## BRITISH COLUMBIA UTILITIES COMMISSION

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

**And**

**An Application by British Columbia Hydro and Power Authority for Review of the F2009 and F2010 Revenue Requirements Application**

**Vancouver, B.C.**
**October 21, 2008**

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# PROCEEDINGS AT HEARING

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**BEFORE:**

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| **L. A, O'Hara,** | **Chairperson** |
| **B. Milbourne,** | **Commissioner** |
| **A. Rhodes,** | **Commissioner** |

## VOLUME 13

**Allwest Reporting Ltd.**
2nd Floor-855 Homer Street
Vancouver, B.C

# APPEARANCES

| | |
|---|---|
| G.A. FULTON, Q.C. | Commission Counsel |
| J. CHRISTIAN<br>N. ELLEGOOD<br>I. WEBB<br>J. SOFIELD | British Columbia Hydro and Power Authority |
| D. CURTIS<br>S. HILL | British Columbia Transmission Corporation |
| M. GHIKAS<br>D. PERTTULA | Terasen Gas Inc (TGI), Terasen Gas (Vancouver Island) Inc. (TGVI), and Terasen Gs (Whistler) Inc. (Collectively Terasen Utilities) |
| D. AUSTIN | Independent Power Producers Association of British Columbia |
| P. COCHRANE<br>R. CARLE | City of New Westminster |
| R. B. WALLACE | Joint Industry Electricity Steering Committee (JIESC) |
| D. NEWLANDS | Elk Valley Coal Corporation |
| C. DAL MONTE | Catalyst Paper Corporation |
| C. WEAFER | Commercial Energy Consumers of British Columbia *et al* (CEC) |
| L. WORTH<br>J. QUAIL | B.C. Branch,B.C. Old Age Pensioners' Organization, Council Of Senior Citizens' Organizations, Federated Anti-Poverty Groups Of B.C., West End Seniors' Network (BCOAPO) |
| W. J. ANDREWS | B.C. Sustainable Energy Association, Sierra Club of Canada, British Columbia Chapter (BCSEA) |
| J. HUNTER<br>M. OULTON | Canadian Office and Professional Employees Union, Local 378 |
| A. WAIT | On His Own Behalf |
| S. MEADE | On His Own Behalf |

**CAARS**
**VANCOUVER, B.C.**
**October 21st, 2008**

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

THE CHAIRPERSON: Please be seated.

**B.C. HYDRO ENGINEERING, ABORIGINAL RELATIONS AND GENERATION - PANEL 6**
**DREW DUNLOP, Resumed:**
**LYLE VIERECK, Resumed:**
**CHRIS O'RILEY, Resumed:**
**MARK ELDRIDGE, Resumed:**
**RENATA KURSCHNER, Resumed:**

THE CHAIRPERSON: Good morning. Mr. Christian?

MR. CHRISTIAN: Good morning, Madam Chair. I have a half a dozen undertakings to file here at the outset of today's proceedings.

THE CHAIRPERSON: All right.

MR. CHRISTIAN: The first one is a response to a question from Mr. Weafer with respect to amounts that would go to the deferral account arising from storm expenditures. This was from transcript Volume 7, page 1212, lines 6 through 16. This would be Exhibit B-69.

THE HEARING OFFICER: B-69.

**(RESPONSE TO B.C. HYDRO UNDERTAKING NO. 41, RE. VOLUME 7, PAGE 1212, LINES 6 TO 16, MARKED AS EXHIBIT B-69)**

MR. CHRISTIAN: The next one arises from a request by Mr.

Fulton, and he asked about the average labour cost increases for IBEW employees in F2008, and the answer is in this undertaking, which is now Exhibit B-70.
THE HEARING OFFICER: B-70.
**(RESPONSE TO B.C. HYDRO UNDERTAKING NO. 45, RE. VOLUME 8, PAGE 1256, LINES 6 TO 22, MARKED AS EXHIBIT B-70)**
MR. CHRISTIAN: And the next one I have arises from a request from yourself, Madam Chair, at Volume 9 of the transcript. This was a request for a list of donations provided by B.C. Hydro in fiscal 2008. And the attachment here is a few pages long. It's Exhibit B-71.
THE HEARING OFFICER: B-71.
**(RESPONSE TO B.C. HYDRO UNDERTAKING NO. 55, RE. VOLUME 9, PAGE 1389, LINES 18 TO 26 TO PAGE 1390, LINES 1 TO 12, MARKED AS EXHIBIT B-71)**
MR. CHRISTIAN: The next undertaking response arises from a question from Mr. Fulton, or a request from Mr. Fulton, to file the on-line instructions with respect to expenditure authorization requests. And this will be Exhibit B-72.
THE HEARING OFFICER: B-72.
**(RESPONSE TO B.C. HYDRO UNDERTAKING NO. 64, RE. VOLUME 9, PAGE 1540, LINES 1 TO 26 TO PAGE 1541, LINES 1 AND 2, MARKED AS EXHIBIT B-72)**
**Proceeding Time 9:05 a.m. T2**

MR. CHRISTIAN: The next one is a request from Commissioner Rhodes asking for the costs of the property upon which the new facility in Chilliwack is located, and that's Exhibit B-73.

THE HEARING OFFICER: Marked Exhibit B-73.

**(RESPONSE TO B.C. HYDRO UNDERTAKING NO. 68, RE. VOLUME 10, PAGE 1627, LINES 2 TO 12, MARKED AS EXHIBIT B-73)**

MR. CHRISTIAN: And then lastly, for this morning at least, a question from Commissioner Milbourne for a breakdown of the ABSU administration costs, and this would be Exhibit B-74.

THE HEARING OFFICER: Marked Exhibit B-74.

**(RESPONSE TO B.C. HYDRO UNDERTAKING NO. 72, RE. VOLUME 10, PAGE 1658, LINES 3 TO 18, MARKED AS EXHIBIT B-74)**

MR. CHRISTIAN: And that concludes what I have this morning. Thank you.

THE CHAIRPERSON: All right, thank you, Mr. Christian.

Mr. Wallace, it looks like you have a filing there.

MR. WALLACE: Yes, I do also. On Sunday, October 19th, we became aware of certain issues regarding potential accounting standards changes with respect to fair value matters. We wrote to the Commission and circulated it to all the parties raising these issues, with the intent that these might be appropriately addressed by the update panel. I have spoken with Mr.

Christian. He advises that they have no objection to us placing questions of that nature to that panel. And accordingly I would ask that this be marked as the next exhibit for the JIESC, and we will deal with it in that manner. Thank you.

THE HEARING OFFICER: Marked Exhibit C5-17.

**(TWO-PAGE LETTER FROM R.B. WALLACE, BULL, HOUSSER & TUPPER, WITH EIGHT PAGES OF ATTACHMENTS, MARKED AS EXHIBIT C5-17)**

MR. WALLACE: Thank you.

THE CHAIRPERSON: Thank you very much, Mr. Wallace.

MR. WALLACE: And I'm not sure if the Commission has copies yet of the --

THE CHAIRPERSON: No, we don't.

After the morning filings, then we are back to Mr. Austin and continuing with our Panel 6. Good morning.

MR. AUSTIN: Good morning, Commissioners.

**CROSS-EXAMINATION BY MR. AUSTIN (Continued):**

MR. AUSTIN: Q: Good morning, panel. I'd just like to pick up where I left off yesterday. For anyone on the panel, can somebody tell me where mid-C is?

MS. KURSCHNER: A: Mid-C location on -- around the Columbia River on the border of Oregon and Washington, where a number of the original utilities have substations and historically that was the point where a lot of power was trading hands physically, and so it developed into what we now know as the mid-C mid-Columbia trading hub.

**Proceeding Time 9:08 a.m. T03**

MR. AUSTIN: Q: Is it west or east of the Cascade Mountain range?
MS. KURSCHNER: A: West.
MR. AUSTIN: Q: The answer is?
MR. O'RILEY: A: West.
MR. AUSTIN: Q: Ms. Kurschner, I'd like to refer you to Volume 12 of the transcript, page 2097. That's page 2097, lines 16 through 17. And in response to a question from Mr. Oulton, you said:

> "… Those are U.S. dollars at mid-C, and it is roughly $5 or so to bring it to B.C. border…"

And the $5 that you referred to, is that for firm transmission or non-firm transmission?
MS. KURSCHNER: A: I believe, subject to check, that it's 4-30 for the transmission and 1.9 percent for losses. I believe that would be non-firm transmission.
MR. AUSTIN: Q: That's non-firm. Have you any idea what the firm price would be, including losses?
MS. KURSCHNER: A: No.
MR. AUSTIN: Q: Could you undertake to check that?

MS. KURSCHNER: A: Yes.
MR. CHRISTIAN: We'll make the enquiry.

**Information Request**

MR. AUSTIN: Q: To anyone on the panel, how difficult would it be to book firm transmission from mid-C to the U.S./B.C. border for one year? And let's assume that the volume would be 4,000 gigawatt hours of energy.
MS. KURSCHNER: A: The volume would be 4,000 --
MR. AUSTIN: Q: 4,000 gigawatt hours of energy.
MS. KURSCHNER: A: Ah. In a month?
MR. O'RILEY: A: About fifty --
MR. AUSTIN: Q: Over a year.
MS. KURSCHNER: A: Over a year.
MR. AUSTIN: Q: Over a year, yeah.
MS. KURSCHNER: A: That's something that we would have to check on the current postings. I understand that a lot of that transmission is in fact already booked on a firm basis.
MR. AUSTIN: Q: So would you agree with me, it would be something that would be very difficult to do?
MS. KURSCHNER: A: I cannot agree without checking the postings.
MR. AUSTIN: Q: Oh, subject to check, and perhaps -- are you saying, would you like to look at this on an undertaking?

MS. KURSCHNER: A: Would I like?
MR. AUSTIN: Q: Well, I'm just trying to get a sense of how difficult or easy it is to do this, and not necessarily today, but over the -- say, for the last three or four years. It's my understanding that the transmission corridor which is called the I-5 corridor is very heavily congested, in particular south of Seattle.
MS. KURSCHNER: A: And that's a fair assessment, yes.
MR. AUSTIN: Q: Thank you. I'd like to refer you to Exhibit B-10. Page 16. Exhibit B-10, page 16. And that's Table 10.

**Proceeding Time 9:11 a.m. T4**

MR. O'RILEY: A: We've got it.
MR. AUSTIN: Q: And I'd like to draw your attention to the first entry in the table. It says "hydroelectric water rentals" and then there are a series of figures, plan update, et cetera. And would you agree with me that for the purposes of, say for example, the figure 2009 update, column 2, 48,274, and that's in gigawatt hours, that that is representative of the amount of energy that B.C. Hydro believes that it will be able to generate from its Heritage assets in F2009?
MS. KURSCHNER: A: The distinction I would make, you worded it as "believes it will be able". This is our expected generation from those resources, which is

quite different from our ability to generate from those resources and in different -- under different conditions, under different inflows and so on it might look quite different.

MR. AUSTIN: Q: That's certainly something I want to explore, but just in general terms, I'm just using this number of 48,274 as just a means of -- as a base for the cross-examination. Would you agree that that number 48,274 really consists of three main parts: energy that you might have inventoried from previous years, water inflows for the water year ending September the 30th, 2009, and the availability of the machinery and related equipment to generate that electricity?

