as much as possible.

I also acknowledge that this is a particularly complex part of our business, and the Commission concluded our most recent revenue requirements application with a lot of questions about how it's managed. And we are committed through this proceeding to provide that clarity, and we'll be starting today. I was involved in the original

Heritage contract inquiry with the Commission back in 2003, and subsequent revenue requirement applications. So rebuilding that understanding and confidence is a particular objective of mine.

I want to acknowledge that the Commission has been unable to effectively oversee our revenue requirements these past eight years, as the government effectively controlled rates through reviews and directions. And this also meant that there was little input from intervenors in the regulatory process. And I believe as a result, there has been a loss of trust between BC Hydro and Commissioners, and the Commission and intervenors on the other side. And as a result of that, we have a significant challenge to rebuild that trust, and rebuild that confidence, as well as our collective capacity to move through these complex processes.

To look at this history more optimistically, we have been here before, as we have returned to regulation after a long period of rates being frozen in the 1990s and the early 2000s. This is about the 20th proceeding at the Commission that I have personally participated in at my career. I have also been involved in a few projects and initiatives that would have benefited from such a proceeding.

So, I personally appreciate how valuable an open and transparent regulatory process can be in terms of ensuring good decisions as well as broad public support and understanding and confidence in those decisions, creating social licence if you will.

So we are committed to doing everything we can to make this process successful, and that includes providing the Commission and intervenors with an open and transparent view into the utility and our application. It includes taking time to answer questions, always with the goal of hearing concerns and building understanding. And it includes taking feedback along the way through this process about what is working and not working, and being willing to adjust through that.

So, I will stop there, and at the end of each speaker we have some time to answer a few questions, and then we'll hand off to the next speaker.

I think we are asking folks to come to the microphone so people on the phone can hear.

MR. AUSTIN: David Austin, Clean Energy Association of B.C. I'm having trouble understanding what is happening to the deferral account rate rider. My recollection is that it was first came into being, it was a temporary measure that was to be used to clear the balances in the deferral accounts/regulatory accounts. And there is no point getting into the difference between the accounts.

As I understand this application now, the original DAR is being eliminated, and instead of it, or in place of it, there is a permanent general rate increase of 6.85 percent. So, it seems to me what has happened is DAR has now become permanently imbedded in BC Hydro's rates as opposed to having an expiration date, is that correct?

Proceeding Time 9:20 a.m. T06

MR. O'RILEY: Well, Mr. Wong and Mr. Layton will talk in more detail about the deferral account rate rider. What is happening is previously the deferral account rate rider was set at 5 percent. It's going to zero. That's our proposal, and the Commission will ultimately decide what the rate rider is for the go-forward period.

MR. AUSTIN: Okay, so Mr. Wong will be able to offer an explanation of when that DAR was supposed to end because the balances in the deferral account would have been eliminated versus now it not ending and continuing on *ad infinitum*.

MR. O'RILEY: Mr. Wong will address that.

MR. AUSTIN: Thank you.

MR. WEAFER: Mr. O'Riley, it's Chris Weafer, counsel for the Commercial Energy Consumers, and on the outset I want to compliment the utility on its application. There's a lot of work that's been put into it. We've only glossed it at this point. It's a significant document, so we won't have a lot of detailed questions today.

[*Electronic Voice Recording: Participant exiting*]

MR. WEAFER: Oh. I try to say something nice.

And I also want to acknowledge you, because we have great respect for your efforts to make change at BC Hydro and we know it's tough, and we have great respect for your efforts. So I just want to say those two things.

And the questions I have are policy level questions, I hope, and if they are not, send me away. But you talked about the government review of B.C. -- well, actually, let me preface it with this: You spoke about the residential customers and the large industrial customers and I just want to assure you that affordability is also of relevance to the commercial customers. The commercial class is seniors homes, hospitals, schools, small business. Affordability is very important to them as well. Would you agree?

MR. O'RILEY: Absolutely, Mr. Weafer.

MR. WEAFER: Thank you. We are in a -- there are two processes going on. We're involved in the capital review guidelines process and you're clear on this application, it's the material that was filed by Hydro which is to govern this application. Our evidence is not an issue in this proceeding, that's for a separate proceeding, correct?

MR. O'RILEY: Sorry, I'm not sure I understand your --

MR. WEAFER: The CEC has filed evidence in the capital review process which is before the Commission, but this application, essentially you've got the capital guidelines in play that you filed in that application. Is that correct? Is that your understanding?

MR. O'RILEY: What I would say is our application, this application and the elements of our capital program that are described are consistent with our proposal in that other proceeding.

MR. WEAFER: That's all I want to confirm. And that proposal was prepared and filed before the government review occurred, is that correct? Phase 1 of the government review occurred subsequent to you filing those guidelines, is that correct?

MR. O'RILEY: Yeah, I'm not sure of the timing, but I won't argue with you.

MR. WEAFER: I'm not trying to --

MR. O'RILEY: I'm not sure of the timeline.

MR. WEAFER: There's no trick questions here. I want to understand where we're at in terms of what's before the panel here. So -- Mr. James.

MR. JAMES: Sorry, Chris, I was just going to say, you know, we're here to review the application today. I think you're sort of getting into some legal argument or some legal discussion here around the evidence that's being looked at by the Commission. So if we could just sort of keep our questions focused on what's in the application today, that would be appreciated in the interest of the time we have.

MR. WEAFER: Of course, and that's what I'm trying to do is to understand the context of the application. And I think you agree that those guidelines are what are being considered in this procedure or used in this procedure. Those guidelines were filed before the government's review of BC Hydro. Subject to check.

Here's the thing. That review, as we understand it, has indicated that there's supposed to be enhanced regulatory oversight by the Commission. You'd agree with that?

MR. O'RILEY: That's a recommendation, and something that's come out of the government Phase 1 review.

MR. WEAFER: Thank you. And so turning to the government review, and again, just to understand the context of what occurred there, you spoke about the government review in your comments. Mr. James is standing so --

MR. JAMES: Once again, it almost sounds like we're getting into a hearing here and, you know, I think --

MR. O'RILEY: It's good practice, Fred.

MR. WEAFER: The objective, and I don't have a lot of questions today, this will probably be the bulk of it, and with complete respect, I'm not trying to sandbag you, I'm not trying to -- I'm trying to establish the policy environment that this application has been made.

Proceeding Time 9:25 a.m. T07

So I think that is fair in terms of an approach to questioning. Are you comfortable with the questions?

MR. O'RILEY: Please continue.

MR. WEAFER: Thank you. The nub of the issue is the government's review, and I'm looking, I haven’t read the application in detail, but appendix C in terms of -- which deals with the comprehensive review of BC Hydro, indicates that BC Hydro, page 2 of that document states,

"BC Hydro will reduce plant capital additions by 2.7 billion, from 18.5 billion to 15.8 billion, over the ten years from fiscal 2020 to fiscal 2029."

That's correct, right?

MR. O'RILEY: That is correct.

MR. WEAFER: Can you from a broad level give some indications as to what the government was able to do with the utility to find those capital efficiencies? What did they do that the regulator couldn’t do?

MR. O'RILEY: Well, I'll just speak in general to the capital plan. So that capital plan is BC Hydro's capital plan, and we update our capital plan every year, and Mr. Kumar will talk about in detail. And we do that based on our assessment of loads and growing loads, our assessment of the assets, and what -- really in the context of affordability for the corporation.

So there were changes made to both growth capital and sustaining capital over that time period, and some of the growth capital was we were able to defer because loads have not grown as fast. So it is not that things are permanently cancelled, but they've been moved out. And we took a really hard looking at the sustaining capital, and we were able to defer some of those investments, just based on our view of the health of the assets, and the various things we do to manage them. So, capital plan is a bit of an organic thing. It evolves over time, and it moves up and down as our assessments change.

So, what I want to say very clearly is that capital plan is BC Hydro's capital plan. It was put forward by our management and executive. It was accepted by the board. It's our capital plan, it's not the governments capital plan.

MR. WEAFER: Understood. And so in summary you found a more cost effective approach to capital by review of that plan. Is that a fair summary of how you arrived?

MR. O'RILEY: We made a series of tradeoffs. And the result of that was that capital plan.

MR. WEAFER: And you met all -- and I think you say it in your application that you met all your safety, reliability, community obligations in making those adjustments, is that fair?

MR. O'RILEY: Yeah, in particular we preserved the -- we have a number of important dam safety projects that are going forward, and we preserved those projects. We are not adjusting our risk profile in terms of public safety.

MR. WEAFER: Right, you did an analysis that the risks were not increased by finding those efficiencies in savings, is that correct?

MR. O'RILEY: Well I'm not sure that's true. I think the risks, there will be an increase in risks if we defer work. I think what we're saying is the broad risk profile of the company is within tolerable limits based on this plan.

MR. WEAFER: Thank you, Mr. O'Riley, I appreciate your time, and I didn't want to put you on the spot. Thank you, those are my questions.

MR. O'RILEY: Thank you, Mr. Weafer.

Okay, I will turn it over to Mr. David Wong, our chief financial officer.

PRESENTATION BY MR. WONG:

MR. WONG: Good morning everyone. Before I dive into my portion of the presentation, I thought I'd just ask you a question. And what do you think about when you think about BC Hydro? And hopefully you think about our 30 hydro generation units, and our 86,000 kilometres of transmission and distribution lines, allow us to serve 4 million customers across the province, across a vast and diverse terrain.

And it is important for us as we like to think about it, to do this reliably and safely. But as we talked about, we need to do it affordably as well. And so the application you have in front of you shows a rate increase request of 20 percent below inflation.

Today as Chris mentioned, we have subject matter experts from across our company who are going to go through the details of the revenue requirement, and provide some background to this application.

Proceeding Time 9:30 a.m. T08

And what we all hope is that at the end of this process that you will find that you have a good understanding and agree with BC Hydro's assessment of the cost required to run and deliver power to our 4 million customers.

So speaking to the comprehensive review which Chris talked about, I just want to highlight some of the details. This comprehensive review came out mid-February and was issued by the government and as Chris mentioned, it highlighted two key outcomes. One, the enhanced regulatory oversight of the BCUC of BC Hydro and second, affordability through a new five year rates plan. So I thought I would speak to two of those things -- those two things.

First, the BCUC enhanced oversight of BC Hydro, one of the key things that happened was the removal or repealing of several directions that restricted BCUC's decision making. And so now that those repeals, the BCUC is able to determine our rates, determine our regulatory, most of our regulatory accounts and how we're going to collect on those, and then starting in fiscal 2022, how we will determine net income. And so there's a transitory period over the next two years and the test period where net income for us is set at $712 million, but thereafter through the process with the BCUC, you will be determining our net income.

I think the other thing to think about is the integrated resource plan. So government is going to restore the BCUC's oversight over our integrated resource plan. This is the plan where we look at what the electricity demand will be over the next 20 years and how we're going to meet that. And that plan will be filed, hopefully, by February 2021.

Speaking to affordability, these are some of the key decisions that came out of the comprehensive review. As Chris talked to, one of the big decisions that happened was the write-off our rate smoothing regulatory account, over $1 billion that was in there. And I want to just remind you -- so what happened in the past is over the last several revenue requirements we had a few hundred million dollars of cost each year that we didn't charge the customers, so they weren't included in the rates. And in fact what we did then is we put those costs to a deferral account with a plan to collect that money in future from ratepayers.

So as part of this comprehensive review it was decided we won't be doing that anymore and this 1 billion cost will no longer be required to be included in the rates in the future.

Second, as Chris mentioned, we talked about the standing offering program, and suspending that.

And this is the high cost IPP energy that we were purchasing and were looking to purchase in the future. We will not be required to buy more IPP energy under this program, with the exception that we are looking at five contracts with the First Nations under the impact benefit agreements.

I think we had a lot of discussion about the capital investments and the reduction there. So we took a look at our ten-year plan of capital investments going forward in the future, and reduced it by 15 percent. And then finally, we're going to talk about and Ryan Layton will be coming up later along with Carolynn Ryan to talk about our operating cost. And we spent a lot of time, as we've done many many years, making sure we keep our operating cost below inflation. So it's obviously a big focus of us at BC Hydro.

Speaking to what approvals we are seeking, just to summarize this, we are looking for a general rate increase of 6.85 percent fiscal 2020 and a further .72 come fiscal 2021. We are, at the same time, asking to reduce the deferral account rate rider from 5 percent to zero percent effective April 1st and as a matter of all that together it comes to a net impact of a billable rate increase of 1.76 percent come April 1st, 2019 and another .72 April 2020.

I may be speaking to Mr. Austin's question related to the deferral account rate rider. One thing to note is that while the deferral account rate rider was originally planned to cover the deferral account, the energy deferral account build-up, so when costs were essentially higher than what we forecasted, we needed to get repaid for that through this rate rider.

For the ten-year rate plan, this rate rider, irrespective of what was in those deferral accounts, was planned to continue to move on indefinitely. So we now, through this process, have made a decision to reduce that to zero and look at just the pure rates. And of course the cost that we require to be recovered, and I'll talk about the rate drivers, incorporated in that 6.85 percent.

Proceeding Time 9:35 a.m. T09

On some of the other approvals, we are not asking for any new regulatory accounts. In fact we are looking to reduce it by two, and have a plan to reduce it further in the future as our path to reduce our regulatory accounts are something we're looking at. We will be requesting six changes, and Ryan Layton will be coming later on to talk about what those are.