MS. KURSCHNER: A: I think you had the wrong date on the water inflows, because if it's fiscal '09 it wouldn't be the inflows.

MR. AUSTIN: Q: But would you agree with me that for the purposes of inflow as B.C. Hydro uses the water year --

MS. KURSCHNER: A: It's storage inflows and it is predicated on our ability to get it out to the generating units.

MR. AUSTIN: Q: So you'd agree with me in the sense that those are the three main factors that go into this paper.

MR. O'RILEY: A: Yeah, it was just the previous water year, I think she's saying. So it was the year ending September '08. That would be the water year. You referred to September '09.
MR. AUSTIN: Q: My apologies. It's September of '08.
MR. O'RILEY: A: Yeah.
MS. KURSCHNER: A: Yeah, but those are the three key inputs.

**Proceeding Time 9:15 a.m. T05**

MR. AUSTIN: Q: Okay. Now, I don't plan to go through the inventory side of this figure because that was extensively canvassed by Mr. Weafer yesterday., but I would like to touch briefly on the water inflows. And on page 16, it says:

"Total system inflow for F2009 is now forecast to be 103 percent of normal."

Is that what it actually ended up as of September the $30^{th}$, 2008?
MS. KURSCHNER: A: Well, these numbers are fiscal year numbers, so this was our forecast at the time of the evidentiary date for the fiscal year '09. Our current -- that is the fiscal year that we're in, so it's still unfolding. Our current forecast is approximately 97 percent. So our -- we have had extremely dry summer and early fall, especially in the Peace region, so our inflows -- our inflow forecast

has been reducing month to month over that period.
MR. AUSTIN: Q: I promise not to go into the details of this, because it's my understanding that all that happens in a situation like this, the deferral account takes over, doesn't it, for purposes of accounting? If you're -- you previously estimated 103 and now it's down to 97, then all that happens is the deferral account changes. Is that correct?
MS. KURSCHNER: A: That is my understanding.
MR. AUSTIN: Q: Okay. Now, I just wanted to get a sense, for the purposes of F2010 in relation to the concept of water inflows. For the purposes of the update number, again I'm assuming that you have -- you may have an inventory factor, but for the purposes of water flows, am I correct in thinking that that number is essentially inflows at a hundred percent of normal?
MS. KURSCHNER: A: Generally when we do forecasts for the next year, we assume 100 percent inflow forecast, because we don't have any better knowledge. We don't know anything about the snow pack, so we assume the average, the normal, situation until we start gathering better information, which usually we don't have a better view until about January, February of each year.
MR. AUSTIN: Q: And even when you get to January and February of each year, you're never a hundred percent

certain until the end of September.
MS. KURSCHNER: A: Well, if we're looking at fiscal year, you're never certain until 30th of March.
MR. AUSTIN: Q: Okay. I'd like to refer you to Exhibit B-11. And I wouldn't close Exhibit B-10, hang on to that one, but I'd like to refer you to Exhibit B-11. And that's Commercial Energy Consumers Association of British Columbia, Information Request 1.2.5. Commercial Energy Consumers Association of British Columbia, Information Request 1.2.5.
MS. KURSCHNER: A: I have that.
MR. AUSTIN: Q: And in response to this, B.C. Hydro has provided the inflows as a percent of normal into B.C. Hydro's --
MS. KURSCHNER: A: Sorry, we have the wrong -- this talks about load curtailment. Is it (b)?
MR. O'RILEY: A: Are you saying 1.2.5, or 3?
MR. AUSTIN: Q: 1.2.5.
MR. CHRISTIAN: I think it's a different exhibit number. Exhibit B-5.
THE CHAIRPERSON: Yeah, that's -- I don't think that's right.
MR. AUSTIN: I've got B-11 on mine.
THE CHAIRPERSON: B-11 is --
MS. KURSCHNER: A: But is it the -- oh, that's a previous -- the IR you're referring, that's a

different hearing. The IR that you have. That's why. It's an exhibit in this hearing, but it's an IR from previous hearing. Okay, got it. I have that somewhere.

MR. AUSTIN: Q: Okay, so what exhibit number did that one fall under?

MS. KURSCHNER: A: I have it.

MR. AUSTIN: Q: Do you -- is it --

MS. KURSCHNER: A: It's Exhibit C6-6.

MR. AUSTIN: Q: C6-6. For once, I thought I had the right exhibit number, because it was posted in the exhibit itself. But -- so that's Exhibit C-6-6?

MS. KURSCHNER: A: It's C6-6.

MR. AUSTIN: Q: Okay, C6-6.

MS. KURSCHNER: A: That's what I have anyway.

**Proceeding Time 9:19 a.m. T6**

MR. AUSTIN: Do the Commissioners have that?

THE CHAIRPERSON: Yes.

MR. AUSTIN: Q: And in Exhibit C6-6 there is a table that shows the inflows into B.C. Hydro's reservoirs as a percentage of normal, and I was just wondering if you could complete that table by providing the inflows as a percent of normal for 2007 and 2008 fiscal.

MS. KURSCHNER: A: Fiscal 2007 is 89 percent. Fiscal 2008 is 109 percent.

THE CHAIRPERSON: Could you please repeat that 2007.

MS. KURSCHNER: A: 89 percent.
THE CHAIRPERSON: Thank you.
MR. AUSTIN: Q: Now, I'd like to refer you back to Exhibit B-10, Table 10.
MS. KURSCHNER: A: Yes.
MR. AUSTIN: Q: And just for the sake of understanding how much energy B.C. Hydro would be able to generate under lower water conditions, assume for the purposes of column number 5 that instead of the inflows being 100 percent of normal, that they are 85 percent of normal. What would be the reduction in energy that B.C. Hydro would be able to generate?
MS. KURSCHNER: A: So I can approximate. There are some head losses associated with it, but if you give--
MR. AUSTIN: Q: Approximation would be fine.
MS. KURSCHNER: A: Can you do 500 times 15?
MR. O'RILEY: A: 45. 7500?
MS. KURSCHNER: A: Yeah, and it might be a little bit more because we know there was an IR that said that one percent represented roughly 530 GWh. That, of course, is at a high elevation, so as you go lower it's less.
MR. AUSTIN: Q: Right, so if inflows were 85 percent of normal, the reduction in generation would be 7500 GWh, is that correct?
MS. KURSCHNER: A: Very very roughly.

MR. AUSTIN: Q: Roughly. Thank you. And just in rough terms, if the average spot market electricity price was $100 a megawatt hour for a year, and B.C. Hydro had to purchase 7500 GWh in the open market, approximately how much would that cost B.C. Hydro to purchase that electricity at $100 a megawatt hour?

MS. KURSCHNER: A: So you can of course look at it through that very simple math and multiply it, but it would not actually in reality work that way because that is the beauty of the reservoirs. If we have a below average inflow and the market prices are high, we would draw down the reservoirs instead of purchasing in the market.

MR. AUSTIN: Q: But assume that you did have to purchase, what would the cost at $100 a megawatt hour for 7500 GWh of electricity be?

MS. KURSCHNER: A: I guess I -- as I said, you can do the simple math. But even under a dry sequence, even under the worst conditions that we have had on the record, we never actually got into that situation. I mean, we're drawing -- well, actually, sorry, that's not true.

MR. AUSTIN: Q: That is true, because I believe in the year 2001 that you imported a significant amount of electricity, and the bill for the energy was approximately between 7 to 800 million dollars, is

that correct?
MS. KURSCHNER: A: I don't know that, but that was based on market.
MR. AUSTIN: Q: That's correct, but --
MS. KURSCHNER: A: So yes, you can do the simple math. And if you were forced, if you had no other option, then yes, it's a simple math and deficit times 100.
MR. AUSTIN: Q: And what's the answer? Pardon?
MS. KURSCHNER: A: What was the deficit, 85 --
MR. O'RILEY: A: Well, it's 750. The 100 multiplied by 750 gigawatt hours is 750 --
MS. KURSCHNER: A: No, 7,500 gigawatt hours, right?
MR. O'RILEY: A: Yeah, 7,500.
MR. AUSTIN: Q: Right.
MS. KURSCHNER: A: Times 100, so.
MR. AUSTIN: Q: So that would be, using the rough math with all your qualifications, that would be a bill of $750 million.
MS. KURSCHNER: A: Million.

**Proceeding Time 9:23 a.m. T07**

MR. AUSTIN: Q: Thank you. Now, I'd like to turn to the concept of the availability of machinery to generate electricity, and I'd like to refer the panel to Exhibit B-1, page 1-5. So that's the original application, Exhibit B-1, page 1-5. And this is starting at line 6. It says:

"Aging infrastructure, if not adequately maintained or replaced when conditions warrant, can have a profound effect on the safety and reliability of the electricity system. Many of B.C. Hydro's assets are old. Most of the large generation facilities were built in the late 1960s, 1970s and early 1980s. Investment in, or replacement of, assets with deteriorating asset health is increasingly necessary, particularly when ongoing maintenance becomes uneconomic or ineffectual at addressing performance concerns."

Now, for the purposes of Table 10, and the amount of energy that is expected to be generated, does B.C. Hydro ever do something like they do on the transmission side, which is de-rate assets for the purposes of calculating how much electricity B.C. Hydro can generate?

MS. KURSCHNER: A: Our known outage plans are part of the modeling that derives this hydroelectric number.

MR. O'RILEY: A: I mean, certainly individual units at times get de-rated, based on the condition, and Mr. Dunlop could probably speak to that.

MR. AUSTIN: Q: Mr. Dunlop?

MR. DUNLOP: A: Yeah, certainly if there are any particular issues associated with the generating unit, the units can be de-rated. For example, at our Bridge River facility, we have a number of coils cut out of the generator stator, and we're currently running that unit de-rated from approximately 70 megawatts to 60 megawatts. There are a number of similar conditions across the system, and those operating constraints are taken into account in terms of how the system is planned and operated.

MR. AUSTIN: Q: So for the purposes of the figure in column 5, you have included all the de-rating across the generation for the purposes of coming up with this figure?

MS. KURSCHNER: A: The known status, yes, would be included.

MR. AUSTIN: Q: Say for example on page 16 of Exhibit B-10, if there's the reference to the turbine runner failure on unit 3 at G.M. Shrum. Has that been reflected in the figure in column 5?

MS. KURSCHNER: A: Yeah, any time we have an outage like that, it would be part of the input into the model.

MR. AUSTIN: Q: I'd like to refer you to the transcript, Volume 3. Page 392. That's transcript Volume 3, page 392.

MR. O'RILEY: A: Yeah, I have it.

MR. AUSTIN: Q: And this is a response from Mr. Elton, and if you look at lines 24 through 26, it says:

"… I think that was said at one point by Ms. Farrell. You know, she said that specifically with respect to GMS. I was just at GMS, and there's -- you know, three of the ten machines aren't working. …"

Do you see that?

MR. O'RILEY: A: Yes.

MR. AUSTIN: Q: Does the figure in column 5 reflect the fact that three of the ten machines at GMS are not working?

**Proceeding Time 9:28 a.m. T8**

MR. O'RILEY: A: So this was when we were up there in September. One of those three units would have been GMS G3, which we've talked a lot about, so it's reflected. The other two would have been -- one of them would have been the additional cracking that we found on G1, and that arose during the course of a regular maintenance, and so we extended that outage to complete that work. The other was a problem with the stator that we found on G7 in the course of going in to fix the rotor poles on G7, so that was part of a regular capital outage.

Both of those problems were relatively short term in nature in terms of the fix, so they

would not have been reflected in these figures. Though the regular outage, the outage that they were associated with, would have been reflected in the figures.
MR. AUSTIN: Q: I'd like to refer you to Exhibit B-5. This is BCOAPO Information Request 1.34.(a).
MR. O'RILEY: A: Sorry, we're a little behind on this one.
MR. AUSTIN: Q: Exhibit B-5. And I've checked the box on the left. This is 2009-2010 revenue requirements application. So that's B-5, BCOAPO 1.34. --
MR. O'RILEY: A: (a)?
MR. AUSTIN: Q: (a) in brackets.
MR. O'RILEY: A: Yes.
MR. AUSTIN: Q: And as I understand this, this is a chart that shows the health of B.C. Hydro's generation assets. Is that about right?
MR. O'RILEY: A: Yes, that's correct.
MR. AUSTIN: Q: And as I understand your evidence, you just told me that insofar as a generating unit or related equipment has a mechanical problem that you're aware of, this system is in a sense de-rated to reflect that. Is that roughly what your evidence is?
MR. DUNLOP: A: No. Equipment -- the chart that -- the charts, there are three charts attached to the response to BCOAPO 1.34.(a), shows the condition of

the six major assets that -- or six major components that make up a generating unit. And as you'll see in the chart, each piece of equipment is rated good, poor, fair, or unsatisfactory. Equipment can be in poor or unsatisfactory condition and not be de-rated. So equipment can be in poor condition or unsatisfactory condition and still be capable of delivering the full output. The --

MR. AUSTIN: Q: Why don't you do a probabilistic analysis, and for the purposes of determining what your expected energy production might be, include a factor in relation to the health of your equipment? Say for example, if I look at Exhibit B-5, page 2 of 3, second entry on page 2, it says, "Unit 1 at Mica unsatisfactory. Unit 2 at Mica unsatisfactory."

MR. O'RILEY: A: Yes, well, EHR -- maybe I'll just take a step back and explain B.C. Hydro's equipment health rating process. The equipment health rating process is a methodology that provides an objective, repeatable and transparent assessment of equipment health. It also provides what we call a technical prescription, which is the subject matter expert's opinion in terms of what is necessary to restore that piece of equipment to its intended function. And we've developed that methodology for the six major components of a generating unit. The generator, the turbine, the exciter, the governor, the transformer and the unit circuit breaker.

**Proceeding Time 9:33 a.m. T09**

There are, for example, for a generator, there are 13 individual factors that are taken into account in assessing the condition of the equipment. We look at known design deficiencies or problems associated with the equipment. We look at test and inspection data and the tests are based on international standards. We look at the availability of spare parts, both internally within B.C. Hydro and externally in the marketplace. We look at the availability of technical experts to help us deal with any issues associated with equipment. Again, both internally and externally. And finally, we look at the reliability of the equipment, both in the short term and the longer term, and the trend of the reliability.

The reason that the Mica generators are rated unsatisfactory is that there was a problem discovered with the Mica units that the core bolts that hold the stator together were cracking and failing. We retained a panel of international experts to assist us with the evaluation of the Mica stators, and their conclusions were similar to our conclusions, that there was a tremendous risk of failure associated with those units. Those units are rated at 450 megawatts. They are a major component of our supply. We considered that the risk associated with the possible failure of those Mica units was too high, and as a result, we ended up with an unsatisfactory equipment health rating for those stators.

The lead time is long to replace the stators, approximately two to three years from the time we make a decision to replace the stators until we can begin replacing the first stator. We're currently in the process of replacing one stator at Mica each year for four years and, as you can see from the equipment health rating, we've replaced two and we have two yet to be replaced.

In the interim period between becoming aware of the seriousness of the stator core issue at Mica, and until the stators can be replaced, we've implemented a practice of shutting down the units every six months to do a thorough physical inspection of the units and ensure that the condition of the stators hasn't deteriorated to the point that it's unsafe to operate them.

So, although the Mica stators are rated unsatisfactory, they are still operating at full rated output.

MR. AUSTIN: Q: Would you agree with me, despite all those safety checks that you're doing, that because of the bolt problem that one of those units could fail at any minute?

MR. DUNLOP: A: We believe that the practices that we've put in place minimizes the risks of failure of the Mica unit, and minimizes it to a level that's consistent with any other equipment on our system.

MR. AUSTIN: Q: You may have minimized it, but would you agree with me that it could fail at any minute?

MR. DUNLOP: A: No more so than any other piece of equipment in our system.

MR. AUSTIN: Q: And are you basically saying that, despite the fact that some of the equipment that is referenced in Exhibit B-5 is 40 years old or more, for the purposes of availability, you're treating it as brand-new.

MR. O'RILEY: A: Yeah, I mean, I think we are concerned about the assets. I think I talked about that yesterday, and so we've got assets that are -- and pick John Hart, for example, but this first unit went in in 1946. So, 62 years old. And you can see there's a lot of "poors" on the generator and turbine, and we had a failure on the stator this summer with one of those units.

**Proceeding Time 9:38 a.m. T10**

So we are concerned about these older

units. John Hart Ruskin is almost 80 years old. We are concerned, as I talked about yesterday, the runners at GMS and there's 1350 megawatts. We just -- I think your suggestion of coming up with a probabilistic output of the generators, that's not something we've done or considered. I'm not exactly sure how we would actually -- we'd it. But I think your point, are we concerned about the generators and our ability to get the rated output of them? Yes, we certainly are concerned.

MR. AUSTIN: Q: Okay, don't get me wrong. For the purpose of this application you're saying that you need money to rebuild your equipment.

MR. O'RILEY: A: Mm-hmm.

MR. AUSTIN: Q: And not necessarily disagreeing with that at all, but for the purposes of establishing numbers such as the expected output, I'm just questioning whether you should have some sort of de-rate factor in there until you complete your program of overhauling the equipment that you say that needs to be overhauling.

So is that something that B.C. Hydro might consider in the future as its assets are aging and your need to replace them increases, and as evidenced by this application that you've got a plan to do that. So it wouldn't be prudent during the process of essentially rebuilding a lot of these assets, you would put in some sort of de-rate factor for the amount of energy that you can get out of the existing equipment?

MR. O'RILEY: A: It's certainly something to look at. I mean, I think that the question -- yeah, it's certainly something to look at as a way to reflect the risk that we know we're clearing, yes.

MS. KURSCHNER: A: I'd like to add to that. So there are two parts to this. There is the capacity issue factor and -- the capacity issue and then there is the energy issue. So when we are looking at our peak capacity, we do a probabilistic study that has forced outages included in them. So it is taken into account. And if we know that there is a particular -- we generally use CEA outage standards or numbers. If we have any units in the system that we know have a different type of behaviour on forced outages, we would use that information if we have better information. And that's on the capacity so that's taken into account.

Now, if you look at energy, it is a little bit more complicated because -- and what I was going to say is, we have large variability in numerous factors in the system. And you talked about the variability of the in-flows that will overwhelm pretty much everything else. The numbers that you see here are the most probable outcomes. They are the expected, the $50^{th}$ percentile numbers. They are not -- there is a huge range around them. So our probability is that these units, at the expected basis, are not going to fail, so they are not -- so de-rating them would actually cause us to operate the system on the expected basis in a suboptimal manner.

The other thing is that you have to understand, a lot of these plants, we don't run them flat out hour after hour. And we do have some flexibility in the system if there is a unit failure, to deal with it differently, depending which unit it is and where the reservoirs are and so on.

So I think if you put it into the larger picture of these being expected numbers and the variability that we have around there, it would be probably suboptimal to, you know, take a large portion, say, of the Mica unit out just because there is a small probability, albeit catastrophic, of that unit failing.

MR. AUSTIN: Q: I'm not suggesting for a minute that I'd like to see you constrained in terms of your operations, but just for the purposes of the figures that go into something like a rate application. I'm just questioning whether there should be some of de-rate given the age of some of the assets of the system.

Would you agree with me that even if the units were de-rated, that doesn't necessarily mean that you'd have to operate them any differently. It's just for the purposes of deriving figures for the purposes of a rate application you would use the de-rate, and for the purposes of actually operating the equipment there wouldn't necessarily be any restriction.

**Proceeding Time 9:43 a.m. T11**

MR. O'RILEY: A: A de-rate in our language means you actually reduce the amount you get out of the system.

I mean, I hear what you're saying, and we've been telling you about the risk with the assets and the aging assets, and we've got a very aggressive capital plan that we're proposing to deal with that. And I mean, the logic from that follows that there's some risk in our ability to deliver the megawatts and the megawatt hours from the system. I haven't -- I don't think we've thought through how we might reflect that in the application, but the risk is certainly there. How we would reflect that in an application, I'm not sure, but it's certainly there.

MR. AUSTIN: Q: What is the incentive to keep your assets in tip-top shape, other than the pride of the people who work at B.C. Hydro, if all that might happen is that if the energy production from those assets doesn't meet the expected target, the difference essentially goes into a deferral account?

MR. O'RILEY: A: Well, I think we've talked a lot in the past about how we manage the business of B.C. Hydro and we're not like an investor-owned utility that all we care about is our income and our shareholder earnings. So, we have -- we consider very broadly the impacts on the shareholder, on the ratepayer, on other stakeholders in communities that are impacted by these assets. For example, the John Hart, the concern with John Hart is actually less of a reliability issue, less of a dollar issue, it's more of an environmental issue. Because we have the risk of shutting off the flows to one of the best salmon rivers in the province. It's a very, very significant risk for us. So, there is a very broad concern in B.C. Hydro about managing the risks that flow from these assets. Some of them are financial. Some of them flow through the deferral account. Some of them are externalities that we impose on society.

A recent example that had negligible financial consequences, in September, we had an oil spill at Ruskin and, but for the grace of God, it could have been an absolute disaster. We lost -- it turned out we lost 100 litres of oil at a time of year when there wasn't really any impact on the salmon. It could have been 2,000 litres of oil at a time of year when there were fish in the river, either the eggs and the smolts or the returning salmon. So that's -- and that's the risk that goes with having an 80-year-old plant that you're trying to hold together with tape and twine, essentially, until we get the thing replaced.

So that's a risk that doesn't, on the face of it, necessarily flow through the financial statements or the deferral accounts, but it's a risk we take very, very seriously as a company. So, we're not just motivated by the dollars that go to the shareholder, we're motivated broadly by the impacts that we impose.

MR. AUSTIN: Q: One final question in this area before I move on to my last area, and it's along the same lines, Mr. Dunlop. What's your incentive to arm-wrestle an equipment supplier to take currency risk on the purchase of equipment if all that might happen is if you don't do this arm-wrestling match, and B.C. Hydro takes the currency risk, and you come out on the losing end, that it goes into a deferral account?