Depreciation rates, this is more administrative, we have some new assets we need to confirm the depreciation rates against, like LED street lights and water rights. So that is in the application. And we have our open access transmission tariff which we require approval for.

Demand-side management expenses, Steve Hobson will come up later and talk about those. We need approval related to those programs. And then finally we ask for reconsideration of three directives that the BCUC previously made. Two are related to inconsistencies between regulations and directives that were previously done, so we want to get those aligned, and then the final one relates to reporting on a uniform system of accounts, and seeing whether there is still value related to having that report out or not, of whether the information we are providing in the form that we do today is sufficient.

Before we pass it on to the details, I thought it would be useful to go through the drivers of our billable rate increase, the 2.5 percent. You can see the red bars here are the cost pressures that we are facing, obviously offset by the green bars. So I thought if we can walk through this a little bit. If you start on the left-hand side, the first big red bar. This is essentially, because of the end of the rate smoothing deferral mechanism, and the costs each year in the past as I mentioned earlier, we weren't collecting those through rates. We now have to start collecting those. So that is the increase of the $321 million there. So those are the things that we need to do in rates now, because we need to start to collect on this money.

I want to confirm that anything that was occurred in the past, is not being collected. So this is only on a go-forward basis. So that is how you balance out the -- understand the rate smoothing account write-off that we did.

Following to the next two bars, finance charges and amortization. Of course as we invest in our capital program, when assets go into production or into service, we have the finance charges and the amortization associated with them, so we now need to include those into rates.

Something important to note is that in fiscal 19 we bought two-thirds of the Waneta Dam. That output has been sold to Teck, and you can see in the green bar there, under miscellaneous revenue, that is the revenue we get from Teck, and that helps offset those costs of the asset that we bought.

Going to the green side, the first green bar is our subsidiary net income, and that's a reduction in rates -- or an offset I should say. And that is where Powerex is making more income. When we do the five-year average, Powerex's average is going up, so we get the benefit of that. And we also get the benefit of the Powerex's net income being bigger than what it was when we forecasted it. And so because of that, we get to take that benefit and we give that back to ratepayers.

Finally, the last green bar is the cost of energy bar, offset by some returns we're going to give to ratepayers. So first, cost of energy on a pure basis is going up. And that really relates to more IPP costs, around $86 million, and Rohan Soulsby will talk about that. However, we've been able to offset those cost increases in this test period by the fact that we had some credit balances in our deferral account. And let me just explain that again.

So, this is the benefit of the deferral account. In the past few years we have been accumulating -- sorry, we forecasted a certain level of cost of energy. The actual cost of energy have been lower than that. So ratepayers get that benefit, and what we are actually -- what we're going to do now is give that back to ratepayers, and that is the offset to those increased costs and allows us to have that green line there.

And so the net revenue requirement increase of $210 million results in a 2.5 percent billable increase. The reason why, you've got to take the 210 and reduce it from the load increases. So the load increases as well and helps offset those costs. So that's a positive.

Proceeding Time 9:39 a.m. T10

When we take a look at it from an affordability perspective, as I mentioned, its twenty percent below inflation and 40 percent below our last ten-year rates plan, or old rates plan.

So we're going to go now into more details, but I guess I'll pause there and see if there's any questions.

MR. AUSTIN: Inadvertently I've got a great position to get to the mike today. That wasn't planned. I don't agree with your characterization of the deferral account rate ride but we'll leave that for another time. The question I have for you and all the other people on the panel, or your people that are here: What's BC Hydro doing to increase sales of electricity? You've got Clean BC as the government's policy in relation to reduction of greenhouse gasses in this province. I see barely a mention of it in here. But irrespective of that, you've got a high fixed cost structure and it would appear to the Clean Energy Association of BC members that what you have to do is go out and sell electricity and a lot more electricity. So where in this application does it set out how you're going to sell as much electricity as you possible can to push of revenues without pushing up costs?

MR. WONG: Okay, I think there's several things to think about. First of all, the next presentation, Bill Clendinning will talk about load. And so how we think about load and demand and how that translates into revenue, which is the specific point of the application in looking at the balance between what our costs are, essentially, and then how we manage that through the rates and the load.

From a perspective of demand for electricity, I think it's broader than just this application, and you're probably aware that the government is working with BC Hydro to do comprehensive review phase 2 and this is looking at the broader energy market and the impact of BC Hydro and how we fit in. The government issued its Clean BC report and talked about electrification, to be able to reduce greenhouse gasses and that increases, actually, electricity demand. And so a combination of all these things which will be taking place over the next year will help inform us as we go through this process in determining where the future of BC Hydro will be, and of course, addresses that demand question.

And like I said, I think it's probably best that Bill will then talk about more of the immediate terms related to load forecasting.

MR. WEIMER: I've just got to clarify something on your chart there. It's hard to read from here but the third green bar is 184 million?

MR. WONG: That's correct.

MR. WEIMER: But I think you mentioned that there were higher costs by 86 million. So does that mean you've pulled like 270 million from previous deferrals.

MR. WONG: Well, what we're saying is --

MR. WEIMER: That's a net number there?

MR. WONG: What we're saying is that the costs have been lower. We haven't been able to benefit from that, and that net balance is being -- it's given back to ratepayers.

MR. WEIMER: So in previous years your actual cost of energy has been lower by $270 million?

MR. WONG: I'd have to go back and reconfirm that exact number. I don't know.

MR. WEIMER: Than your forecast?

MR. WONG: But certainly we have the balances, and all of that is in the application. We can make sure we get the details right about that.

MR. WEIMER: It says that's a net number there, that 184.

MR. WONG: That's correct.
MR. WEIMER: Yeah, net of the increases, okay.
MR. WONG: Yes.
MR. WEIMER: Thanks.
MR. WONG: Okay, excellent. Well, thank you. I'll now introduce Bill Clendinning, our director of energy planning and he'll come up and talk about our load and load forecasting process. Thank you.
MR. JAMES: Before Bill gets started, I just wanted to -- picking up on Chris's comment earlier in the presentation, I didn't realize how far away the screen was going to be.
I didn't realize how far away the screen was going to be, and so we are having copies made of the presentation and we are going to be handing those out as soon as they are available.
PRESENTATION BY MR. CLENDINNING:
MR. CLENDINNING: Thank you, Fred. Good morning. My name is Bill Clendinning, I'm the director of energy planning and analytics. I'm here to present our October load forecast for the period out to F2024.
The key message I have for you today is that we've made changes to our load forecast methodology in response to recent Commission reviews, as well as internal audit from within BC Hydro. Our load is expected to grow but at a slower rate than was

previously forecast in May 2016. New growth is being led by upstream oil and gas operations with a potential for even more growth coming from emerging industries like cryptomining, cannabis and electric vehicles.

I've structured today's presentation in the following way. First I'll provide an overview of the improvements we've made to the load forecast and then step immediately to anchor the rest of the presentation in the forecast in total.

Proceeding Time 9:45 a.m. T11

I'll move down then into the individual customer sectors to give you an overview of those, and then I'll talk about the emerging loads that I just mentioned, and finish off with some of the uncertainties we see in the load forecast.

Enhancements made in advance of the October 2018 forecast were derived from three significant reviews of the load forecast itself. I've highlighted here examples of some of the changes that we've made in connection with those decisions, with further detail showing in chapter 3, section 2. After reviewing the Commission's decision on our F17 to F19 application, for example, we reviewed and then updated our estimates of how customers use of electricity is reduced in response to rate increases, also known as price elasticity, by moving them from negative 0.05 to negative 0.10. These changes were informed by a review we commissioned with independent experts.

We also examined other utilities' methods for forecasting electricity demand in the short term, and prepared an alternative forecast for comparison purposes with our own. And that was based on FortisBC's electric methodology applied to our context.

After reviewing the Commission's Site C inquiry final report, for example, we updated our LNG forecast approach, so it is now consistent with how we forecast all our large industrial customers.

In our most recent competitive procurement process, to select a provider of economic forecast, the Conference Board of Canada was the successful component. In addition to these two proceedings, BC Hydro's load forecast department was the subject of a BC Hydro internal audit. The internal audit team brought in a third party expert to assist with that review, and I'd like to, if I may, provide you with a quote from that report to summarize it.

> "Overall the load forecasting function at BC Hydro compares favorably to industry standards and to other large electric utilities in North America. No critical

weaknesses were found."

That said, the review did provide for 14 recommendations for improvement that we intend to implement. Two of which are included in the October load forecast, another eleven we are planning to include for the 20-year forecast we are preparing for mid of this year, with the remaining recommendations completed by the end of this calendar.

So let me move to the forecast in total. So as of October 2018, we're showing here that the recent actuals against our recent forecasts for comparison. The graph shows gigawatt hours on the left, and time along the bottom. The solid line represents recent actuals, and has tracked well against -- our May of 2016 forecast has tracked well against it. It is actually hard to see the May 2016 forecast because it is underneath the solid line. And to put that performance into quantitative terms, for F17 we were plus 0.1 percent within actuals. For F18, we were plus 0.5 percent within actuals. And I can tell you that as of the end of February year-to-date, we have been minus 0.6 percent within actuals.

The new forecast tracks along with the May 2016 forecast until about 2020, where we now show slower rate of growth in that period. The legend at the bottom shows the five-year compound growth rates, with the new forecast showing 0.5 percent per year for the period down from 2 percent per year expected in the previous forecast.

Changes in our expectations from May 2016 are shown on the right of the graph. The 2,350 gigawatt hour reduction in LNG shows our current view of these projects and reflects a delayed, but ultimately positive final investment decision by LNG Canada. While demand from oil and gas upstream operations underpins the higher expectations in the light and large industrial sectors, most other sectors see their forecasts out to 2023 cut relative to the May 2016 forecast.

So let's move down one level to the sector forecasts. The visualizations here have the same structure as the last slide, including the five-year compound annual growth rates at the bottom. I'll start with the industrial sector on the left.

As I mentioned, growth in the industrial sector is primarily led by expanding demand for electricity within the upstream oil and gas sector.

Proceeding Time 9:50 a.m. T12

While both the May 2016 and the October 2018 forecast expect a continued decline in pulp and paper, higher lumber prices are slowing the rate of decline in the current forecast. Although not smooth, the compound rate is 1.2 percent per year for F18 to F23, down from 4.4 percent expected back in 2016 for the same time frame.

The commercial and light industrial sector is anticipated to grow by 93 gigawatt hours over the next five years. This despite continued projections of economic growth in B.C. We are observing a weaker link between commercial economic growth and the use of electricity. That slower growth in electricity demand is now more than offset by efficiency improvements driven by efficiency codes and standards from various levels of government.

The residential sector is anticipated to increase, but at a slower pace relative to May 2016 as well. It is expected to grow by 400 gigawatt hours between fiscal '18 and '23.

To summarize, the commercial sector is expected to decline by .1 percent over the five-year period versus .9 forecasted previously and the residential sector is expected to grow by .4 percent down from 0.9 expected previously.

So I'll switch now to our emerging loads. In the area of emerging loads, there is the large potential for growth, but there's also large uncertainties associated with them.

Starting on the left, the first two graphs show the incremental forecast for cannabis and cryptocurrencies. This forecast includes projects that were either under construction or in the later stages of BC Hydro's interconnection process as of last fall. Note there is significantly more upside potential in these sectors based just on the sheer number of inquiries that BC Hydro has received. There is approximately 5,500 gigawatt hours of cannabis load at various stages of our interconnection process. There is approximately 650 gigawatt hours of cryptomining at various stages in our interconnection process as well.

Today we've had two cryptocurrency customers connect for about 25 gigawatt hours of expected annual load from our interconnection process, and we will see the first transmission level cryptocurrency customer for about 250 gigawatt hours connect this spring.

While there is considerable interest in these sectors, we took a conservative approach as we refined our forecasting methodologies for these emerging industries and the nascent nature of their operations.

Moving onto the third graph which represents total demand, our EV models are maturing and so we're showing non-incremental but total growth, and we can compare that against recent estimated actuals. So before I get the question, "What's an estimated actual", we don't have meters at the EV level and so we're able to gather information about the vehicle fleet within British Columbia and then project estimated use against those. So that's the closest thing like that we have to be able to do that.

And using that information, you can see the performance of our previous May 2016 forecast and our expected forecast moving forward.

So as I mentioned, for each of these forecasts, the range of potential growth is large. With the future of Canada some electric vehicles having a somewhat more certain future and less so on the cryptomining front.

Please.

COMMISSIONER FUNG: Mr. Clendinning, I do have a question about the emerging loads forecast. For two of them, at least, I think there's a certain degree of risk involved in terms of will this load actually materialize. Do you take that into account in your forecasts?

That's my first question. And then my second question is: What accounts for the flattening in the case of cannabis and cryptocurrencies after the initial growth?

MR. CLENDINNING: Thank you for the question. But I think those questions are connected. So the methodology that we've used here is to look at the queue and the latter part of the queue either connected or about to be connected customers. And so without a sophisticated model at this point around these, we've decided to be conservative, and so that queue ends at that point. And so we would see the evolution as we build our next 20 year forecast and refine our techniques to be able to put more of an uncertainty band around that.

COMMISSIONER FUNG: Thank you.

MR. CLENDINNING: Thank you.