MR. O'RILEY: A: Yeah, I'm -- I'll answer that question. I mean, we have a huge pride in the company around delivering these projects, cost-effectively in a way that meets our purpose of reliable power at low cost for generations. And we really, really push to execute these projects in the most efficient way possible. And, for example, on Revelstoke, we initially took the currency risk on the turbine, front turbine from Brazil. We took that in U.S. dollars, because we did an assessment that it was going to cost too much for the supplier to take that risk. Subsequently, we locked in, in terms of watching the markets, we locked in that currency risk when the dollar went above parity with the U.S. dollar -- the Canadian dollar went above parity, and we were able to secure a locked-in savings against the project estimate cost. I think it was -- I believe it was $2 million, but we locked in against the project estimates.

So our staff, our project managers, our engineers, are looking for those opportunities every day to deliver these projects on time, on budget, in the prescribed scope. So, if you ask our managers in the company below a certain level, below kind of really the executive level, they don't -- they only have a vague sense of where we have deferral accounts and where we don't. Deferral accounts are not something that is part of the currency of B.C. Hydro and, you know, a middle manager says, "Well, this doesn't matter because there's a deferral account." That's not something people think about, that's not how we talk in the company. It's about, how do we deliver the result for the ratepayer, the shareholder, the stakeholders, and who are impacted by our operations.

**Proceeding Time 9:48 a.m. T12**

MR. AUSTIN: Q: I'd like to move to the final area, and that's Exhibit B-1, page 4-19. So that's the original application. Page 4-19.

MR. O'RILEY: A: Yes, we have it.

MR. AUSTIN: Q: And this is in relation to NERC compliance, which is at line 16, and I believe this is the panel that I'm supposed to ask questions of NERC compliance, is that correct?

MR. O'RILEY: A: Yes. Yes.

MR. AUSTIN: Q: Could somebody just in general terms explain what NERC compliance is or isn't, and how it's going to impact B.C. Hydro's generating assets?

MR. O'RILEY: A: Mr. Dunlop will take that.

MR. DUNLOP: A: B.C. Hydro has been a voluntary member of NERC, the North America Electric Reliability Corporation, and WECC, the Western Electricity Coordinating Council, for many, many years. And we have over those years voluntarily complied with NERC and WECC standards. And it's compliance with those standards that enables B.C. Hydro to interconnect with the North American electricity grid, and that interconnection provides tremendous benefits to B.C. Hydro -- B.C. Hydro's ratepayers. It provides stability to the electric system, and it improves our reliability in the event of a major loss of generation, as Ms. Kurschner described yesterday. Being interconnected with the North America grid enables us to draw on spinning reserve of other utilities to maintain supply to our customers.

It's my understanding that the British Columbia Transmission Corporation is leading the development of a report with input from B.C. Hydro, among others, on the suitability of the NERC standards for British Columbia. The report will discuss any adverse effects of the NERC standards on the B.C. Hydro electricity system, and the costs of implementing the NERC standards. It's expected that that report will be filed with the Utilities Commission in early 2009, and following a review process, B.C. Hydro anticipates that the Utilities Commission will adopt some form of mandatory reliability standards.

The NERC compliance initiative as it's in the application was developed to allow B.C. Hydro to implement and comply with the NERC reliability standards, or other standards that the BCUC would adopt. In terms of the specific work, there's some 35 of 94 NERC standards that have been approved by the U.S. Federal Energy Regulatory Commission that, if adopted by the Utilities Commission, would apply to B.C. Hydro.

MR. AUSTIN: Q: And when I look at the application on page 4-20, and I look at lines 7 through 10, I see it says:

> "The total operating costs of this initiative are $1.2 million in F2009 and $0.9 million in F2010."

And I believe in your update these figures changed somewhat, but not a large amount. And the question I have for you is, is this to study the requirements, or is this for actual physical changes to equipment?

**Proceeding Time 9:53 a.m. T13**

MR. DUNLOP: A: It's not anticipated -- apart from the standards relating to security, it's not anticipated that the other standards would result in a change in equipment. Our expectation is that most of the change will be around reporting, and reporting in detail are what maintenance that we do, particularly to protection systems. And so most of the additional work is around compliance reporting and auditing

requirements that are part of the NERC standards.
MR. AUSTIN: Q: And this is just a follow-up question and if you don't feel comfortable asking [sic] it just let me know. It's in relation to BCTC, is BCTC going to require significant expenditures with respect to its equipment, or we should wait for the report that's coming out later this year?
MR. DUNLOP: A: I'm sorry, I can't answer that.
MR. AUSTIN: Q: No further questions, thank you very much, panel.
THE CHAIRPERSON: The next one in order of cross-examination of this panel is Mr. Wait.

**CROSS-EXAMINATION BY MR. WAIT:**

MR. WAIT: Q: Good morning, Commission Panel and B.C. Hydro Panel. I would like to start first with the electrical -- the consumers, the Commercial Consumers Association IR 1.2.2 from Exhibit B-5. That's the first round of IRs.
MS. KURSCHNER: A: I have it.
MR. WAIT: Q: This has to do with the trading which B.C. Hydro requires for its own purposes where they're avoiding spills or purchasing to make up deficits in our supply. If we look at 2008 on the first page of that, I notice there's quite a bit of power purchased at higher prices. Is that a result of not wanting to run Burrard and buying from the market, or --

MR. O'RILEY: A: Ms. Kurschner can speak to that.
MS. KURSCHNER: A: If you can give me just a minute.
So in any given year we might have periods of time when we are short energy either on a daily shortage or a monthly or seasonal shortage, generally when you see numbers, you know, at this level. Now, you have to remember these are Canadian dollars delivered to B.C. border. But when you're -- you know, when you look at that 50 quintile of prices, that would tell me that generally that would be above our marginal water value and it tells me that it would be driven by some constraints in the system.
I'd have to go back to the history of fiscal '08, which I can do if you give me a minute --
MR. AUSTIN: Q: No.
MS. KURSCHNER: A: -- to see what drove this particular purchasing pattern. But that's what -- generally that's what it would be, constraints.
MR. AUSTIN: Q: Yeah, I'm just wondering if rather than run Burrard you purchased --
MS. KURSCHNER: A: Yeah, and it might be in fact -- I would have to look at when these purchases were exactly made. It might be that we're in fact both running at the same time, but it would be the combination of the economics at that time and reliability factors, how we decide whether we're going

to run -- you know, how much of Burrard we would run versus how much we would be purchasing. And there are times when Burrard actually -- very rarely but Burrard may end up being cheaper than imports. But it is the economics that decides that.
MR. AUSTIN: Q: Yes.
MR. O'RILEY: A: We had an example at the end of March and the beginning of April this year, where the freshet was late and it was relatively cold and we had -- so our load was higher than what it would normally have been at time of year. And we were in a must-buy situation. We had to buy a certain amount of energy a day and I believe it was 20 to 30 gigawatt hours a day. And that coincided with a period of very high market prices, so the gas was in the order of $10 an MMbtu, and the power was equivalently $100. So we bought a significant amount of energy in a three-week period, and that wasn't energy for later re-sale, that was energy to keep the lights on here in the province, because we had this significant constraint.
So when you see the high prices, that's what we're talking about.

**Proceeding Time 9:58 a.m. T14**

MR. WAIT: Q: Yeah, I read the report on that. I'm just wondering if that's what it was.
Just looking at the volumes that are in

that IR, and projected -- if we go to the second page, projected for '09, it's -- your purchases are -- I added up to be 3,530 gigawatt hours. I'm just trying to get a sense of how much power is actually transmitted in different areas, what you require for your uses and what is done in the trade. And I worked that out to be about 10 gigawatt hours a day that you have to purchase, on average, through the year. Now, it certainly wouldn't be a steady thing, it would be bunched up. But does that sound about right?
MS. KURSCHNER: A: I cannot tell you the daily because we don't purchase on a daily -- as you say, it is different periods. So, this -- so the fiscal '09 -- so you added up the volume of the fiscal '09 domestic purchases. Now you were asking about trade and these are all --
MR. WAIT: Q: Keeping trade separate for the moment.
MS. KURSCHNER: A: -- yes, this is separate from trade. This is purely for domestic.
MR. WAIT: Q: Yeah, this is just what you require for your uses.
MS. KURSCHNER: A: That is correct.
MR. WAIT: Q: Yeah. And actually what I did do, I added what you sold, it's about 195 gigawatt hours, put that together, it comes out to about 10 gigawatt hours a day, some -- you're trading either in or out.

And just to get a grasp, that comes, by my figures, to about 425 megawatts per hour that is going through the system one way or another, subject to check, but does that sound like about the right range when you're --

MS. KURSCHNER: A: I'm sorry, I'd have to do the math, because that's not how I think about it at all. I think about the annual totals because they do come in very concentrated amounts. So, basically what this tells us is, and I believe this was based on the RRA, not the evidentiary update, when you add up the volume totals, that is on an expected basis what we are going to be buying. Now, this is fiscal '09. A lot of those purchases would have happened in April/May. In April it was driven by our constraints of not being able to generate more out of the Peace generation and Mica. And then there would be economic buying throughout the rest of the period.

And again, you know, going into this winter, we expect that between now and the end of March, we have -- we are short energy, seasonal energy, because of the constraints that we have at running Mica so that we fulfill the obligations of the Columbia River Treaty with respect to Arrow flood control.

MR. WAIT: Q: Okay. On your trading for the purposes of B.C. Hydro, am I correct that there is a wheeling

agreement of probably around 275 megawatts
specifically for Seattle City Light on the Skagit
Treaty?
MS. KURSCHNER: A: So, treaty --
MR. O'RILEY: A: Can I just jump in and say, you're --
we're not actually trading for B.C. Hydro. We're
acquiring energy to meet our domestic load, and at
certain times you can see these surplus sales. We're
in -- under certain conditions, we're having forced
sales because the reservoirs are full to the brim and
about to spill. All that trading is done -- all those
purchases and sales are done through the transfer
price agreement with Powerex, and we don't consider
that trading. We consider it procurement or
purchasing of energy for our system.
So I just want to just perhaps stick to
that terminology, if you would -- if we can.
MR. WAIT: Q: Okay. For domestic uses, or --
MR. O'RILEY: A: Yeah. We're purchasing.
MR. WAIT: Q: Okay. Yeah. Getting back to my question
on the Skagit, am I correct that there is an agreement
for wheeling of probably about 275 megawatts -- at
least 263, year-round at any time they want that, they
have to be able to get it?
MS. KURSCHNER: A: I believe that Skagit, the agreement
is -- the capacity on it is 310, if I remember

correctly, and the energy -- I'd have to look that up what the annual energy is, but I'm thinking it is about 340 or so gigawatt hours but I'd have to look it up.

**Proceeding Time 10:07 a.m. T15**

MR. WAIT: Q: I thought it was 310 and 263 capacity.
MS. KURSCHNER: A: It might vary from year to year too.
MR. WAIT: Q: Yeah, but anyway there's this block around --
MS. KURSCHNER: A: Yes, there is.
MR. O'RILEY: A: Perhaps for the Panel's benefit, there is a long-term obligation that the Province of B.C. has through a treaty with Seattle City Light, and that related to the Skagit. The fact that the Skagit -- High Ross Dam was not built and flooded back into Canada. So we have this obligation to deliver power. They pay for that power on a rate, essentially a cost-based rate, and there's some complicated accounting because it's an 80-year deal and such. We can explain that. But it's a commitment. That commitment flows down to generation, and that power is provided on firm B.C. Hydro transmission to the border and then firm Bonneville transmission directly to Seattle. And all those costs, the costs of that transmission flow back to the generation group.
MR. WAIT: Q: Yeah, okay. My concern is that firm

transmission in the U.S., is that strictly into Seattle or is that through the Washington system such that you could use it to go to mid-C with power?

MR. O'RILEY: A: When -- that agreement is such that we don't deliver power every hour of every day. When we're not using that power to deliver on the Skagit Treaty, that transmission is made available to Powerex to utilize and capture trade margin from just as -- it's an asset like any other asset of B.C. Hydro and they use it -- they use surplus capability to earn trade margin. And that margin flows back to B.C. Hydro ratepayers through the trade income --

MR. WAIT: Q: Okay, yeah. Where I'm going with this is, when you are, for domestic purposes, buying power or selling to avoid spill, do you get the benefit of this wheeling that you have, or do you pay wheeling on your first 250 or 300 megawatts and Powerex? Because under the trade agreement --

MS. KURSCHNER: A: Well, it is one-directional, the transmission, right? So it doesn't apply on purchases. It applies to sales. And the question on, through the transfer pricing agreement, whether the transmission would be netted out, we don't know. I don't know.

MR. O'RILEY: A: Yeah, we don't. I can probably answer that based on my recollection of the agreement. We buy the -- the energy we buy from Powerex is acquired or transferred at the B.C. border, and they provide the transmission. We don't get a credit back for any unused portion of the Skagit that they could conceivably use for purchases for B.C. Hydro. So all of our transactions are at the border, and the transmission costs all flow to Powerex. And I think what you're getting at and you're correct, is that they get the benefit of the surplus capability of the Skagit Treaty, and there's not a direct flow back to generation or B.C. Hydro. The benefit that they earn flows back to ratepayers through the trade income.

MR. WAIT: Q: Yeah, and my concern with that, of course, is the $200 million cap on that, that there should be maybe some changes made there.

Okay. I gather there's a couple of undertakings already on the total amount of power that is in the trading account that you buy and sell to Powerex in the system. So I won't look at the yearly amounts but can you give me an idea of how much in a day they might -- their ranges would be? Probably anywhere from zero to -- how large would their trading requirements be that you would deliver to them or buy from them?

MS. KURSCHNER: A: I mean, if we take it to an extreme and there are no constraints to this in the generating system, they could fill the tie all around the clock. Now, that's not what actually will happen because it wouldn't be economical, but that would be the limit.

MR. WAIT: Q: Yeah. No, I'm wondering just how it is working now, and what its effects are on the Hydro system, is what I'm driving at.

**Proceeding Time 10:08 a.m. T16**

MS. KURSCHNER: A: Well, what is important to remember is that Powerex, only through the transfer pricing agreement, has access to surplus capability of the system. And as Mr. O'Riley was noting yesterday, we have been -- over the years that surplus capability has been diminishing and diminishing. And if you think about the situations where, for domestic needs, we are purchasing large amount of energy because we're in a constrained situation, just like we were this past late winter and early spring, actually even into late spring, there is no room for Powerex to be selling. We're energy-short. They might be doing some small daily exchanges, but their ability to utilize the system for trade income has been diminishing over time, and there are extensive periods of time now where they have -- there is no surplus capability.

MR. WAIT: Q: Okay. We got the capability intertie at Sumas the other day at about 2,000 megawatts.

MS. KURSCHNER: A: Coming into --
MR. WAIT: Q: Either way, I would assume.
MS. KURSCHNER: A: No, it's going out of B.C. it's higher. I believe it's 3200.
MR. WAIT: Q: 3200 out. Okay. And what about the Alberta tie? How much?
MS. KURSCHNER: A: Okay, the Alberta tie is a complicated tie. Its thermal rating is roughly 1,000 megawatts, but it never operates in either direction -- or it never is made available in either direction to that full amount -- never has been, as far as I can remember. Alberta has some serious problems with system stability internally within the province, and that limits the amount that can be put on the tie. And it is driven by particular distribution of their generation at the given hour, and their load levels, and the season, and there are tables that specify for every month going forward how much there is going to be available and it varies. There are some hours when there is nothing. There are some hours where it might go to, you know, 400, 500. But it is -- it fluctuates, and it's driven by all these other inputs. So there is nothing typical about that tie.
MR. WAIT: Q: Okay. And I think you've got another tie around Nelway? In the interior?
MS. KURSCHNER: A: That's the eastern portion of the

U.S. tie. And when I say -- when I said the 3200, that meant both.
MR. WAIT: Q: Okay, 3200.
MS. KURSCHNER: A: The full -- yeah.
MR. WAIT: Q: Yeah, it's both of them. Okay. And what I'm trying to get an idea of, just on a daily basis, is how much they would range. Because on B.C. Hydro's own stuff, you can probably range up to a thousand megawatts, I would think.
MS. KURSCHNER: A: Sorry, and what do you mean --
MR. WAIT: Q: On what you're trading for domestic uses, when you're having to bring in, or --
MS. KURSCHNER: A: There is no -- so, I think when you -- what you have to look at is the consolidated capability. The allocation then is based on the economics of what domestic needs. So I think what you're talking about is the physical capability to take energy into the system. If domestic needs to be bringing energy into the system, that much less is left for Powerex to bring in, and they will be bringing in the energy that is priced above what domestic is bringing in. So, domestic has access to the cheapest energy in the market.
So I think what you're talking about is the physical capability on a consolidated basis to bring energy into the system.

MR. WAIT: Q: No, actually what I'm trying to get down to is the operating procedures B.C. Hydro has to go through to meet the trading requirements of Powerex, when they can sell power into the market or they're buying power back.

**Proceeding Time 10:13 a.m. T17**

MS. KURSCHNER: A: Ah, okay. Okay. So, operating procedures. So, the process around that is -- and I spoke about this a little bit yesterday, you know, it starts with our sort of annual outlook and it, you know, on a -- then as we progress through time on a monthly basis, we let them know what we think the surplus capability in the system is going to be. And then as you move through the time all the way up to that -- up to the day ahead point, Powerex and our real time dispatch operations would discuss what Powerex expects to be doing in the market, and what it is that we need to be doing for domestic, and what the ability of the system is to produce or back off to take energy in or get it out. And from that, Powerex will get some directions in terms of this is what you have available, and they will then trade based on that and of course based on the economics. And that gets then refined, so on a day ahead basis they might do some trading on it in a day ahead markets. And then we get into the real time markets and then the same situation will happen again in real time.

And for example, there might be a situation where, you know, the markets all of a sudden you have an outage in the Pacific Northwest and markets all of a sudden will go very high, and Powerex -- Powerex and the real time operations sit right next to each other in the same office, and Powerex will, you know, come and say, "Look, this is what is happening in the market, what I'll change -- squeeze out of the system." And our real time shift office will do whatever they can because the economics is there to create trade income.

So there is this ongoing interplay between the ability of the system to generate or take energy in, and what Powerex sees in the market.

MR. WAIT: Q: Okay. Let's take basically this time of year.

MS. KURSCHNER: A: Mm-hmm.

MR. WAIT: Q: B.C. Hydro would certainly have a surplus of capacity.

MS. KURSCHNER: A: Oh, not certainly, no. Not at all. No. This is actually -- spring and fall are typically the two times when we're -- well, actually we're getting capacity shorts all the time now. Spring and fall are the times when we do most of our outages. And that means that generally in the last few years, in spring and fall, we are very tight on capacity. The difference from -- we watch winter very carefully. The difference is in winter the chances of the market being either extremely expensive or not being there to get the supply, is quite different than the spring and fall, where generally the markets elsewhere are pretty settled, and we know that we can bring energy in at reasonable prices. It doesn't always unfold that way. But this is not the time when we have huge amounts of surplus capacity as a rule.

MR. WAIT: Q: Mainly because of the maintenance.

MS. KURSCHNER: A: That's correct.

MR. WAIT: Q: Okay. Yeah, I would have expected some surplus so that you would normally have a threshold price. And I was just wondering --

MS. KURSCHNER: A: You know, I think you're trying to get at some numbers.

MR. WAIT: Q: Yeah.

MS. KURSCHNER: A: And I know, and it's really hard for me to generalize what a daily profile would look like. But I can give you an example of what has been happening. I've got -- unfortunately the last time I picked this up was 15th of October, so that would have been late last week. So between the 1st and 15th of October, domestic imported 146 gigawatt hours of electricity into the system, and trade import. And when I talk about this it has to be understood that the trading is all done by Powerex and it goes through the transfer pricing agreement.

MR. WAIT: Q: Yeah.

MS. KURSCHNER: A: But the allocation. 146 gigawatt hours went into domestic, and 126 gigawatt hours went to trade.

MR. WAIT: Q: Okay. And now on that trade you've imported that -- and I'm assuming you would sell that back at some point.

MS. KURSCHNER: A: Sorry, sorry, sorry, sorry. Actually the net it's hundred -- there was 125, 126 gigawatt hours that went into the trade account, and 27 gigawatt hours that went out of the trade account. So on a net basis, give or take 100. 99 gigawatt hours.

MR. WAIT: Q: Okay. Now, how do you handle -- how does Hydro handle that when they put power into the trade account?

**Proceeding Time 10:19 a.m. T18**

MS. KURSCHNER: A: Okay. So under the transfer -- it's all specified in the transfer pricing agreement, and the accounting goes -- when power is brought into the system, if the price of that energy was below domestic buy price, that power, or that energy, will be allocated to the domestic trade account. If that energy was brought in above the domestic buy price, that energy will get allocated to the trade account. So, domestic at any given time will have a domestic buy price set as an economic signal. Anything below we will take into domestic. If there is energy that comes into the system above, that is Powerex's choice for trading, and it goes into the trade account.

MR. WAIT: Q: And when this happens, that power is used within the B.C. Hydro system, because otherwise --

MS. KURSCHNER: A: When you say "used" what do you -- when that happens, it means when we bring energy in --

MR. WAIT: Q: You reduce your production of power.

MS. KURSCHNER: A: -- it means we -- it -- that's right. It goes against serving load, or it reduces production and gets stored as water.

MR. WAIT: Q: Okay. And then when they draw on that trade account, you rev up the generators for that extra.

MS. KURSCHNER: A: And just to be clear, that energy that is brought in and allocated to the trade account, it in fact is sold to B.C. Hydro and it goes into the non-Heritage cost of energy. And then when Powerex wants to sell it out, it gets taken from the non-Heritage cost of energy at the weighted average cost of the purchases, gets resold to Powerex, and then gets taken out of the trade account balance and

Powerex sells it into the market and has gains in the trade income.

I'm sorry, what was your original question?

MR. WAIT: Q: Actually, I hope I'm following it more than most.