THE CHAIRPERSON: Can you please help me understand what "incremental" means. As I understand it then, it means that in F19 there's going to be 100 new gigawatt hours and then in F2020 there's going to be -- what? Roughly another 250 new gigawatt hours. Is that what that means?

MR. CLENDINNING: Roughly, yes.

THE CHAIRPERSON: And is that net? Are you -- is there any accounting for possible load that would drop off?

MR. CLENDINNING: That's what's in the queue and we placed a high probability on folks who are at the end of the queue are about to connect, and it doesn't include lower probability customers further up. And I think to the first part of your question, there may be load of these types already embedded in connecting customers and that's why we've identified it as incremental as opposed to distinguishing them from the subsectors that they're in.

Proceeding Time 9:56 a.m. T13

THE CHAIRPERSON: But as I understand it – my understanding might not be correct – but cryptocurrency miners can be transient.

MR. CLENDINNING: Yes.

THE CHAIRPERSON: And so even if you connected a hundred, 50, 75 whatever it is in 2019, they may be only around for a year or two. So I'm just wondering if you've accounted for possible drop off in that scenario.

MR. CLENDINNING: Not directly, but what I'd say is given the magnitude of questions and folks further up in the queue, there may be an offsetting effect, but to be honest, we have not modelled with that in mind, to answer your question.

THE CHAIRPERSON: Thank you. I also have a question on the previous slide. I don't really want to interrupt your flow here, but if that's okay.

MR. CLENDINNING: Please.

THE CHAIRPERSON: And it refers to this slide and the one before it. If I’m looking at the -- it's the same question, actually. If I'm looking at the five year average, the grey dotted line, which has a date of May 2016, so that -- is that the date the load forecast was made?

MR. CLENDINNING: Correct.

THE CHAIRPERSON: Okay, so that's in fiscal 2017, is that correct?

MR. CLENDINNING: Yes.

THE CHAIRPERSON: Okay, so why does the gray dotted line start in roughly F2015? And if you look on the next slide, it seems to do the same thing. Even F2014 possibly. So why would a forecast made in F17 go back to possible F2014?

MR. CLENDINNING: I'm going to have to get you a more detailed answer to that question.

THE CHAIRPERSON: Thank you.

MR. CLENDINNING: I do know that we do use some techniques to be able to look at what the forecast looked previously, but that's obviously an oversight, thank you.

THE CHAIRPERSON: Forecasting the past can be quite effective.

MR. CLENDINNING: It's an easier gig.

COMMISSIONER FUNG: Much more accurate.

MR. QUAIL: So I have a question, if I may, perhaps at this point. Jim Quail representing MoveUP.

Have your forecasts taken any account of the probability of a recession during the timeframe that you're projecting?

MR. CLENDINNING: I think I'm going to ask you to submit that through an information request with the proviso that we do provide uncertainty bands that account for a variety of different economic impacts that are possible. And so the extent to which those economic factors could go in the same direction at the same time causing a recession, our Monte Carlo simulations can look at those, but I think that's a detailed question and I would want to answer more fulsomely through that process.

MR. QUAIL: Yes, I recall it actually -- about this time of year in the year 2008 being in this room and there was a projection of constant rate of growth at the current rate, and I actually posed a similar question and it was as though I'd landed from another planet suggesting that there was any disruption in the economy in the offerings. I'll follow-up your suggestion.

MR. CLENDINNING: Thank you.

MR. O'RILEY: I think you're in the wrong line of business.

MR. WEAFER: Good morning, Chris Weafer, Commercial Energy Customers. Just the two slides showing sort of levelling or going down on the commercial class. If we look at the emerging load forecast categories, I'm just trying to understand, the cannabis, cryptocurrency and electric vehicles, where you are seeing significant growth potential, to what extent would those fall into the commercial class?

MR. CLENDINNING: For the purposes of our forecast, it depends on how they connect to our service, whether it's transmission or distribution level. But oftentimes these emerging sectors don't fit into one of the different categories so it's up to us to be able to figure out where they -- as we evolve our forecasting technique, how do we transparently put them into the appropriate sector.

MR. WEAFER: All right. So that's more for an IR discussion in terms of the detail.

MR. CLENDINNING: We can definitely give you information on it.

MR. WEAFER: (OVERLAPPING VOICES) the commercial load, so where have you slotted these significant emerging categories will be a topic I suppose.

MR. CLENDINNING: We'd be happy to provide that information.

MR. WEAFER: Thank you very much.

MR. O'RILEY: If I could just add for context, we're talking here in gigawatt hours which are little less intuitive. I mean 300, 350 gigawatt hours is about 40 megawatts, so these are very much modest loads and modest forecasts, and in the context of our broader commercial sector, I would argue lost in that. So these are very much emerging, and you know, we'll see how they're going but we're not staking -- making big stakes on either of these industries.

MR. WEIMER: Could I just ask. Now, these three categories here I would think would be largely in the commercial or light industrial maybe. The electric vehicles might be a lot of residential. I'm seeing maybe 300, 350 and maybe a hundred, 750 altogether by 2021, fiscal '21. And if it's largely in commercial and light industrial, your total on the next chart doesn’t seem to have 750 in the light industrial. It seems to be flat or going down.

So, is something else declining quite a lot?

Proceeding Time 10:01 a.m. T14

MR. CLENDINNING: Yes, so these forecasts are inclusive of all the ups and downs for the various subsectors --

MR. WEIMER: So what we had on the previous chart, that 750 is actually -- that's what's in the load forecast?

MR. CLENDINNING: These ones here?

MR. WEIMER: Yes, that first step there. That is what you have -- so why do you call it growth potential?

You've actually put it in because they are quite far along in the queue, is that right?
MR. CLENDINNING: When I use the word potential in the slide, I am indicating that this is based on folks who are either connected, or about to connect in our system, and there is a large queue with a significant gigawatt hour total that could come in addition to that. That is speaking to the potential as opposed to here, the lines you see here are what we've included in the load forecast.
MR. WEIMER: This has been included. That's why it plateaus off there because all the ones that are further along in the queue or further back in the queue won't be included. So, from the looks of the incline there, that could go up quite a lot higher, but you don’t include it in the load forecast?
MR. CLENDINNING: That's correct.
MR. WEIMER: Yeah. Okay, thanks.
MR. WILLIS: CleanBC has some very ambitious EV goals. Do your EV forecasts line up with CleanBC?
MR. CLENDINNING: On the next slide, maybe I can move to that, we can talk a little bit about that. So there is considerable uncertainties in the load forecast. So what I'll do is perhaps walk through here and then talk about EV specifically at the end.
So, economic risk continues to be a key

uncertainty driver, particularly as it relates to future business and housing growth forecasts. While the USMCA or NAFTA 2.0 agreement has been reached, this has yet to be ratified. And there remains considerable downside risk in world trade. There are risks in pulp and paper and mining, that I think will be familiar to you. And despite extensive discussion predicting large and rapid increase and electrification last fall, including electric vehicles, in October we didn’t have anything as forecasters that we could put our foot against.

So we've included in this forecast only programs that were underway or near approval at that time. Now that said, we do have uncertainty bands that were included in the forecast, and by way of context I can say that our first view of the CleanBC plan and its initial portion represents about 4,000 gigawatt hours of incremental load potential.

There is robust growth in the upstream gas sector, and there may be the potential for even more, although primarily after the test period of the application. And I've laid out, and we discussed some of the potential cryptomining and cannabis uncertainties.

So, as far as EVs go, there has been some information released since the load forecast and we'll be looking to include the best information available, but the CleanBC plan is a phased approach, and we have limited information, and so we'll look what we can put our foot against, and assess it accordingly.

So, I'll just conclude before any further questions by saying we've made changes to our load forecast in response to recent Commission reviews and an internal audit. Our load is expected to grow, but at a slower rate than had been previously forecast, and new growth is being led by upstream oil and gas operations with the potential for significant growth coming from some of our emerging industries.

Thank you.

MR. AUSTIN: David Austin, I've got two questions, and perhaps the first one isn't one that should be directed specifically to you, but maybe you could direct it somebody else. Why is it going to take two years to come up with a new integrated resource plan?

MR. O'RILEY: We recognize that there is a lot of work to be done to develop an integrated resource plan, and it includes a new load forecast. So we're talking about the five-year load forecast that's been prepared. We are going to mid-next year have an updated 20-year load forecast. We've also got to review the planning criteria. I think that is part of the phase 2 review with government. So, for example there is a requirement to be self-sufficient in energy and that is up for debate, and that will be managed, that debate will occur in the phase 2 review, which is expected to happen this year. And there is -- once we have those elements in place, I mean there is quite a bit of debate about what the cost of new resources is. New wind projects and the like, and you know, some work needs to be done on that as well.

Proceeding Time 10:06 a.m. T15

So it is a long time but there are some things that will take up that time and we think are important to be done.

MR. AUSTIN: The reason I'm asking that question, and correct me if I'm wrong but in the *Clean Energy Act* there's been greenhouse gas reduction targets that have been there for about nine years. So the clean BC plan in terms of greenhouse gas reduction targets, and again, correct me if I'm wrong, hasn't really changed anything. And yet year after year when BC Hydro comes forward there's virtually no mention of what BC Hydro is doing in terms of meeting the greenhouse reduction targets that were set out about nine years ago.

And I'll go on just a little bit more at length here. I believe you said there was nothing that you could put your foot against in relation to the CleanBC plan and yet we've had those targets in the *Clean Energy Act* for nine years.

Why isn't there anything to put your foot against? It's been there for a long, long time.

MR. O'RILEY: Well, I would just say -- I mean it's a fact that the load forecast that Mr. Clendinning is presenting and was submitted in our application was prepared before the CleanBC plan came about. My understanding, there's not -- in the *Clean Energy Act* there are no targets on BC Hydro for reducing emissions, so I'm not a hundred percent sure what you're referring to there.

We're working with government on the elements on the CleanBC plan that relates to us. There's about 4,000 gigawatt hours of incremental load, from incremental to what's in our plan now – electric vehicles, transportation, upstream gas electrification. That's what we're working on with government and we're developing action plans and timelines around that.

Some of that will meet the threshold of what gets in a load forecast. And so when we come back in the mid-year, some of that will be in the load forecast, so we'll have a little more to put our foot against. Some will still be out there and will develop in further processes.

MR. AUSTIN: Year after year you're saying your costs are going up, we're paying more for IPP electricity, our system is aging. Yet year after year I don't see anything about what BC Hydro is doing to try to increase electricity sales without pushing up its costs. If you've got a surplus of electricity, if your costs are going up, where are your policies or your goals or your objectives for increasing electricity sales that would be consistent with the *Clean Energy Act* that was put in place about nine years ago?

MR. O'RILEY: Well, our goals are coming from the CleanBC plan, they're not coming from the *Clean Energy Act.* We're not responding to something -- there's nothing in the *Clean Energy Act* telling me to do that.

What I will say we're doing in terms of incremental revenues -- I think that's a very important question. Powerex is a big part of that, and it's both growth in sales of existing products and new products and value-added products by getting extra margin from clean attributes from our system and that is flowing back to ratepayers through the five-year average and the deferral account balances which are very positive from that. So that's one element.

We are and have been out consulting with ratepayer groups last year and through the fall on incremental rate options to grow revenues, so making permanent the freshet rate, and we intend to make that permanent. We're also looking for a long-term -- or sorry, a year-round equivalent of a freshet rate that would give existing customers at the margin access to market prices.

In addition, we've had a very active program to support electric vehicles and there's a lot of roadblocks to electric vehicle adoption in the province, and we're working to come at that. And we are very active with the upstream gas electrification.

Proceeding Time 10:11 a.m. T16

But all the companies that are making choices about whether to put in gas drives or electric drives are very active with them. So there is a lot of activity. The policy guidance for us is today the CleanBC plan, and that came out, as I said, after this application was essentially prepared. And we will develop more substantive plans with targets and milestones and the like to show how we're putting that plan in place.

MR. AUSTIN: But in terms of load forecast, where is it that you are showing that you are trying to take market share away from Fortis Gas?

MR. O'RILEY: Well, it's not in the load forecast. And I think it's fair that we've been criticized in the past for being, I'll say unduly optimistic about how changes in use of different commodities translates into load forecast. So, we're being very conservative about what gets in the base forecast, and you won't see that 4,000 gigawatt hours show up when Mr. Clendinning comes back in the summer. It will show up over time as our confidence grows about the delivery of those sales. So we are being very conservative over what shows up in the load forecast by design.

MS. DOMINGO: Good morning, Mr. Clendinning. My name is Yolanda Domingo with the BCUC Staff team. I have a couple of high level questions if you don’t mind answering and just help us maybe locate some information in your application.

The first one relates to weather normalization. And I didn’t read that in your chapter in your load forecast. And I'm just curious, your load forecast, has that been weather normalized?

MR. CLENDINNING: What I can do is after point you to the particular section where we talk about weather normalization and provide you with that.

MS. DOMINGO: Okay, and I guess that leads up to maybe a secondary question, and I'm just curious then, if it has been, and whether there is any consideration for this past winter. So this past winter we have been seeing some record temperatures, and not only that a record climate. So we had a low precipitation and also followed by a much colder winter than we've seen. And I'm just curious, does that have any impact in your first year's load forecast, and whether there is a need for an evidentiary update, do you think?