MS. KURSCHNER: A: Well, I just always worry about, you know, there are some very -- we have to be very careful about how we represent the sales out of the system and purchases into the system. Powerex does the trading, but Powerex does not own any water specifically in our systems. It doesn't sit in particular reservoirs. It's not theirs. It gets sold to B.C. Hydro and then B.C. Hydro sells it back when we can, when we have surplus capability, for them to re-sell to the market.

THE CHAIRPERSON: Excuse me, Mr. Wait. You did get hold of the copy of the transfer agreement?

MR. WAIT: Yes, I did.

THE CHAIRPERSON: All right, good. Thank you.

MR. WAIT: Q: Yeah. And I may have some questions on that later.

Okay, so the net results at the end of the year is what the non-Heritage power costs in this account, then, I gather?

MS. KURSCHNER: A: The trade account, anything that is in the trade account will be reflected in the non-

Heritage cost, yeah.
MR. WAIT: Q: So it's the balance. Okay. Now, B.C. Hydro sets the thresholds for buy and sell?
MS. KURSCHNER: A: Generally, because we have been, for the last few years, in such a large deficit position we only right now have a price, a buy price. When you see the sales out of the domestic account, it really is to manage the reservoirs prior to the filling season. And at that point, it really is not based on a price signal. At that point, we start operating more on a physical water management --
MR. WAIT: Q: Spill signal.
MS. KURSCHNER: A: Yeah. So, now, that said, if we -- you know, if we were to get in the future, into a surplus position, we would be setting domestic sell price as well.
MR. WAIT: Q: Okay. Without a domestic sell price, my understanding was that Powerex would sell at high load hours and buy back at low load hours. How do they trade much, then, with the B.C. Hydro system?

**Proceeding Time 10:23 a.m. T19**

MS. KURSCHNER: A: So generally all the sales that you would see would be Powerex's sales out of the trade account, with the exception of these few circumstances when we need to sell out of the domestic accounts for the purpose of management of the risk of spill.

MR. O'RILEY: A: So they set their own buy and sell price.
MR. WAIT: Q: Yeah, maybe --
MR. O'RILEY: A: That's independent of the buy and sell price that we might set for generation, or for domestic.
MR. WAIT: Q: Yeah, maybe we should take a look, then, at the transfer pricing agreement, Exhibit C6-7.
Maybe before we get into that, we should take the morning break.
THE CHAIRPERSON: Let's do that. Fifteen -- oh, Mr. Christian?
MR. CHRISTIAN: I was just going to say maybe as a last follow-up before we break, some of the discussion that's the subject of this cross-examination, surplus sales in particular, is addressed in the application, section 3.4.3.7 on 3-9. There's a paragraph there that describes I think what's the subject matter of this examination.
THE CHAIRPERSON: Thank you, and we shall return in 15 minutes.
**(PROCEEDINGS ADJOURNED AT 10:25 A.M.)**
**(PROCEEDINGS RESUMED AT 10:42 A.M.) T20/21**
THE CHAIRPERSON: Please be seated.
Mr. Wait, we shall continue with you.
MR. WAIT: Thank you, Madam Chairman.

MR. WAIT: Q: We're going to look at Exhibit C6-7, the transfer pricing agreement, on page 10, I believe it was. Yeah.
MR. O'RILEY: A: Thank you. We've got it. Page 10, you say?
MR. WAIT: Q: Page 10, yeah.
MR. O'RILEY: A: Okay.
MR. WAIT: Q: Looking at section 6.1:

> "Subject to section 6.3…"

Which is the constraints of the system,

> "…at any time when Electricity Transfer Price is expected by Powerex to be greater than the Threshold Purchase Price or when B.C. Hydro does not require electricity from Powerex to serve Domestic Load, Powerex may schedule and deliver electricity for sale to B.C. Hydro."

This is B.C. Hydro -- or Powerex just doing their own trading and using the B.C. Hydro system. Sort of as the bank, if you will.
MR. O'RILEY: A: Yes, this is putting in -- this is putting energy into what we call the trade account for later re-sale.
MR. WAIT: Q: Yeah.
MR. O'RILEY: A: By Powerex.
MR. WAIT: Q: Yeah. And what does this do to the B.C.

Hydro system in the sense of operating the system?
MR. O'RILEY: A: I'll let Ms. Kurschhner talk about that.
MS. KURSCHNER: A: It will back off other generation.
MR. WAIT: Q: Shut down generation and back off some of it, and --
MS. KURSCHNER: A: Or use -- yeah.
MR. WAIT: Q: Is there any particular plants where this is done? More than others?
MS. KURSCHNER: A: This is optimized by our real-time dispatchers, depending on what is happening in the system. They will have a preference of which units they will decide to back off.
MR. WAIT: Q: Okay. And we have the same thing on the sell side, where Powerex can sell power and require it from B.C. Hydro, provided you have the capacity to deliver. And that then requires you to start up units or increase the flow-through units, which is not a big deal if it's just increasing the flow.
MS. KURSCHNER: A: Again, we will look at the system, and the dispatchers will decide what is the most economical and best way to increase the generation to effect those sales.
MR. WAIT: Q: Okay. I'd like to get back to that threshold price. You set one to sell and one to buy, at times. What would you use as the criteria for the

difference?
MS. KURSCHNER: A: As I said, currently and as far as I have been in this role, I can't recall that we have actually had a sell price, because we're just in such a short position, so it's always domestic, it's always buying. The domestic buy price is set by assessing the needs to serve the domestic load, and our obligation over the next three to five years.
MR. WAIT: Q: Okay. So that basically the only buying and selling that is done strictly for the sake of that is initiated by Powerex, then, under this section 6.1/6.2?
MR. O'RILEY: A: Yes.
MR. WAIT: Q: Okay. And how quickly would they replace the power, either way, when they do trade it on that trade account?
MS. KURSCHNER: A: They may -- it may be within a day. It may take several years. So it just depends, what is happening in the market? What is the -- again, everything that we do is intended to maximize the long-term benefits to the ratepayers. It is not evening out the years or maximizing one year on the account of other years. It is to maximize over the long period of time. So depending on what is happening with markets and the inflows and the loads and so on, that is part of the equation.

**Proceeding Time 10:47 a.m. T22**

MR. WAIT: Q: Okay.
MR. O'RILEY: A: If you go back to the early years of this agreement, there was actually considerable capability to allow Powerex to do year over year. So they could put energy in one year, take it out the next year. And what we've seen with the load growth on the system and the various constraints we've talked about is those windows shrinking. There's some ability to put in energy in one season and take it out in one season -- a next season, but even that is constrained. So more and more of their activity is being pushed into shorter and shorter-term windows. And the year over year is virtually gone, because that storage is required to meet the domestic load.
MR. WAIT: Q: I guess I haven't appreciated just how much the system is stressed over the last few years. Okay. I'll move on to something else then.
From the questions from Mr. Wallace regarding the shear pins, I won't particularly concentrate on the shear pin but -- what is the situation with Hydro generally in regards to replacement parts? Mr. Dunlop was up at the Shrum generating station where they've got ten generators. I assume they're all the same basically?
MR. DUNLOP: A: No.

MR. WAIT: Q: No?
MR. DUNLOP: A: The generators at G.M. Shrum are not the same. Units 1 to 5 were installed at the same time, so Units 1 to 5 are similar. Units 6, 7 and 8 are similar. And Units 9 and 10 are similar.
MR. WAIT: Q: Okay. How do you stock replacement parts, as in generally what would be the policy on that?
MR. DUNLOP: A: As part -- I talked yesterday about implementing reliability centred maintenance, and as part of developing the maintenance standards, using the reliability centre maintenance methodology, spare parts are identified as part of that process, spare parts that are appropriate to maintain on site, and -- so one of the outputs of the RCM methodology is recommendations around spare parts to maintain on site. They're physically maintained at G.M. Shrum, they're physically maintained in a warehouse facility.
MR. WAIT: Q: Yeah, we've just gone through a situation with Fortis where they have requested the transformer which is special voltages or non-standard voltages for their excitor motors, so that their system happens to be quite similar such that it could be interchanged with any of the generators.
MR. DUNLOP: A: Yes, and certainly for the larger pieces of equipment such as transformers, such as

excitors, we look for opportunities of purchasing what we call a system spare, which can be designed in such a way that it can be used at any number of facilities in the case that it's needed.

MR. WAIT: Q: Yeah. Okay.

MR. O'RILEY: A: I think what I could add to that is I think the challenge there was clearly there wasn't an adequate spare available when there were the failures prior to this event and they put in this shear pin from a box that was "Do not use." And I think the reason there wasn't an adequate spare there is that there hadn't been an appreciation of the link between the shear pin failure and the catastrophic failure of the units. And we had done extensive studies of that unit going back to the dispute with Mitsubishi over the warranty protection, and in through the course of all that activity, all that study, we weren't able to demonstrate that there was an increasing -- an expectation of an increasing need for maintenance of those runners. Or any link between a -- you know, a shear pin failure and failure of those runners.

**Proceeding Time 10:52 a.m. T23**

And we ended up with a fairly modest settlement with Mitsubishi as a result of that, And then later in the nineties we studied it again, for the purpose of evaluating the decision to replace the runner, and through the course of all that work we didn't identify that failure mode either. And then again in 2004, when we made another run at replacing the runners, and the assumption was that they could be maintained, you know, with relatively modest annual welding, and there wasn't -- it wasn't clear from the work that was done that there was this failure mode, even though we had some fairly senior individuals with long, long careers and extensive experience on turbines and such involved in those analyses.

So I think that's the reason that the critical spare wasn't identified and unfortunately the imperfect shear pin was used.

MR. WAIT: Q: Yeah. Okay. And the other thing I wanted to get clear is you have about 400 megawatts of curtailable load, if required, and is that a last resort if that power is not available on the market, or does it depend on a market price before you --

MR. O'RILEY: A: Well, I think Ms. Kurschner talked about that yesterday, so I'll defer to her on that.

MS. KURSCHNER: A: It's not a last, last resort, no. In any -- the situation when we call on load curtailment can unfold in many different ways, and it -- there are many variables that will come into it. But no, it is not the last resource.

MR. WAIT: Q: So it could come before power is

available, or when power is available. But --
MS. KURSCHNER: A: Yes.
MR. WAIT: Q: Assuming it can be imported.
MS. KURSCHNER: A: Yes, it could come before imports, yes.
MR. WAIT: Q: Yeah. Okay. Thank you, those are my questions.
THE CHAIRPERSON: Thank you, Mr. Wait.
Next, I see Mr. Meade is in the back of the room there, so I'm -- please come forward.

**CROSS-EXAMINATION BY MR. MEADE:**

MR. MEADE: Q: Hello. I've got just a few questions here about salmon enhancement in watersheds, and the cap -- dams.
MR. O'RILEY: A: I've got those questions. I just need to find the -- we received those questions in advance, so I just want to pull my notes.
Okay, thank you, I've got them.
MR. MEADE: Q: The first two questions, what number of dams have been built by B.C. Hydro, and what number of dams have been acquired by B.C. Hydro that have limited or blocked salmon migration to upstream spawning grounds?
MR. O'RILEY: A: Well, we answered those questions together. A number of the dams that we're talking about were built by predecessor companies or by other

companies that were subsequently acquired by B.C. Hydro, and the answer is 8 or 9. And the reason there's a discrepancy there is, there is -- on the Ash River there is some debate about whether salmon made it as far as the headwaters above the dam, because there was a downstream blockage that was more recently removed. And so there's a difference in view on whether the --

MR. MEADE: Q: So those 8 or 9, they were acquired dams, is that right?

MR. O'RILEY: A: They were a mix. If I look at the list, Puntledge, Comox, those would both have been built by the B.C. Power Commission. Well, Puntledge would have been originally built by the coal company over there, and then subsequently taken over by the Power Commission and then by B.C. Hydro. Seton Dam would have been built by B.C. Hydro. The salmon diversion, which is part of the Campbell system, was built by the Power Commission. Coquitlam Dam was built by B.C. Electric. Alouette by B.C. Electric. Ruskin by one of the -- I believe that was Electric. And Terzaghi was B.C. Hydro. Wilsey, I think, was a predecessor company, and Elsie was the Power Commission.

So they're all different companies that ended up being part of B.C. Hydro.

MR. MEADE: Q: And above these dams, the salmon habitat has been destroyed? Or has there been measures taken to alleviate that?

MR. O'RILEY: A: The salmon habitat above the dam would have been impacted. In some areas we've got fish passage structures and downstream structures. So for example at Seton, there's a vertical slot fish ladder that allows the sockeye to get above the dam and then we have operating mechanisms where we allow the smolts to escape below the dam and get back into the Fraser River.

**Proceeding Time 10:57 a.m. T24**

In the case of Coquitlam Dam, that was an example where the dam was completely blocked the salmon flows, and we ended up with a landlocked population of Kokanee fish, and there's been some successful efforts in the last couple of years to release Kokanee fish from behind Coquitlam Dam and they've gone out to sea and they've re-anadromized and they've come back as sockeye salmon and we've been able to trap them at the base of the dam in a structure we built and bring them back up above the dam. So that's quite a historic, really, thing that we've been able to achieve. And we've done a similar thing on the Alouette River.

So that the habits above the dam has been

impacted in various ways, typically by raising the level and reducing the amount of spawning habitat.
MR. MEADE: Q: And you're physically transferring fish from below the dam to above?
MR. O'RILEY: A: At Coquitlam and Alouette we are doing that.
MR. MEADE: Q: What's the cost of that?
MR. O'RILEY: A: It's been relatively modest, in probably the twenties of thousands of dollars. It's like under $100,000. And that's funded from our -- in both cases from our bridge coastal restoration program, which is one of three compensation programs we have to mitigate what we call the footprint impacts of our facilities.
MR. MEADE: Q: So is the effect of that, when you physically transfer, would that give you the same result as putting in fish ladders?
MR. O'RILEY: A: We've only seen -- at both Alouette and Coquitlam we've seen a relative handful of salmon come back. So for now we're just looking at this what they call trap and truck. We've committed with the stakeholders and the First Nations in the valley to continue our efforts to build the stocks there and to monitor the results of the returns, and we have not made any decision on a physical fish ladder or fish passage one way or another. It's something we would

look at down the road, depending on how the -- really an experiment because this is the first place it's been done anywhere in the world, you know, recreating a sockeye run. We want to see how that unfolds.
MR. MEADE: Q: If you're successful there, to what extent would you expand it throughout your system, these other dams that I take it that they're negligent, would you try and -- try the same methods there to bring back the salmon?
MR. O'RILEY: A: It depends on the circumstance, so some of our facilities -- there are other dams downstream. So that Columbia facilities, for example, have -- there are dams in the U.S., like Grand Coulee, for example, that blocks access to the salmon getting up to, you know, the base of our dams. There's certainly interest among the stakeholders and First Nations involved in the various streamkeeper groups to try and -- try the same experiment in other places.
I should say it's not the only thing we're doing in terms of restoring fish habitat. We have been quite successful at places like -- well, Campbell River in particular, at enhancing the downstream, the habitat downstream of the dam. And we've been working with partners, local community groups, streamkeeper groups, the First Nations. The agencies to DFO and Ministry of Environment have created a number of

salmon channels and spawning channels, salmon spawning channels in various ways to grow the numbers of other salmon, like the chum and the coho and such, the spring, downstream of the facilities. And that's been pretty effective and pretty cost-effective. It's been a really good to build relationships in the communities. Like we have some tremendous relationships as a result of that in the Campbell River area, as a result of those efforts over the last ten or fifteen years.

MR. MEADE: Q: As I understand it, the American dams on the Columbia, they are trying to fix the problem, right? They're trying to put in fish ladders or -- I don't know whether they're catching and trucking or whatever it is. Am I correct in assuming that?

**Proceeding Time 11:02 a.m. T25**

MR. O'RILEY: A: They do a lot of different things. I think mainly they do barging. And they do some -- I don't -- I think the numbers are -- I'm not sure whether they do trap-and-truck, but they do a lot of barging upstream and downstream.

MR. MEADE: Q: Is it -- how long have they been doing this?

MR. O'RILEY: A: I'm not aware of how long they've been doing it. For a while. Certainly since the nineties.

MR. MEADE: Q: Is that allowing salmon to come up into

the Canadian system?
MR. O'RILEY: A: I don't believe any salmon are getting past the Grand Coulee Dam. I'm not an expert on the U.S. system, so --
MR. MEADE: Q: Right.
MR. O'RILEY: A: There's certainly no -- as far as I know, there's no salmon in the Canadian portion of the Columbia, so I don't believe they're getting above the Coulee.
MR. MEADE: Q: So the Grand Coulee is the major block and, as far as you know, there hasn't been any effort by the Americans to --
MR. O'RILEY: A: I'm not -- I probably can't say one way or another what they've done to try or not try.
MR. MEADE: Q: Okay. Okay, that's my questions, thank you.
MR. O'RILEY: A: Thank you.
MR. MEADE: Q: Thank you.
THE CHAIRPERSON: Thank you, Mr. Meade.
Mr. Fulton, you are next.
Just before you get started, a little time management issue. When you are getting close to 12 and looking for a good opportunity to break, we would like today finished a few minutes earlier because of a conference call, but even like 3 minutes to 12 would be fine. But just make sure you don't run over.

MR. FULTON: Yes, thank you, Madam Chair.

**CROSS-EXAMINATION BY MR. FULTON:**

MR. FULTON: Q: Good morning, panel.
MR. O'RILEY: A: Good morning.
MR. FULTON: Q: I want to begin my cross by doing a number of follow-ups from questions that arose earlier in the proceedings, and are reflected in the transcript. So that the volumes that I'd like you to have of the transcript are Volumes 12, 11 and 6.
And I'd like to begin with 12 in an exchange that you, Mr. O'Riley, and you, Mr. Dunlop, had with Mr. Wallace yesterday on Exhibit B-50. And in particular, the table that is referenced at the beginning of page 11 of B-50 and appears at page 12 of B-50.
THE CHAIRPERSON: Do you have a reference also in the transcript?
MR. FULTON: Yes, I do, Madam Chair. So the reference in the transcript is at page 2004, beginning at line 16.
MR. O'RILEY: A: I have that.
MR. FULTON: Q: And actually, if we go to 2024, the discussion on B-50 began at transcript 2004, but I'd like to go particularly to 2024.
MR. O'RILEY: A: I have that.
MR. FULTON: Q: And do you also have the table that is at page 12?

MR. O'RILEY: A: Yes.
MR. FULTON: Q: Of Exhibit B-50. And the exchange on the table begins at line 16, at 2024, and then at page 2025, Mr. Dunlop, you agreed that the table was an accurate reflection of the amount of service that was acquired from generation maintenance services, and that's at lines 7 and 8. Do you recall that evidence?
MR. DUNLOP: A: Yes.
MR. FULTON: Q: Okay. And Mr. O'Riley, dropping down to line 25 on page 2025 and continuing on to line 7 of the following page, you agreed that consistently up until 2008, GMS under spent their budget by substantial amounts.

**Proceeding Time 9:05 a.m. T2**

MR. O'RILEY: A: Yes, and I should clarify it was with reference to this particular budget, a line item. So I don't believe that I would say they underspent their overall budget. This is a small -- they have roughly an $11 million budget, so this is one line item in an $11 million budget.
MR. FULTON: Q: Right, okay. And your answer went on to say that

" It's part of the learning and continuous improvement process that we go to, and we will take these learnings and apply them to other stations and that's how we get better overtime."

And when you were referring to other stations, were you referring to other generating stations such as Mica and Peace Canyon and Revelstoke?

MR. O'RILEY: A: Yeah, I would probably have -- GMS is the headquarters with the management structure there, and probably more accurately should have said to other headquarters, which may look after a number of stations.

MR. FULTON: Q: And so those other headquarters would have been GMS and Mica and Revelstoke.

MR. O'RILEY: A: There's a Mica, Revelstoke, there's a headquarters at Seven Mile and at Kootenay Canal, and then three in the coast area.

MR. FULTON: Q: Okay, what about Peace Canyon?

MR. O'RILEY: A: Peace Canyon is part of the Peace region, so I would include that as part of the Peace area, together with GMS.

MR. FULTON: Q: Now, has B.C. Hydro reviewed the approved and the spend, the actual spend numbers for those other facilities such as Mica and Revelstoke and Peace Canyon to see whether there is the same profile in terms of underspending of approved amounts at those facilities that there were at GMS?

MR. O'RILEY: A: So I just got this report last week or the week before, so I've not -- we've not, as far as I

know, we've not done that, Mr. Dunlop?
MR. DUNLOP: A: No, we have not.
MR. FULTON: Q: By way of undertaking could I ask you to provide a table similar to the table that's at page 12 for Peace Canyon, Mica and Revelstoke, so that it would show that the approved amounts to be spent and the amounts that were actually spent for the same timeframe?
MR. CHRISTIAN: We'll do that if it's possible, and I'm just not sure that it's possible. Is that information --
MR. O'RILEY: A: We'll certainly try.
MR. CHRISTIAN: We'll try.
MR. O'RILEY: A: We'll try.
MR. FULTON: Q: Thank you.
MR. O'RILEY: A: I have no reason to think it won't be, but --
MR. FULTON: Q: And if there is any other station that you want to include as well --
MR. O'RILEY: A: Sure.
MR. FULTON: Q: -- in the table, do feel free to do so. Thank you.

**Information Request**

MR. FULTON: Q: We can put away B-50 now, but keep the transcript because I will come back to transcript Volume 12.

The next series of questions that I have relates to labour strategies, and I had originally canvassed this matter with Mr. Rodford. And so transcript Volume 11, page 1864, and to put the questions in context you should probably also have before you, in addition to page 1864, Exhibit B5-1, the response to BCUC IR 1.50.5, which shows the total costs for the labour strategies initiative as 4.8 million in fiscal 2009, and 7.1 million in fiscal 2010.

MR. O'RILEY: A: Yes, I have that.

MR. FULTON: Q: And beginning at line 14 of page 1864, Mr. Rodford spoke of the field operations components of the 4.8 million and the 7.1 million and he described three buckets that occasioned the increase. One was the apprenticeship program, the second, I believe, was the training materials, and the third was international recruitment.

Can you tell us what portion of the 4.8 and the 7.1 belongs to EARG?