MR. CLENDINNING: So the forecast was prepared in October before some of the events that we witnessed this year, but that is part of the 20 year forecast. When we look at those type of phenomenon, we look at recent history in order to calibrate, and so I would expect that information to be included in the 20 year forecast, delivered mid-this calendar year.

MS. DOMINGO: Okay, so there won't be a need for an evidentiary update, is that what you're saying?

MR. O'RILEY: Yeah, we don’t typically update the load forecast for weather. There is always volatility around the weather, and we had a very cold February, we had a very mild January, a very mild December, so a lot of those things come out in the wash. And the load forecast is based on expected conditions. So long term averages.

MS. DOMINGO: Okay, a second question, and I don’t know if I missed it in reading the application. The application refers to an Auditor General report on BC Hydro's load forecast? And there was a quote indicating that the load forecast was robust. And there is no footnote to that quote, and my staff has been trying to find the Auditor General report whether that is a publicly available document, we're not sure?

MR. CLENDINNING: It is, and we can provide it.

MS. DOMINGO: That would be great.

MR. WONG: Actually, that Auditor General report, it relates to the asset planning for BC Hydro, and incorporates load forecasting into that. And it's included in the appendix to the application. So you should find it. I don't have the specific reference, but it is in the appendix.

MS. DOMINGO: Yes, that's perfect, thank you very much.

THE CHAIRPERSON: I have a follow up question to that conversation. When the 20-year load forecast is available mid this year, will you be providing that as an evidentiary update in this proceeding?

MR. O'RILEY: We'll be providing it. I think it remains to be seen whether there is an evidentiary update. I think there is a trigger for that.

THE CHAIRPERSON: Depends if it is different, yeah.

MR. O'RILEY: But we definitely will provide the 20-year load forecast when it is available.

THE CHAIRPERSON: Okay, when you say provide, you mean file it in this proceeding?

MR. O'RILEY: File, yeah, we typically would expect that to come through IRs, that's where that would be introduced.

THE CHAIRPERSON: Okay, thank you.
MR. CLENDINNING: Thank you.
MR. JAMES: So I note we're running a little late on time, so I think we'll have Heather and Rohan come up and speak to cost of energy. Could I just ask everyone to maybe hold your questions until the end of the session, the presentation topic sessions? And that may speed things along a little bit, thanks.
PRESENTATION BY MS. MATTHEWS:
MS. MATTHEWS: Good morning, I am going to talk about how we optimize our energy supply. And this was an area with a lot of interest in the last revenue requirements application.

So, we do this mainly through our energy studies process, and the energy studies serve three main purposes. One, it allows us to forecast our costs of energy that is in the revenue application and also for all of our financial reporting. It also allows us to forecast what the optimal operations are, and so that is both the generation of our facilities, what the reservoir levels are projected to be, and what the market transactions are going to be.

Proceeding Time 10:17 a.m. T17

And then third thing is that it helps us or allows us to set a basin price and this basin price is what we use when we're actually in operations and dispatching the system.

Now, there are three main drivers that affect the energy studies. The water inflow, the market prices and the load. Now, all of these drivers are based on forecasts and there is, also, of course, a lot of uncertainty in all three of these variables.

Now, regardless though, of what the forecast might be, customers actually only pay for the actual cost and we have regulatory accounts that are in place to manage the variance because all three of these factors can have large variance in any given year.

Now, our energy studies process has been indorsed by independent experts. So in 2019 we had an audit conducted by SINTEF. They are an organization in Norway, and their report can be found in appendix DD. What they concluded was that there are well-established processes that are in place. The key models are appropriate and the methodologies are in line with leading industry practices.

Now, the last thing to remember about the energy studies is that they are done to maximize the full value of the energy and it doesn't matter whether that energy is coming from Heritage assets or IPPs. In the energy studies it all gets combined and the overall objective is to just maximize the value of the whole system.

Now, one change that we have made in this application is that we've improved how we've been able to present the cost of energy, and we've been able to characterize it more clearly, mainly because the Heritage contract was repealed as part of the comprehensive review. So now there are three categories, there's the Heritage energy, the non-Heritage energy and the market energy. Now, the details of what is in each of these categories is in Section 4.6, .7 and .8. But how the energy actually is categorized doesn't actually affect -- like that's more of an accounting issue. It doesn't actual affect or come into how we operate the system.

So I'll take questions on this part of it and then I would pass it over to Rohan to talk about the other part of the cost of energy.

PRESENTATION BY MR. SOULSBY:

MR. SOULSBY: Good morning, everyone. My name is Rohan and I am here to provide a little bit of colour on the non-Heritage cost of energy component that you'll find details on in Chapter 4 of the application.

The slide in front of us shows how the large percentage, or the bulk of the cost of energy increases is due to increasing cost of independent power producers. The purpose of this slide is not to show how much more non-Heritage energy is than Heritage energy, rather it's to find a temporal view on how these different categories change over time. As I think is self-evident, the market energy component and Heritage energy components are fairly stable across the test years, whereas the non-Heritage energy which includes the IPP costs is increasing. And it's increasing by about $86 million during the period.

For context, the total cost and total value of our portfolio of independent power producer contracts is about $51 billion. So we talk about a $86 million increase, on a relative basis, it's not huge. Our annual costs for independent power producer energy are increasing from about 1.5 billion up to 1.6 -- just over 1.6 billion in fiscal '20-'21. As I said, that represents a change of $86 million, and you can see from this slide what the puts and takes are on that in aggregate.

The portfolio itself is a portfolio that consists of 130, approximately, independent power producer contracts. Each one of those contracts on a year-over-year basis has some increases, some decreases from our forecasting perspective in terms of what those costs would be. We're showing this in aggregate here.

Proceeding Time 10:22 a.m. T18

In terms of the cost reduction, what you'll see is there's some terminations of contracts. We manage the portfolio of course for the benefit of BC Hydro ratepayers. What we end up with, rights in our contracts that allow us to terminate, defer or downsize those contracts, we act on those rights. And during this period there was termination of three EPAs as compared to the previous RRA.

This RRA application also reflects the outcome of phase 1 of the comprehensive review. In particular, as David Wong mentioned, the indefinite suspension of the standing offer program, and the introduction of the Primas Energy Strategy.

From a standing offer program, what you're seeing in terms of impact during the test years is a reduction of about $5 million. That doesn't sound like a lot, and in fact the reason for that is because during those test years we had already forecast independent power -- or standing offer contracts to be in place at a rate of 150 gigawatt hours per year increasing year on year. So what this is showing is how that has affected, starting in fiscal '20, adjusted also for, as I think David mentioned, the commitment to enter into five standing offer program contracts that are related to areas where we have strong interests with First Nations or in fact through impact benefit agreements.

On the cost increases side, the vast majority of the increases are coming from existing EPAs. These are just the standard conditions of the contracts, either escalation factors, inflation factors, or other factors. However, there is at least one significant component that's added to increase that amounts to about $45 million, and that's the inclusion of the completion of Rio Tinto Alcan's tunnel 2 at Kemano. The inclusion of tunnel 2 in the forecast is providing additional energy to BC Hydro. It's also providing additional capacity, which is something that is going to be able to be used by BC Hydro in the north coast region in particular. So that's a significant component of those existing EPAs.

There were some new EPAs that were entered into through the standing offer program. I think there was four of them, and there was some renewals there. And somebody may ask, well, if you are renewing EPAs it costs much lower than the old EPA so why is it showing as a cost increase? The reason for that is that that's a blend of -- in fact, there was seven renewals in there, five of which are for biomass contracts, several which are before the Commission at the moment, and those contacts, as compared to the previous RRA where we had assumed only 50 percent renewal of the volume of biomass at a price of $50, are being included here at a higher rate as a result of the conference of new phase 1. So there's a slight increase in the total cost there.

So perhaps with that, I will stop and answer David's question.

MR. AUSTIN: At least you know my name. You threw out a figure of 51 billion as the value of your IPP contracts. Is that today's dollars or is that just -- if you want to call it gross dollars?

MR. SOULSBY: That's the simple costs. Some of the cost commitments in those contracts through the term of the contracts.

MR. AUSTIN: Right. So if it was discounted, would it be fair to say that you got half that value, discounted at today's dollars?

MR. SOULSBY: It would be a different number, yeah. I don't -- I'm not sure if it's half or a third or --

MR. AUSTIN: Well, you've already put that on the record before so I've got a pretty good idea what it is.

MR. O'RILEY: Customers will pay the full amount, so that's why we include the non-discounted value.

MR. AUSTIN: In relation to the previous graphs, if you could just go back on your slides. You're showing the red bars as your non-Heritage energy, and I have a couple of questions about that. In my mind there are two, for lack of a better word, "wild card" IPP contracts. The first is Alcan, and Alcan is on the books at 3300 gigawatt hours, and the next one is Island Generation or the gas-fired plant at Campbell River, and it's on the books at 2300 gigawatt hours. And we know from previous experience that the Island plant generates about 40 gigawatt hours of electricity annually. So for the purposes of the red bar there, are you showing or including in that red bar, Island generation at 2300 gigawatt hours or 40 gigawatt hours?

MR. SOULSBY: It's included in the forecast based on the expected usage, so it would be around 40 gigawatt hours. Keep in mind, David, that there are significant fixed costs associated with the contract.

MR. AUSTIN: I appreciate that. I just want to get an idea of its energy contribution. So its energy contribution is essentially 40 gigawatt hours?

Proceeding Time 10:28 a.m. T19

MR. SOULSBY: Based on whatever the forecast is of its expected use, yes.

MR. AUSTIN: Right, now for the purposes of Alcan, because the plant was modernized, Alcan took back a significant amount of electricity under the electricity purchase agreement with BC Hydro, and now you're saying because of the new tunnel, I'm assuming it will have less friction, I expect that it won't be able to pass through that much more water. But that is neither here nor there.

What number do you use for the purposes of the Rio Tinto Alcan contract? 3300 gigawatt hours? Or what number do you use?

MR. SOULSBY: Yeah, we use the number that is in the contract, adjusted in the near term forecast that are provided by the Rio Tinto Alcan during the operating timeframe.

MR. AUSTIN: Could you give me some idea of what that number is? Because clearly it is nowhere near 3300 gigawatt hours?

MR. SOULSBY: I would disagree with the characterization that it is nowhere near 3300 gigawatt hours, but I can't --

MR. O'RILEY: Yeah, I think that is a great question for an IR, Mr. Austin.

MR. AUSTIN: Thank you, Chris, I will be happy to write that one up. And should we send it to Rohan? Or somebody else?

MR. O'RILEY: They get submitted through the process.

MR. AUSTIN: I know, he can relax, it's okay, thank you.

COMMISSIONER FUNG: Sorry, I do have a question sir. On this chart, when it refers to non-Heritage energy and the increases in costs, what proportion of that energy comprise IPPs, the non-Heritage energy?
MR. SOULSBY: I don't have that number directly for you, but it is as I said, $86 million attributable directly to IPPs, and that number is -- it is a very small portion that is not IPP.
MR. WONG: The bulk of the red bar is IPP. I mean, I don't have the exact percentages, but it is a significant amount of it.
COMMISSIONER FUNG: Okay.
MR. WONG: I think some non-integrated might be some of the other pieces of that, but it, yeah, it is a significant portion.
COMMISSIONER FUNG: Okay, thank you.
MR. SOULSBY: Do you have a question, Fred?
MR. JAMES: Yes, do people want to take a break? So I think in the interest of time, we're running a little behind, but we will take a break for 15 minutes.
(PROCEEDINGS ADJOURNED AT 10:31 A.M.)
(PROCEEDINGS RESUMED AT 10:46 A.M.) **T20/21**
MR. JAMES: Sorry, just following through on our agenda, next up is Steve Hobson, our director of conservation and energy management to discuss the demand-side management expenditures requests that is

in our application.

PRESENTATION BY MR. HOBSON:

MR. HOBSON: Good morning everyone. I'll start off by saying the demand-side management plan in this application really builds off the plan that was outlined in the last revenue requirement application. And so you're going to hear me a few times today as I walk you through this refer back to how it is consistent with that application.

Starting point for that is it really continues with the moderation strategy that was outlined in that previous application, and continues to recognize BC Hydro's ongoing surplus.

Traditional demand-side management expenditures within this plan are at a similar level to what was outlined in the last application. Hydro is proposing to spend an average of about $100 million per year, in that range, across the two years within the test period. And within that we continue to offer a broad portfolio of offers across customer sectors, and have made a number of modifications within that funding envelope that I will speak to through this presentation.

The portfolio of demand-side measures is cost effective and offers a range of benefits that you can see on the slide in the boxes below. I'll focus a little bit in talking about cost effectiveness now though.

Continuing the approach from the last application, we've used the utility cost test against market prices as a cost effectiveness screen. At $27 the portfolio is cost effective against market prices valued at $30 per megawatt hour. And what this does is it indicates that we are in a position to lower revenue requirements, even in a period of prolonged surplus. Also note, that at $14, portfolios very cost effective using the total resource cost test, across a range of potential avoided cost streams.

Now, a lot of the cost tests and cost effectiveness information is very nuanced and unique to demand-side management. So we provided a fair bit of detail within chapter 10, specifically in section 10.5.4, if you're looking for more information on the cost tests and cost effectiveness.

And finally, on this slide, I'll just point out that in addition to the cost effectiveness views, there are a number of other benefits that are related to demand-side management and these expenditures, and they relate to such areas as GDP, employment impacts, greenhouse gas reductions and customer non-energy benefits.

So I mentioned earlier that we'd made some modifications to the plan relative to the last application. And these were really positive for us, they were drive off the feedback that we received through the process of the last application. We've also made a change that relates to a change in the demand-side measures regulation itself.

Most notably, we were asked to increase the expenditures in the residential sector, and we've responded by doing that. We've increased -- over the two-year period we've increased expenditures in that sector by 50 percent, and we've done it in two primary areas, or two program areas. So low income program, we've looked at the criteria and measures within that program, and we've also explored a number of new approaches for how we distribute our energy savings kits to increase participation. And then within our renovation rebate program, and that is a program designed to primarily improve the building envelope, and the heating systems with electrically heated customers, we've taken a look at some new measures and increased incentives in that program as well.

In the last application there was also a lot of interest in what BC Hydro was doing in non-integrated areas, and interest in us moving forward and doing something on a more permanent basis. So we've responded to that, we are launching a non-integrated areas program, builds off a lot of our pilot work that we have been conducting over the past few years, and responds to the feedback that we should have an ongoing program in that area.

I should mention that the three programs I've just outlined, as well as all of our programs, there is a lot of detail provided in appendix X within the application on each of those programs.

Proceeding Time 10:51 a.m. T22

Okay, and I mentioned demand-side measures regulation. One of the changes that we've made within this plan, within the demand-side measures regulation it defines energy management as a specified type or a specific type of activity, and we're required to break it out within our plan.

We were already doing a lot of energy management activities within our programs, and so what this exercise was about was really identifying those activities and costs, separating them out from our programs, and what you'll find in this application within each sector is an energy management initiative within each sector that actually isolates those costs.

So to avoid confusion with this, in Chapter 10, in table 10-16, we've provided a reconciliation table so you can walk through and see how we've made those changes.

Okay, and final modification I want to speak to, presentation of codes and standards was causing some confusion in our last application and so in particular we think the inclusion of codes and standards savings and some of our cost-effectiveness views was causing distortion and confusion. In this application we've changed our presentation of that. We've also moved forward with a report, which was a request in the last application. That's included as an appendix.

And in Chapter 10, in Section 10.2.3, there's a fair bit of discussion there in terms of how we've approached codes and standards this time around.

Okay. Low carbon electrification. In the last application we signalled that we were at the very early stages of exploring low carbon electrification. Since that time this area has evolved and I want to walk you through that a little bit, and we do so in the application as well.

So if you look at the picture and the arrow we'll start off with to the far left, we've identified a number of initial projects and these initial projects were to inform further plans or act on opportunities that would otherwise become missed opportunities in the marketplace.

As we're going through that process,

government moves forward with Efficiency BC and so as they move forward with some of their offers through Efficiency BC, they've asked BC Hydro to play a role in helping to administer those offers on their behalf. Need to really stress that those are government funded offers not ratepayer funded offers, so they are not part of this application but important for the story of what's happening in this area.

THE CHAIRPERSON: Does that include BC Hydro's cost to administer those programs too or --

MR. HOBSON: It does.

THE CHAIRPERSON: It does. Okay, thank you.

MR. HOBSON: Okay, and then finally at the far right of the arrow, BC Hydro has moved forward with, and developed a BC Hydro funded low carbon electrification program, and the intent of that is really to fill in the gaps that aren't targetted by government funded initiatives. So where we see opportunities to take advantage of a surplus environment and be proactive and productive with that surplus over a period of time, we are looking to move forward with our own program funds but only in areas where government is already not acting.

We are really expecting, and really the arrow leads to this big square, and it's been mentioned a few times today already, we expect this area to be quite fluid and future activity in this area is really going to be guided by CleanBC and as we get more details on CleanBC moving forward, we think this will change the landscape quite a bit.

Okay, we do have $28 million in low carbon electrification planned over the test period. The $28 million is outside of the traditional demand-side management expenditures that I would have alluded to up to this point in the presentation, and those fall under the greenhouse gas reduction regulation.

Expenditures are for the initial projects that I mentioned, as well as the low carbon electrification program funded by BC Hydro. The expenditures are prescribed undertakings under that greenhouse gas reduction regulation, and we have provided a fair bit of detail on this.

So in Chapter 10, as you go through that, it will talk a little bit about the story of how this area has evolved. In appendix Y we pick up on that story and we provide more detail about the prescribed undertakings themselves and how they fit within the regulation.

Okay? I think I'll pause at that point. I hope that provides you a bit of a general overview of how to navigate through some aspects of the material for the process, and I'm happy to take your questions.

MR. AUSTIN: David Austin. Does BC Hydro have any plans to bring forward an application to either eliminate the two-tiered rate for residential customers or modify it so that a residential customer who wants to invest in a heat pump, a heat pump hot water heater and/or an electric vehicle, won't be financially punished for doing so?

MR. JAMES: I can answer that, David. We are looking at potential rate design applications in the next year or two that will be addressing EV charging rates and also looking into potentially flattening the residential inclining block rate.

MR. ANDREWS: Bill Andrews. Steve, I have a question concerning the DSM envelope size, and I'm not looking for detail, but the two important numbers are the $30 per megawatt hour estimate of market avoided costs, and the $27 per megawatt hour utility cost. How comfortable are you in the $30 figure?

Proceeding Time 10:56 a.m. T23

Like is that at the centre of a very broad range? And likewise, I guess what I'm getting at is, is there room to increase the portfolio without exceeding a reasonable market avoided cost approach?

MR. HOBSON: I want to make sure I characterize your question properly. It is more in the interest of whether or not we would build the portfolio to a greater amount if that $30 was a larger value?

MR. ANDREWS: Yeah, I guess I am asking if $30 was just the mid-figure between 20 and 40, that might have implications for whether 27 is the appropriate way to evaluate whether the envelope is satisfactory.

MR. HOBSON: Understood.

MR. ANDREWS: But if that number is really firm, then it may affect the evaluation. What I'm getting at is at a high level, the size of the envelope and --

MR. HOBSON: Yeah, and to answer your question, there was a number of factors we looked at in the previous application when we approached this moderation strategy, we looked at a few different levels of demand-side management. And went through a process of looking at various attributes, including that $30 piece.

So, the impact on revenue requirements was a key principle behind how we looked at this, but there was a number of other factors that we took into account in terms of ability to ramp up rate impacts. There is a range of different things that were considered at that time. I don't know that if we were to say have a $35 value, I don't think we would go back and explore increase in the envelope just because of a variation from the $30 to that level. But I think if we saw something that really triggered a much more significant change in the value, then it would be something that we would go to revisit.

MR. ANDREWS: Okay, thank you very much.

MR. WEAFER: Chris Weafer, Commercial Energy Consumers. Steve, if you go back to slide 27, and you speak about the modifications to the DSM plan and residential expenditures have increased by 50 percent. Can you give us a high level description of what you've done with the commercial sector in terms of DSM?

MR. HOBSON: Yeah, commercial sector has decreased as part of a result of this, Chris, and it is on two fronts. So each year when we do an update of our DSM plan, we look at a variety of different things that have changed, or are changing in the marketplace, and one of them is we take a look forward in terms of what our projected projects are that are coming through. And we take a look at costs of different measures, a variety of different things. And so part of what we did see when we looked at that for the commercial sector was that we didn’t anticipate that we were going to go through the planned funds that we would have otherwise had for that sector based on our projection of what the projects were that were ahead of us. So, there was an opportunity to reduce the size that way and reallocate. And then the rest of it will be driven by managing to those budgets based on a shift in the allocation from commercial to residential for that portion.

MR. WEAFER: Yeah, no, thanks very much, we'll pursue it in IRs, thanks.

MR. WEIMER: Can you just go back to the slide that had the utility cost? Yeah, $27. So, do I understand this that utility cost is a net cost to BC Hydro? Net of any savings there might be from --

MR. HOBSON: I'm not sure I understand the question.

MR. WEIMER: Is the cost net of any savings from avoided generation?

MR. HOBSON: What this looks at, it's just, it's taking a look at the utility cost specific to the demand-side management. It would take a look at any of the capacity benefits that could be realized as a result of the reductions to the degree that those exist would be netted off, and then it is really a comparative value against the benchmark that could be $30 from market.

MR. WEIMER: Compared to market. What I was wondering was whether or not there is a reduction in there for the avoided cost of new generation. You mentioned capacity.

MR. HOBSON: Not on the energy side.

MR. WEIMER: Okay, not on the energy side, just the capacity.

MR. HOBSON: The only reason the capacity -- yeah, the only reason the capacity is included is because of the nature of the metric, and we can't have megawatts and megawatt hours together, and so those are monetized and put into the numerator. We do provide a table in the back of appendix X that details out all the components that go into the cost effectiveness test, if that's helpful to you.

Proceeding Time 11:01 a.m. T24

MR. WEIMER: Okay, is there a model included in the --

MR. HOBSON: There's not a model included but a series of results.

MR. WEIMER: But a print out of it? Okay, I guess it's a question for an IR then.

MR. HOBSON: I couldn't talk you through the model today.

MR. WEIMER: Okay, thanks.

MR. HOBSON: Okay, thank you.

PRESENTATION BY MR. LAYTON:

MR. LAYTON: Okay, good morning. My name is Ryan Layton and I'm the chief accounting officer at BC Hydro. And as you'll know, Chapter 5 of our application talks about operating costs. I'm going to highlight some key areas related to our operating costs, and my colleague, Carolynn Ryan, will talk a little bit out our employees and our compensation.

The chart here on slide 30 is Figure 5-1 from the application and it shows that BC Hydro has been able to limit base operating cost increases to an average of 1.2 percent per year during the test period. This is below the forecast rate of inflation of 2 percent and this marks the third consecutive revenue requirements application covering the last seven years in which our requested average base operating cost increases are below the forecast rate of inflation of 2 percent.

BC Hydro's base operating costs are subject to inflationary pressures and certain uncontrollable costs. In this application we showed that to achieve an average of 1.2 percent base operating cost increases we have partially offset non-controllable cost pressures with reductions to controllable costs which we'll discuss in the coming slides.

Here on slide 31 we show figure 5-5 from the application, which provides a visual breakdown of cost increases and savings areas for fiscal 2020. The first four bars in red on the left show the factors that are increasing costs. The green bars, conversely, show offsetting reductions resulting in a net change of $8.5 million represented by the grey bar at the end on the right.

Table 5-5 of the application provides

details on each item, and I'll summarize a few of the key areas. The figure shown on the slide shows that the increase in base operating costs is primarily driven by non-controllable factors. Two of these factors, storm restoration and the employer health tax, are non-discretionary and are beyond BC Hydro's control.

First, starting with storm restoration, we continue to budget for storm restoration costs using a five-year average of actual costs in normal weather years. It likely won't be a surprise to you then that this budget area is increasing as you've had significantly more storm damage and costs in recent years. And you can find in the application table 7-6 which shows the calculation and the increasing trend since fiscal 2014.

THE CHAIRPERSON: Excuse me.

MR. LAYTON: Yes?

THE CHAIRPERSON: I understand that the storm we had around Christmas time was possibly one of the historically worse, or more expensive storms that you've dealt with. So are those costs somehow reflected in this number or were they taken care of in last year's -- well, I guess the 2020 revenue requirements? Are the costs going to be ongoing? Can you just speak to that a bit, please?

MR. LAYTON: Yeah, absolutely. And you're right, Commissioner Morton, that the storm we experience in December was the most damaging in fact in our history. So I guess I'll talk about two things there.

Are the costs from that storm reflected in this revenue requirement? No, they are not. And the reason for that is because we use only completed fiscal years in calculating the five-year average, and so I referenced, I think it was table 7-6, which shows that we will use fiscal '14, '15, '16, '17 and '18, as those are completed years. So that drives the average.

In terms of the actual cost that we incurred this year in fiscal 2019, what happens with those costs is that we look -- at the end of the fiscal year when it finishes at the end of March, we take all of the costs we incur for storm, we compare it to the budget and the variance to plan goes into the storm restoration costs regulatory account.

Proceeding Time 11:06 a.m. T25

And so we will exceed that budget this year, largely as a result of that event, and those costs will be recovered from ratepayers in future test periods in accordance to how that regulatory account works.

THE CHAIRPERSON: Will all the costs associated with that storm them have been incurred by the end of

March?

MR. LAYTON: Yes.

THE CHAIRPERSON: The end of this March.

MR. LAYTON: Yes.

Okay, the second item I was going to mention on this slide is the second -- or rather the third red bar which is the employer health tax. This was introduced by government in their February 2018 budget and this increase is partially offset by the elimination of the previous regime of medical services plan or MSP premiums.

I'll also mention that the elimination of the MSP reduces our future costs related to our retirees and ratepayers get the benefit of this through a lower balance in the non-current pension costs regulatory account.

And lastly, in terms of the significant increases here in fiscal 2020, I'll note the salary bar there, and in terms of our collective agreements, the costs are tied to the bargaining mandate provided by the public sector employers council known as PSEC. With respect to our management and professional staff, the increases are essentially cost of living increases and thus are akin to non-controllable costs given how our compensation compares to medium market, and given that we've had very limited ability to increase these costs since 2012 under PSEC rules.

As shown by the green bars, various reductions have been identified across the organization to partially offset the identified cost increases.

Turning now to slide 32, this shows figure 5-10 from the application and it provides the results of the benchmark study conducted by Brattle Group. For your context, we note in the application that we undertook this study for this proceeding, and in response to BCUC's observation about the absence of evidence that BC Hydro uses benchmarking.

In Section 5.7 of the application, we talk about this benchmarking and other benchmarking that we use where it makes sense to do so, while recognizing the inherent limitations of benchmarking in many cases.

BC Hydro retained the Brattle Group to conduct an independent benchmarking study of our operating costs. We selected the Brattle Group to conduct this study because of their extensive experience with similar work. The study was led by their leader of the retail energy practice.

The report prepared by the Brattle Group shows that BC Hydro's operating costs benchmark favourably against a peer group of U.S. utilities in terms of both dollars per customer and dollars per megawatt hour.

As shown in the chart, BC Hydro is in the top, meaning the best, quartile for non-power production costs. These include transmission, distribution, administration and our relative performance appears to have improved in recent years.

COMMISSIONER FUNG: Sir, can I just interrupt?

MR. LAYTON: Yes.

COMMISSIONER FUNG: Why did your consultant compare BC Hydro to U.S. utilities as opposed to Canadian ones?

MR. LAYTON: Yeah, great question, Commissioner, and the reason for doing so is because in the U.S. under the FERC regime, all utilities governed by FERC in the United States have a consistent way of reporting their data, and therefore they were able to take that data and compare it to us.

In a moment I'll talk about exactly I think the reason you're asking your question, some additional work we did because we were interested in how do we compare against Canadian utilities. But for the purpose of Brattle did, they don't have that information available on a consistent basis, like the U.S. entities using the FERC regime, and that's the reason why

COMMISSIONER FUNG: Okay. I'll look forward to your explanation then. Thank you.

MR. LAYTON: Thank you. So, as I mentioned, the metric we're showing here on slide 32 is one of the several metrics used by the Brattle Group in the study, and the study concludes that BC Hydro's operating costs compare favourably to the peer group on an overall basis as well as at more granular levels and that this is true regardless of which metric is used.

Now, coming to the Commissioner's question, we move to slide 33, and in addition to the Brattle Group benchmarking study, which as I mentioned, leveraged publicly available and consistent data for U.S. utilities, BC Hydro prepared an indicative comparison to major Canadian electric utilities as we thought this would be of value, and indeed, it probably is.

Shown here on slide 33 is figure 5-13 of the application which shows that BC Hydro's operating cost compare favourably to these Canadian utilities. To prepare this analysis we reviewed published annual reports and rate applications of Manitoba Hydro, Hydro Quebec and FortisBC. Specifically we reviewed and assessed each entity's operating costs, number of customers and sales volume.

Proceeding Time 11:11 a.m. T26

We made assumptions in order to drive

consistency. We compared the results of the entities using the same metrics identified by the Brattle Group as being appropriate. Namely, dollars per customer, and dollars per megawatt hour.

We talk further in the application about the challenges in comparing these data sets, and hence when evaluating the results, we don’t look at any particular order ranking, but rather that we are in the same range of these utilities, which is what the table shows.

In addition to this work that we've done with the Brattle Group, benchmarking, and with our comparison to Canadian utilities, Chapter 5 contains further details throughout the chapter regarding how we've considered the BCUC's recommendations and comments relating to operating costs stemming from the Fiscal '17 to '19 RA application.

Section 5.2, including table 5-1, does this on a comment by comment basis, and provides information on where in Chapter 5 additional information is available. I will mention one area in particular. The Commission noted that given its limited involvement in recent RRAs, it wanted to better understand our base operating cost starting point, in addition to what drives increases in a given year. In response to this feedback, we've split

Chapter 5 into subchapters by business group. Chapters 5(a) through 5(h) and we have provided significant additional detail on operating costs and FTEs, including the composition, drivers, and outcomes of the overall budget of each key business unit in each business group. We believe this will help build understanding of the starting point, in addition to providing information on the cost drivers for the test period.

Now, before I turn it over to my colleague Carolynn Ryan, I will pause there for any questions? Okay, thank you.

PRESENTATION BY MS. RYAN:

MS. RYAN: Good morning, my name is Carolynn Ryan, I am the chief human resource officer at BC Hydro. As Ryan mentioned, we are committed to finding ways to keep our operating costs low, to ensure we can keep our rates affordable for our customers. And labour costs represent approximately 60 percent of our net operating costs, so we do take care in managing these costs.

The two primary drivers of labour costs are the number of employees we have, and the total rewards offered that we have to ensure that we can attract and retain the talent that we need. So first I'm going to focus on the number of employees, and then I'll talk about the total rewards offer.

By way of background, BC Hydro, we plan and budget for employee labour based on full time equivalent hours. So I will talk about FTEs through my presentation. FTEs are calculated by taking the total number of hours, so regular and overtime, worked in a given year and dividing that by the average number of hours that a full time employee would work in a year. So, those averages differ by affiliation and the information on how we calculate that is in the application.

Since our last application, we have shifted from contractors to permanent employees through our workforce optimization program, and we've transitioned services outsourced to Accenture back to BC Hydro. And while it has resulted in a number of permanent employees increasing from just under 6400 to just over 7400, it has generated significant savings.

The workforce optimization program has decreased BC Hydro's total costs by 18.5 million annually, and bringing the services outsourced to Accenture in-house has generated 8.2 million in annual savings. And you can see the savings on the righthand side in the blue bars. So I'm going to provide a summary of these two initiatives starting with workforce optimization.

Following the 2011 government review, BC Hydro reduced its employee population and eliminated unfilled positions. From F12 to F16 we managed our FTE count within an FTE maximum directed by government. And during this time, the labour requirement increased due to a 66 percent increase in our capital expenditures.

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So in order to complete this approved work without increasing our FTEs we contracted out the work. Using contractors is an important part of BC Hydro's labour mix, for example to deal with temporary spikes in work volume or to provide specialized skills that aren't required on an ongoing basis. However contracting out work is generally more expensive than having employees.

So as the capital plans were updated, it became apparent that we had ongoing capital work that would support increasing FTEs and reducing contractor usage, and doing so would reduce costs and provide BC Hydro more control and flexibility over the quality and service and the reliability outcomes of the work.

So in 2016 we raised our concerns with government about how the cost of resourcing the sustained growth in capital work with external contractors. And in response the government agreed to remove the FTE restriction and allow us to move to managing our labour costs under a total cost labour model.

After receiving this approval, we developed a principled based approach to decide whether to use employees or contractor for different work, and those principles are outlined in the application in Section 5.6. We call the whole thing the workforce optimization program. It's our approach to optimizing the mix of internal labour and external contractors. The approach considers factors such as whether the work is ongoing, the availability of workers, and the total short and long-term cost of each option.

So for example, if the work is of an ongoing nature, it involves high business risk and can be done at a lower cost internally, then we prefer to use an internal employee.

When there is a request to replace a contractor with an internal employee, we go through a process called the workforce adjustment process and it's submitted and that sort of business case is reviewed by finance, by properties, by HR as well as the executive team member.

So in our previous application, which we filed in July of 2016, we identified 170 additional FTEs that are shown on the first gray bar. And we noted that additional positions would continue to be converted, contractors to employees, in cases where cost-savings or improved outcomes could be achieve. The 170 FTEs forecast were based on confirmed conversions of contractors to internal FTEs at the time of the forecast, and they are included in the 6,365 on the left.

Since that time, the total number of employees added as a result of the program is 535, so that's the orange bar under the F20, to a total of 706 FTEs. As additional conversions were confirmed for the fiscal 2017 to fiscal 2019 period as well as the upcoming fiscal '20 to '21 period.

Table 5-9 in the application shows the workforce optimization program and the annual savings by key business unit on page 5-29. The total savings as a result of the workforce optimization program are that 18.5 million on the right.

We don't anticipate a significant number of new conversions through this program. We expect minimal, if any, requests for workforce adjustments will be approved going forward.

I'm going to move to the Accenture repatriation. In F03 BC Hydro outsourced a number of services, such as our call centre, to Accenture. Our agreement with Accenture was set to expire on April

30th, of 2018 and after considering the options whether to tender it to market, whether to renew the contract or to repatriate, we decided the best decision for us was to repatriate the services and do them in-house.

So the services returned to BC Hydro on May 1st of last year, resulting in an FTE increase of 423 you can see in the green bar.

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However performing these services in-house results in an annual savings of 8.2 million, which is on the right-hand side. In addition it provides us the ability to have more direct control over these important services such as our customer experience.

Approximately 80 percent of Accenture unionized employees accepted jobs at BC Hydro and table 5-11 in the application gives you a summary of the Accenture repatriation savings and the FTE impacts.

So the total number of 7,477 employees includes the 6,365 from the last RRA, including Site C, the additional 536 from the workforce optimization and the 423 from the Accenture repatriation.

Apart from growth due to capital investment, FTEs have been flat since fiscal 2012 and will remain flat. This graph shows FTEs by work function and does not include FTEs related to Site C or the Accenture repatriation. It's in the application in figure 5-8.

I does include all of the FTEs related to the workforce optimization program and it shows our FTE count has remained relatively stable since fiscal 2012, increasing by only 5 percent and most of this growth has been due to the increase in capital work and the conversion of contractors to employees, as I described, by the workforce optimization program.

The graph shows operating and deferred FTEs have declined, while capital FTEs have increased. Deferred FTEs refer to those FTEs whose work is charged to the regulatory account and almost all of them are to the DSM regulatory account.

THE CHAIRPERSON: Excuse me.

MS. RYAN: Yes.

THE CHAIRPERSON: So can I conclude from that that the conversion of contractors to full-time employees are, for the most part, in capital? Is that the right conclusion?

MS. RYAN: Yes. Yes, and we have a list of all of the KBUs where those worker optimization contractors have occurred in table 5-10, but yes, most of them are in operations.

THE CHAIRPERSON: Thank you.

MS. RYAN: So the number of FTEs will remain stable over the test period at approximately 6600 excluding Accenture and Site C or 7500 including those groups.

And to manage the number of employees we have and to ensure we remain within our labour budget we have a vacancy management process in place, which is essentially a series of approvals and business cases for filling existing or new positions.

In sum we take care in managing our labour costs. Since our last application we have saved money by converting contractors to employees where the business case makes sense and we've brought more expensive outsourced services in-house and we have a robust vacancy management process.

Apart from growth due to capital investment, our FTEs have remained relatively flat since 2012 and excluding the Site C project, FTEs will remain flat during the test period.

Now that I've reviewed the number of employees, I want to share a summary of our toward rewards offer which is the second driver of our labour budget. So we need to find a balance of providing an offer that's effective at attracting and retaining the employees we require while managing costs for our customers.

As a unionized public sector employer our offer needs to respect the collective agreements we have and align with policies set by government. We aim to provide a total rewards offer that is equivalent in value to the median rate paid in the market.

To assess how our total rewards offer compares to the market we contracted with Morneau Shepell to do a total rewards assessment in 2017 and their report showed that the value of our total rewards offer, which includes pension, benefits and time off, was in line with the market, being only 2 percent below the median rate.

However what is different is the mix of our offers. So similar to other public sector organizations we offer lower salaries and incentive pay but higher pension, benefits and time off.

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And this offer is proving effective. For example, programs like our pension plan help to retain employees, and our resignation rate is only 1.3 percent. This allows us to retain skilled workers like power line technicians to keep the lights on for our customers, and engineers to help build our capital projects like Site C, all while keeping total costs relatively equal to market rates.

Over the test period we are planning to increase union wages as Ryan mentioned earlier by two percent, which is in line with the bargaining mandate which has been set by PSEC for all public sector employers. The final increases will be negotiated with our unions as both of the agreements are up for renewal after March 31st, 2019.

With respect to our management and professional employees, we are planning for their salaries to increase by 2.5 percent per year. Salary increases for this group have been limited by a PSEC policy that has been in place since 2012, that either froze their salaries or limited individual increases to a maximum of 2 percent.

With these limitations, management and professional salaries have not kept pace with the market or union wage increases. A 2.5 percent increase is in line with forecasted market salary increases for 2019, so that our offer doesn't fall behind the market and increase our risk of losing key employees.

Overall, we feel we are prudently managing total costs, the total rewards offered, in a way that allows us to stay competitive in the market and to ensure we can attract and retain the talent we need.

Before I turn it over to Ajay, I'll pause for any questions? Thank you.

PRESENTATION BY MR. KUMAR:

MR. KUMAR: Good morning, my name is Ajay Kumar, I am the director of line asset planning.

So in addition to the operating costs that Ryan and Carolynn mentioned about BC Hydro also invests capital to sustain and grow its business. And in Chapter 6 of the revenue requirement application we have actually provided a lot of details on how we develop the composition of the capital plan, what the drivers are and how do we deliver that.

Overall, the capital expenditures for F20 and F21 are 2.9 billion and 3.1 billion respectively. The key message that I would like to leave for you with respect to our capital plan is, as Chris mentioned, it provides a prudent balance of affordability, performance and risk.

Before we get into the composition of the capital plan, I wanted to share with you a slide that shows the overall process that we follow for our capital planning. And this is what we call the enterprise capital planning process, and the details on this are provided in section 6.3 of our capital plan, of our revenue requirement application.

There are four key steps that we use in our enterprise capital planning process. Step one is the top-down planning, in which management and executives get together to discuss what the future capital plan for BC Hydro looks like. And as Chris mentioned, for this capital plan that we've developed, we looked at the softening of the load forecast and the system performance. As a result of looking at both those factors, we were able to reduce our capital plan by about $2.7 billion. And as David mentioned, that is about 15 percent of our overall capital plan that we had last year, which was a 10 year total of about $18.5 billion.

So, using those overall top-down discussions with our executives, we then allocate that overall capital to the different asset classes that we have in BC Hydro. And in step two you can see at the bottom there are six asset classes that we have, the generation, transmission and distribution, technology, properties, fleet, and corporate. Overall the generation and the transmission and distribution as a class are what we call the power system for BC Hydro and that accounts for about 90 percent of our overall capital expenditures.

And then when the different asset classes develop their capital plan, we bring it together in step three of our enterprise capital planning process, which is the collaborative review for consistency, where we bring all the different groups together, look at consistency across the capital plan, look at the risk profile across the different asset classes, and put forward an optimized capital plan that is then discussed in step four with our executives and with our board for endorsement. Which is then the foundation of what becomes the revenue requirement application.

So those are the four key steps we follow as part of our enterprise capital planning process. And that process has been in place for a number of years in BC Hydro.

Proceeding Time 11:30 a.m. T30

One of the things that I mentioned that we took into account when we looked at our overall capital plan was the system performance and what we've shown over here are two metrics that we use as part of our service plan with the government, and that reflects the system performance from a liability standpoint.

The top graph is what we call the duration of outages, which is measured in hours and it's defined as SAIDI. The bottom graph is what we defined as the frequency of outages on our system from a live energy perspective and it's defined as SAIFI. As you can see on both those metrics -- and we compare our performance against the CEA average, and there's about 39 utilities that take part in the CEA average on a yearly basis. And as you can see, in the top graph on a duration perspective BC Hydro had better performance that CEA average in all the years except in 2016 where we had the large storm in August.

And from a frequency perspective for all the last years going all the way back to 2009, you can see that our performance on the frequency of outages compared to the CEA average has been better. And that provided us with an indication of how we should be looking at performance and our capital planning for the future and was a key import that we used for developing the next ten years of capital plan.

Looking at the composition of our capital plan. Chris talked about the elements of growth and sustaining, and that's what we have shown over here in this graph. And this is a five year view, over the next five years how BC Hydro is going to be investing capital in the system.

The blue graph over here shows the sustained capital. And sustained capital is meant for addressing end of life issues that we are facing on our aging infrastructure, capital that we use for addressing safety, reliability, environmental and other concerns.

And the red bars show the growth capital, and that is the capital that BC Hydro invests in the system to expand the capacity of the system to accommodate the additional load growth that we see in the system.

And looking at the right-hand side of the graph which is the current capital plan, you can compare it against the composition of the plan on the left-hand side which is the previous capital plan that we had. And the key message that I would like to leave for you over here is that if you look at the right-hand side of our current capital plan, you'll see about 76 percent of our overall capital in the next five years is towards sustaining the system. And then we are 24 percent off our overall capital is towards the growth that we expect on the system.

And the other point worth noting over here is that you will see the totals that we have for the previous capital plan versus the current capital plan have lowered. And in the next five years, that reduction, if you add them up is about a billion dollars. And Chris talked about the $2.7 billion overall reduction. Of that 2.7, the first five years has brought a billion dollar reduction and then next five years is about $1.7 billion of reduction, giving you the total of that reduction that we talked about.

In terms of the test period, what this graph shows is the overall composition of our capital plan over the next two years. The right-hand side of the graph is with respect to our overall capital expenditures across those six asset classes that I talked about, and this reflects all the capital that we are to be spending on the system during those two years, which is F20 and '21.

The left-hand side of the graph shows the capital additions for those six categories and those are reflective of when the project goes into service, all the capital costs associated with that project is actually reflected in that year. So we have given both the views on terms of the capital additions as well as on the capital expenditure site.

And the key point over here is if you look at the overall composition from a Capex perspective, which is the right-hand side of the graph, you'll see about 90 percent of overall capital expenditures are with respect to transmission and distribution and generation which is the power system of our organization.

Lastly, I wanted to share with you some examples that have corroborated that BC Hydro has well-established capital planning and program delivery practices.

Proceeding Time 11:35 a.m. T31

The first one was -- and this is part of appendix F of our application, is a report that was undertaken or an audit that was undertaken by the office of the auditor general and that audit found that BC Hydro has strong management practices in place with respect to its capital, and there were actually no recommendations included in that audit report.

And I think there was a question from the commission staff in terms of the load forecast. Load forecast was one of the elements of that audit. There were 16 different elements that they looked at and appendix F actually provides that details on how we were evaluated against those 16 categories and in fact for the load forecast we had a mature rating from the auditor.

And the second report that I would like to highlight is that for a project delivery practices in 2016 BC Hydro received the Project Management Office award from the Project Management Institute and that is reflective of the project delivery practices that we have in BC Hydro in terms of delivering our capital projects.

Overall all, if you look at the last five years the projects that have been delivered by our project delivery KBU, they were 493 projects that were delivered and if you look at the actual cost of those projects versus the approved cost for those projects, BC Hydro was within .5 percent of those delivered projects over the last five year.

And that is again a testimony of our project management practices and methodologies that we have in place that allow us to deliver those projects on the expected cost that they were approved for.

So more information is available in Chapter 6 in terms of our planning methodologies that we used, the drivers behind our capital plan and how we deliver our capital plan and if there's any other questions I'm more than happy to answer those.

MR. WEAFER: Chris Weafer, Commercial Energy Consumers. Thank you for your presentation. I just want to confirm something I believe you said. The $2.7 billion in the savings in the capital plan, did I understand you to say that 1 billion of that was achieved in the test period of this application?

MR. KUMAR: Actually 1 billion was achieved over the next five years.

MR. WEAFER: Next five, okay. Thank you. I also understood you to say, in describing the enterprise capital planning process slide at page 38, that that's the process that's been in place for the most recent period of time at BC Hydro. That's been there for a few years?

MR. KUMAR: We have had this in place since 2017.

MR. WEAFER: Okay. So, between the last time this was done in the most recent period you found $2.7 billion in savings and a billion dollars within the next five years. Is that correct?

MR. KUMAR: That is correct.

MR. WEAFER: So what changed in terms of using that approach last year versus this year?

MR. KUMAR: There's a couple of things that led to this. The first one is I don't think it has anything to do with the process that we have followed. BC Hydro has had a capital planning process for a number of years. What this defines is an optimization of that process that allows us to bring the different groups together to present our capital plan.

The two things that led to that reduction of $2.7 billion that we talked about is, one is the moderation in load forecast, which is a fairly recent phenomena that we've seen in the province. So we were moving forward with some growth projects in the previous capital plans and as they found more about the indication of how the softening of that load forecast was happening in the province, that allowed us to have that discussion internally to see what the timing of those growth projects would look like and that is something that we reflected in this current plan as a result of the information that we are getting in terms of the future load forecast as well as the actual loads that we've seen in the province. So that was one factor.

The second is the sustaining capital. We were expecting to ramp up our sustaining capital over the next 10 years, but having looked at the performance of the system and as we get more intelligence from the asset conditions, and so forth, we had a lot of discussion in BC Hydro to look at how we should actually moderate that increase in the sustaining capital as we looked forward.

And having different tool kits at our disposal in terms of how we manage the reliability of the system, we were actually able reduce that sustained capital over the next year, few years, taking into account the system performance that we have seen, which is better than what we've seen in the other utilities, and they make the decision of reducing that into the future.

Track 32

Proceeding Time 11:40 a.m. T32

MR. WEAFER: So better and more current information enable you to find more efficiencies and cost effectiveness, is that fair?

MR. KUMAR: That is fair.

MR. WEAFER: Okay, thanks very much.

MR. WILLIS: Paul Willis. You've had smart meters in place for quite a while. Are you finding that smart meters help you with your capital planning?
MR. KUMAR: Absolutely. So this partly because we are starting to get data that is allowing the planning groups to make decisions based on actual data that we are getting from the meters, as well as from the field, which actually is an import into our capital planning process, absolutely.
MR. WILLIS: Thank you.
MR. LAYTON: Okay, hello again. Chapter 7 covers our regulatory accounts, and earlier in David Wong's presentation you heard about outcomes from the comprehensive review that have enhanced the BCUC's oversight when it comes to regulatory accounts. Here I'm going to highlight the approvals we're seeking in the application, as well as talking about our plans to manage the regulatory accounts going forward.
Here on slide 44 we summarize the approvals that we are seeking in respect of regulatory accounts in the application. Requests are fairly limited.
In the first bullet we are seeking approval to refund the forecast net credit balance in the cost of energy variance accounts over the test period. This would result in a net credit to benefit of ratepayers of $329.1 million being amortized into

rates during the test period. This aligns with our request noted earlier to set the deferral account rate rider at zero percent during the test period.

There are two pieces to the second bullet. First, we are seeking approval to defer any variances relating to the accounting for energy purchase agreements determined to be leases under IRFS 16 which are not already eligible for deferral treatment under existing orders to the non-Heritage deferral account. The reason for this request is that the standard is not yet in force for BC Hydro, and while we have included our estimates of the impacts in the application, these could change as we complete our assessment and work with our external auditors and/or based on any clarifications that may be issued by the international accounting standards board or others to assist as the implementation of the standard comes into force. This is further discussed in Section 8.13.3 of the application.

We are also -- the second part of the second bullet. We are also seeking approval to defer any variances between forecast and actual amounts related to the biomass energy program which are not eligible for deferral treatment under existing orders to the non-Heritage deferral account. The biomass energy program, as you heard earlier, is an outcome of the comprehensive review and is discussed in sections 4.3.2 and 7.7.1.3 of the application. This request will ensure that BC Hydro recovers its cost with respect to the biomass energy program.

The third bullet, we are seeking approval to continue to defer variances between forecast and actual dismantling costs to the dismantling cost regulatory account. The nature of dismantling costs make them difficult for forecast accurately and they've proven to be quite volatile, ranging from $14 million and 41 percent below plan, to $32 million and 89 percent above plan in the recent years.

Continued use of the account will mean the ratepayers only pay the actual costs of dismantling activities.

In the 4th bullet, we are seeking BCUC approval to defer low carbon electrification expenditures to the DSM regulatory account. Consistent with the direction to the BCUC respecting undertaking costs. You heard about our plans in respect to these from Mr. Hobson a little while earlier.

In the fifth bullet, we are seeking to remove the reference to the prescribed standards from the description of what may be deferred to the Site C regulatory account as BC Hydro now fully adopted IFRS.

In other words, our accounting standard has changed.

Proceeding Time 11:44 a.m. T33

This will allow BC Hydro to continue to defer to the account any cost related to the Site C project that are not eligible to be capitalized.

In the last bullet on this slide, we are seeking approval to close two accounts. The capital project investigation costs regulatory account at the end of Fiscal 2021, and the rate smoothing regulatory account in Fiscal 2020. The former is no longer in use, and its balance will have been fully amortized into rates at the end of the test period. And as you heard earlier, the rate smoothing regulatory account as a result of the comprehensive review, has been written off, and BC Hydro has ceased using the account.

THE CHAIRPERSON: I have a question please. Concerning the Site C regulatory account, and you are indicating that you will continue to make additions to the Site C regulatory account if a Site C related cost can't be capitalized under normal accounting treatment, is that correct?

MR. LAYTON: Correct.

THE CHAIRPERSON: So is that pursuant to a government directive? Or you would be asking for approval to add some -- our approval to add it to the Site C regulatory account?

MR. LAYTON: So it is not subject to any government direction or otherwise, and so we are seeking approval -- we sought approval in the last application essentially to do so, and we are seeking here to continue that treatment. The only change we are seeking is because our accounting standards have changed, and the order specifically references the prescribed standards, which are no longer relevant.

THE CHAIRPERSON: Thank you.

MR. LAYTON: Thank you. Okay, here on slide 45 then, we show figure 7-1 from the application which portrays the actual and forecast trajectory of our net regulatory account balance.

BC Hydro's total net regulatory balance peaked at $5.9 billion in Fiscal 2016, and is forecast to be reduced to $3.7 billion at the end of Fiscal 19, and to $3.2 billion at the end of fiscal 2024. This represents a forecast reduction of $2.7 billion, and almost 45 percent from the peak. A key driver of this reduction is the write-off of the balance and the rate smoothing regulatory account in Fiscal 2019.

Other factors contributing to the reduction include a one-time accounting adjustment of $319 million to the Heritage deferral account, as the result of an adoption -- of the adoption of a new IFRS revenue standard in Fiscal 2019, as well as the ongoing recovery of regulatory account balances and rates based on existing recovery mechanisms. And reductions to the trade income deferral account due to higher than planned Powerex net income. And you heard a little bit about that earlier today as well.

Over the test period, the balance of BC Hydro's regulatory accounts will continue to be reduced through the ongoing recovery of regulatory account balances and rates based on existing recovery mechanisms. The reduction is offset by the proposed refund of the forecast balance and the cost of energy variance accounts, and therefore as a result, there is only a slight overall change in the net regulatory account balance in Fiscal 2020 and Fiscal 2021.

BC Hydro has or has proposed regulatory mechanisms to recover the balances of all but three of our regulatory accounts and rates within the rate increases proposed for the test period, and within the rates forecast found in the comprehensive review.

The accounts for which we have proposed regulatory mechanisms represent 86 percent of the forecast of the Fiscal 2019 net regulatory account balance. The three exceptions are all accounts that don't yet need recovery mechanisms. The mining customer payment plan regulatory account, the Site C regulatory account, and the customer crisis fund regulatory account.

On to slide 46, we summarize table 7-2 from the application, specifically looking at the forecast Fiscal 2024 net regulatory account balance, and we show how it resides almost completely in five long term accounts. Indeed, approximately 98 percent of the forecast balance in Fiscal 2024 resides in five regulatory accounts that are being or will be recovered over a longer period of time, as the nature of these accounts are longer term. These accounts are first, the IFRS property plant and equipment regulatory account. This account arose when BC Hydro transitioned to IFRS accounting rules. The accounts being amortized over a 40 year period to approximate the same revenue requirement that would have occurred under the old accounting rules, and therefore ensured that ratepayers didn't incur an immediate, significant rate impact merely due to a change in accounting rules.

Proceeding Time 11:50 a.m. T34

The second account is the DSM regulatory account, for which the expenditures are added each year and recovered over the 15 year benefit period for customers.

Third, the Site C regulatory account, which has not yet been recovered in rates as the project is not yet in service. In a future application BC Hydro will propose that the balancing account be recovered over the average life of the Site C assets, once the project is in service, as that is the period that customers will benefit from the costs.

Fourth, the First Nations provisions regulatory account which draws down over time as annual settlement payments are made over a longer period of time.

And last the IRFS pension regulatory account, which like the IRFS property plant and equipment account is being amortized such that ratepayers are not subject to higher rates merely as a result of a change in accounting rules. In a case of this account, that's a 20 year amortization period.

So while a significant balance is still forecast at the end of fiscal 2024, the balance resides almost completely in accounts that are appropriately being recovered over a longer time period.

Here on slide 47, our last slide, we summarize some of the information found in table 7-9 of the application in which we note that the total number of regulatory accounts is declining and that up to eight existing regulatory accounts could be closed by fiscal 2024.

As you heard earlier, we are not seeking any new regulatory accounts in this application and are seeking to close the first two accounts shown on this table.

We will propose closure of the two Arrow water related accounts in fiscal 2022 and the Rock Bay remediation account is set to be closed in fiscal 2023. The timing of closing the remainder of accounts depends on a number of factors including, obviously, the Commission, but for example the mining customer payment plan regulatory account currently has no balance and it could be closed sooner if that continues.

The customer crises fund regulatory account may also be able to be closed sooner depending on whether it has a balance at the end of the pilot program, and over what period of time the BCUC approves the recovery or refund of that balance.

And I wanted to just clarify that that's not an indication that we don't see that customer crisis fund continuing in the future, that we don't support the pilot, we do. It merely reflects the fact that we viewed this account being related to the pilot and if that were to become a permanent fixture that it would be part of our normal costs.

So in addition to what I've covered in these slides, Chapter 7 includes further information on the approvals we're seeking, as well as historical information about each account, the recovery periods, and the charging of interest.

With that I'll be happy to answer your questions.

MR. AUSTIN: David Austin. Can you just go back one slide?

MR. LAYTON: Sure.

MR. AUSTIN: I'm looking at the numbers in the column and say for example, I've 976 million. Does that include the interest that BC Hydro's customers pay on that account up to 2024?

MR. LAYTON: Yes.

MR. AUSTIN: But it would not include the interest that they'll have to pay for the next 40 years, because I understand there's a 40 year amortization period on there?

MR. LAYTON: That's correct.

MR. AUSTIN: And similarly with respect to the Site C account, two questions. Is that account going to be amortized over 70 years?

MR. LAYTON: We expect so, yes. Sorry, I'll clarify, Mr. Austin, sorry. We expect to propose that. Obviously it's subject to the Commission.

MR. AUSTIN: And so the interest on that account from
2024 which is when Site C would -- at least the first
units come into service, would carry on for another
seven years?
MR. LAYTON: That's correct.
MR. AUSTIN: Thank you.
MR. LAYTON: The application of interest is to reflect
that monies have been spent and therefore there is
interest costs related to those expenditures.
THE CHAIRPERSON: While we're on this slide, can you
just summarize, which of these accounts there is no
amortization of in the test period, please.
MR. LAYTON: Yes. So the Site C obviously is one, and
as I mentioned, we won't propose to recover that until
it goes into service. The IRFS property plant and
equipment account has both additions and recoveries
during the test period Just kind of rolling into
rates. So that one has some.

Proceeding Time 11:35 a.m. T35

THE CHAIRPERSON: But the additions are only interest,
is that correct?
MR. LAYTON: No, they're -- until fiscal 2021 we're
still adding to that account as we bring that into our
operating costs over a 10 year period.
THE CHAIRPERSON: Okay. Yeah, okay. But Site C is the
only one for which there's no amortization at all?

MR. LAYTON: Correct.
THE CHAIRPERSON: Thank you.
MS. DOMINGO: Hi, it's Yolanda Domingo. You've mentioned a couple of times that there's the $1.1 billion write-off in the rate smoothing regulatory account AND then there's the one time 319 million credit balance to the Heritage deferral account -- Heritage or non-Heritage -- non-Heritage?
MR. LAYTON: The 319 million I mentioned relates to the net forecast balance of all three cost of energy variance accounts.
MS. DOMINGO: All three cost of energy, okay.
MR. LAYTON: So the non-Heritage, the Heritage and the trade income deferral account.
MS. DOMINGO: So I'm just curious, are there any other such one-time rate impact recognitions in any other deferral accounts or any other regular requirement buckets that you might want to speak to?
MR. LAYTON: I'm trying to think. There are 29 accounts, so bear with me while I gather my thoughts. In terms of one-time things. I don't think so. Most of them are occurring in the cost of energy variance accounts and obviously the rate smoothing account as you identified.
Off the top of my head I'd have to -- subject to check and thinking about it some more we

can canvas that during IRs. I can't think of others.
MS. DOMINGO: Sure. Sure, yeah we'll it in IRs. Thank you.
MR. WONG: And I don't believe so either, and just as a confirmation, the only -- the area where that may occur would be the IFRS adjustment related to leases. But that's because it's an accounting change. But other than that, no, We don't see any other one-time charges.
THE CHAIRPERSON: Just to clarify, either in the test period or beyond. Is that the question you're answering?
MR. WONG: Correct. That's correct.
THE CHAIRPERSON: Thank you.
MR. DAL MONTE: Hi Ryan, Carlo Dal Monte. Just one question. The one chart points to the employer health tax increasing.
MR. LAYTON: Yes.
MR. DAL MONTE: So in Ms. Ryan's presentation there was kind of the uncontrollable. Where does the benefit of the MSP reduction show up because that's -- right? That's post-retirement benefit. So where does that show up?
MR. LAYTON: Yeah, that's a great question. Two places. So in operating costs. When I showed the cost pressure before related to the employer health

tax, that's a net number.

Mr. DAL MONTE: Okay.

MR. LAYTON: So that's the employer health tax minus the benefit of the elimination of the medical services plan premiums.

The second place is the bigger number, which relates to our retirees. So we no longer will have to make MSP payments for our retirees. On a present value basis that's about just over a $250 million benefit.

And sorry, I'm going to answer Yolanda's question indirectly here, having now thought about it for a moment, thanks to your question. There is an adjustment there that's actually mostly already flowing through the account. That shows up in the non-current pension cost regulatory account.

MR. DAL MONTE: Okay.

MR. LAYTON: And through reductions in there and --

MR. DAL MONTE: So it would show up in a regulatory account?

MR. LAYTON: Yes.

MR. DAL MONTE: Thank you.

MR. LAYTON: To further my answer earlier to Yolanda's question, most of that has already cycled through so we won't see that in the test period but that is provided -- that benefit it provided to ratepayers and it is significant.

MR. McCANDLESS: It's Richard McCandless on the phone.

MR. LAYTON: Hello.

MR. McCANDLESS: Yeah I have a couple questions about the regulatory accounts. On your slide 44 you listed a number of bullets, but I read in the submission that in the non-Heritage you're wanting to basically continue to count any variance between what I'll call budget revenue and actual revenue and defer that in the non-Heritage. Is that correct?

MR. LAYTON: Correct.

MR. McCANDLESS: And my question, I guess, has to do with whether or not that is acceptable under public sector accounting standards and in my reading of what they went through in Ontario with the Fair Hydro and the auditor general of Ontario is basically being very clear that counting revenue in a regulatory asset is not acceptable. Have you checked that out with your new external auditor?

MR. LAYTON: So in response to your question, I think, the situation in Ontario is different in terms of the policy choices the Ontario government has made in respect of hydro in Ontario.

Proceeding Time 11:59 a.m. T36

In our case, currently we have one external auditor, that's KPMG. They've been auditor for a number of years. Obviously this practice of deferring those variances have been around for a while and has never resulted in any concerns in our externally audited financial statements. I can't speak to the view that the new auditor general will take when she becomes our auditor starting on April 1st. However, I will say that I'm not aware of any concerns so far in our work with them through the report that they have done and through conversations we've had with them related to that piece of our financial picture.

MR. McCANDLESS: Yeah, I suppose they wouldn't have concerns if they didn't exercise the option, but if you did, then they might have concerns.

One other point of clarification, and I just want to be clear about this. Would it be fair to categorize, and I'm just looking at the upcoming rate year, that the overall increase is around ten percent and the way I get there is by the rate increase of roughly 1-8, 1-7, the five percent surcharge being rolled into covering operating increases, and what I'll call a windfall accounting charge because of moving to IFRS, that you're going to give back to the ratepayers over two years. So that's roughly 3 percent in the upcoming year using 165 million. Is that fair?

MR. LAYTON: I have to think more about your math. I mean, at the end of the day, all of the items that you've mentioned are considered in our rate increase that we requested in this application, including the items that you mentioned, such as the one-time change due to accounting standard, as well as the refund. I think you refer to that as a windfall.

MR. McCANDLESS: No, I refer to the accounting standard as windfall.

MR. LAYTON: So that one time event is being refunded to customers in our proposal during the application so that will keep rates lower. I'm not sure, I think you're adding them to get to ten percent. We net all of the plus and minus off in coming to the rate increases that we ask for in the application.

MR. McCANDLESS: Yes, I understand, but in my simple world, that windfall wouldn't have normally been there, but you switched back to IFRS. So you're giving that back to the ratepayers. Normally that wouldn’t have been there.

MR. LAYTON: Correct.

MR. McCANDLESS: And then the surcharge of the 5 percent was there for a specific purpose and you are repurposing that now to cover ongoing costs plus the balance of what the ratepayer has to come up with. That's how I roughly get to my ten percent.

MR. WONG: Yes, I think what's important to look at, we do incorporate those items that you talk about into our rates plan, but we filed or presented our five year rates plan as well, and we are keeping rates low throughout that five year trajectory, 8.1 percent over a cumulative basis. So while there are some special items within the first two periods, we are able to maintain that throughout the five year plan.

MR. McCANDLESS: Well, in theory, but I have my doubts. The 1.6 percent under the old plan was probably not realistic, and the big difference here, of course, is getting rid of the rate smoothing which was really just allowing a lower rate increase than what was required and deferring it to future generations. But we went through all that in the past.

All I'm trying to do is simplify this down to the -- and the following -- part of the reason I raise this is that windfall, the two year windfall is going to end in the third year, so maybe that helps explain why – I know we're not talking about the third year – but what has to be charged to ratepayers jumps up again in the third year to help make up for the difference.

MR. WONG: Yeah, but I think you can look at the third year, which is in the application as well as the fourth and fifth and with the cumulative change it's still, you know, forty percent below what we had in previously in our ten-years rate plan, and as I mentioned earlier 20 percent below inflation. So we are maintaining the cost consciousness and control over that period.

MR. McCANDLESS: All right. Thank you very much.

MR. LAYTON: Thank you. Okay, I'm going to turn it back to Fred James.

MR. JAMES: Thanks, Ryan.

So first of all, thank you all for coming here today. First of all I want to thank our panel members and the excellent presentations they gave, but I also want to thank you members of the audience and the Commission panel for the questions that you also gave to us. It is very helpful for us in terms of getting ready for this regulatory proceeding.

Proceeding Time 12:04 a.m. T37

I just wanted to go over the regulatory schedule that the Commission set out in order G-45-19 which it issued on March 1st. The next stage in the process is going to be intervenor registration, which is by next Thursday, following the Commission IRs, which will be coming in to BC Hydro in about a month from now on April 23rd. About 10 days later, intervenor IRs are due on May the 2nd, and then BC Hydro will be responding to those information requests from both intervenors and the Commission on June the

6th. We will then get to see you all again on June 24th as we go into a procedural conference to determine the balance of the regulatory process for this application.

So, with that, unless there is any further questions from anybody on the process or -- I think we will close off today. And we are almost -- we are only four minutes over, so thank you very much for catching up on the time. Thank you.

(PROCEEDINGS ADJOURNED AT 12:05 P.M.)

I HEREBY CERTIFY THAT THE FORGOING
is a true and accurate transcript
of the proceedings herein, to the
best of my skill and ability.

A.B. Lanigan

A.B. Lanigan, Court Reporter

March 15th, 2019