**Proceeding Time 11:12 a.m. T27**

MR. O'RILEY: A: Yes. In fiscal '09, the figure is 2.3 million, and in fiscal '10, the figure is 2.6 million.

MR. FULTON: Q: And can you tell us the reason for the increase between fiscal '09 and fiscal '10?

MR. O'RILEY: A: Well, in our case we have three buckets. They're slightly different buckets than Mr. Rodford referred to for field operations. So we have what we're calling an increment to our strategic work force planning, so additional trainees and associated expenses. And in fiscal '09, that was 1.1 million. In fiscal '10, that was roughly 1.4 million. So there's a $300,000 increase there, and that's associated with an increase in the number of trainees that we're carrying, and I can give you those number of individuals.

MR. FULTON: Q: Yes, thank you.

MR. O'RILEY: A: As well as the associated expenses.

The second bucket is what we call our early replacement program. So as we have a large -- relatively large number of people, with -- facing retirement in our organization, and we're trying to have a bit of overlap. So traditionally we've waited until the person was gone before we would hire their replacement, and we're trying to have a bit of overlap. So that was not funded. There is about 74 -- 740,000 in fiscal '09 and that drops to 650,000 in fiscal '10, just the way the numbers worked out.

And the training budget, which is the third bucket, and that's really to reflect the fact that we've added, in pursuit of our capital plan -- largely in pursuit of our capital plan, between the beginning of fiscal '07 and August -- you know, pick an August cut-off date, about 430 employees in the EARG group, and these are -- when I talk about employees, I talk about head count. So we've added that many employees. We have over 500 employees that have been with B.C. Hydro less than two years. So we've increased our training budget to really bring those people up to speed. And that goes from -- we've added 400,000 in this initiative for fiscal '09 and there's 460,000 in fiscal '10.

So when you net it all out, it's roughly a $300,000 increase from fiscal '09 to fiscal '10.

MR. FULTON: Q: Thank you. And would you agree with me that the fiscal 2008 RRA budget does not accommodate the incremental costs of the EARG portion of the labour initiative?

MR. O'RILEY: A: The fiscal '08 budget had a number -- it had a significant budget in it for strategic work force planning, and the figure I have for that on the operating side is 4.05 -- $4.06 million. So that was what we had in our fiscal '08 base, and what we've done is increase the -- we've increased that amount for fiscal '09. And we were not able to accommodate that increase in the base budget.

MR. FULTON: Q: Okay. And the reason you weren't able to accommodate the increase in the base budget is because it won't fit with the formula? Or --

MR. O'RILEY: A: No, the reason is really the large volume of additional work that's being taken on by the organization related to capital, related to our water licence, related to -- you know, additional maintenance and other activities, other pressures on the cost structure. So, we've pursued -- I'll just give you three examples of the productivity measures we were able to pursue in -- from our fiscal '08 budget, and one of them, at a very high level in the course of adding 430 people to our organization, we kept the number of people in our finance, IT and HR groups flat over that two and a half year period. So we've added people who were actually doing the work, engineers, and people on the ground, turning the tools. That's where the increase in the 430 people has been largely.

**Proceeding Time 11:17 a.m. T28**

A second example of a productivity initiative that we've achieved is we've had quite a focus on safety in our organization, and we looked at how we were training our employees. This is particularly the IBW employees in the plants, and we found an opportunity to better target our safety training. So we're using -- rather than training everybody in a site around a particular safety course, we're targeting at the people that are most in need of that training. And we've also developed a program of full courses and short refreshers, so that when the two-year cycle comes up you're not taking everybody back through the full course. And that initiative saved $700,000 for this fiscal year, which we've reallocated to tool time and maintenance.

And a third very personal example for me is when I took over this job from Ms. Farrell in the middle of last year, I mean there were two admins in my office, in my cost centre, and we were able through attrition to get that down to one.

So those are just three examples of things we've done to drive productivity improvements in the organization. And even with those, we were not able to accommodate this increase in the labour strategies budget, hence the need for that to be an initiative.

MR. FULTON: Q: Can any of the operating costs that relate to EARG in the labour strategies initiative, in your view be deferred without impacting the safety, reliability or training?

MR. O'RILEY: A: You're talking about the initiative items?

MR. FULTON: Q: Yes.

MR. O'RILEY: A: I mean, that was very much the debate and the discussion that we had in the course of the budgeting process, which I think Mr. Wong would have described and took several months. And we pushed really hard on all the initiatives, and many of them were deferred, put off to future dates. The ones that we've come up with, we believe are absolutely critical to proceed with today for -- to meet the objectives of the company.

MR. FULTON: Q: Thank you. Can you tell us what portion of the strategies are generation labour strategies, first of all? And perhaps if it's easier, if you could give me the split between the operations and maintenance side of the strategies.

MR. O'RILEY: A: Yes. I'm just thinking of a way to get at that, and I think I can.

It's spread throughout, but if I could -- one way of answering that question is to really -- and this is only a partial answer, is to ask where we've increased the trainees in '09 versus '08. So we've added among the IBW staff we've added -- so overall we've added 34 trainees. Among the IBW staff we've added six. We've added 15 engineers. We've added six management trainees. We've added one technologist, one coordinator of occupational safety and health, and we've added five youth trade hires.

So, the ones that relate to the plants, the operating, would be the six IBW trainees, a portion of the EITs, the engineers, the portion of the 15, a portion of the management trainees, and the COSH, the coordinator of occupational safety and health. And the youth trade hires. All the youth trade hires would have been in the plants.

So that's an imperfect answer to your question.

**Proceeding Time 11:22 a.m. T29**

MR. FULTON: Q: While we're on the topic of imperfection, can you give me a ballpark percentage, then? So --

MR. O'RILEY: A: We probably would need to get to you on that.

MR. FULTON: Q: All right, that would be fine.

MR. O'RILEY: A: Why don't we do that?

**Information Request**

MR. O'RILEY: A: So that's the split, just to clarify, between generation, engineering and aboriginal relations. Is that the split you'd be interested in?

MR. FULTON: Q: Yeah, it's the generation only, and a split between operations and maintenance in the generations.

MR. O'RILEY: A: Okay.

MR. FULTON: Q: Okay. And much as I have had for earlier panels, I do have a question for your panel on full-time equivalents. So, if I could ask that you provide me, either if you can do it verbally now or by way of undertaking, the number of full-time equivalents for -- in the fiscal 2008 RRA, the actual number of full-time equivalents in fiscal 2008, the fiscal 2009 plan, full-time equivalents, and the fiscal 2010 full-time equivalents.

MR. O'RILEY: A: Okay. A number of these figures are given in BCUC 2.171.1. I'm not sure all -- so, we've got the planned FTEs for fiscal '07 through '10. We've got the actual FTEs through fiscal '07 and '08. And then we've got the head count numbers. So I think that might answer your question.

MR. FULTON: Q: Let me -- I'd like to just have a moment.

MR. O'RILEY: A: Okay.

COMMISSIONER MILBOURNE: Could you just clarify that you're answering -- did that IR reference, '09 and '10?

MR. O'RILEY: A: The IR provides the plan numbers for '09 and '10.

COMMISSIONER MILBOURNE: Thank you.

MR. FULTON: Q: Well, perhaps we'll check that at lunchtime and --

MR. O'RILEY: A: Yes.

MR. FULTON: Q: The next topic I have relates to service level agreements with BCTC. And again, the reference in the transcript is to transcript 11, page 1869.

MR. O'RILEY: A: Yes, we have it.

MR. FULTON: Q: Okay. And beginning at line 17, I began a question about the costs of providing services to BCTC under the engineering services agreement, and noted that they were reported in Schedule 3.4 at line 26, and that would be from -- in Exhibit B-22 of 58 million and 61.1 million for fiscals 2009 and 2010 respectively. And in the application at page B -- at page 1-23, B.C. Hydro stated that the costs of providing services to BCTC under the engineering service agreement, being 58 million and 61.1 million in fiscal 2010 and fiscal 2010 respectively, are the appropriate costs to be incurred.

And so B.C. Hydro maintains that position then, that they are the appropriate costs to be incurred?

**Proceeding Time 11:27 a.m. T30**

MR. O'RILEY: A: Yes.

MR. FULTON: Q: And those are the numbers, the 58 million and the 61.1 million.

MR. O'RILEY: A: Yes.

MR. FULTON: Q: Yes. Thank you.

Next topic is capital additions. This is also referenced in transcript 11. And I had asked

whether --
MR. O'RILEY: A: Sorry, do you have the reference to the transcript?
MR. FULTON: Q: Yeah, and I'm just looking. I seem to have lost my transcript reference in it, but what the question related to was the year-to-date status of the capital additions compared to the plan in the fiscal 2009 update. So if you were to look at page -- at Exhibit B-22, Appendix 1, Schedule 13, page 38, Mr. Rodford's --
MR. O'RILEY: A: Excuse me, sorry, I'm a little slow. Appendix 1, page 38?
MR. FULTON: Q: Yes. Schedule 13.
MR. O'RILEY: A: I have it.
MR. FULTON: Q: So there's a -- that is a schedule of capital expenditures and additions, and I did ask Mr. Rodford some questions on this and he spoke to field operations. And so I'd like to learn from you what the status is of the capital additions for the areas that this panel is responsible for, for fiscal 2009 compared to the plan.
MR. O'RILEY: A: Okay, and Mr. Eldridge can provide those figures.
MR. FULTON: Q: Thank you.
MR. ELDRIDGE: A: We'll start with the most significant line item, which is the hydro. We don't do a detailed

plan of additions through the year. We detail the significant assets and when they're expected to go in service. The remainder of our assets we do on an expected basis, based on past history. So on that basis, the expected in-service amounts up to August, which is the most recent information I have, is 135 million. And our actual additions, again to August 2008, were 137 million in additions. So basically we're on plan in terms of additions.

And I can speak to what some of those amounts are if it would be of use.

MR. FULTON: Q: No, I think that's fine. So the Hydro one though, am I comparing the 138 to the 308?

MR. ELDRIDGE: A: Correct.

MR. FULTON: Q: Okay. And so then going down to the other line items that are the responsibility of this panel, can you tell us where you are on those, for capital additions? So I'm assuming that line item 14 for example.

MR. ELDRIDGE: A: Line items 14, general thermal. I'm afraid I don't have the detailed additions for that line item. So the total for the year would be 12.6 million. So to this point we would expect around 5 million and unfortunately I don't have -- oh, actually no, pardon me, I do have that amount here. So the expectation to this point in the year, again using an assumption that five-twelfths of that amount would be the plan to August, our additions for the full year was 13 million. That prorated 5 over 12 would be approximately between 5 and 6 million, and we've pulled out approximately a million in service in thermal.

**Proceeding Time 11:32 a.m. T31**

MR. FULTON: Q: Okay, so the million dollars is the actual amount to the end of August.

MR. ELDRIDGE: A: That is actual amount to August, yes.

MR. FULTON: Q: Okay.

MR. O'RILEY: A: And if you look at the individual projects --

MR. ELDRIDGE: A: Oh, actually I apologize, I was picking up the wrong number. The total thermal additions to August was 8.6. The .8 I mentioned are smaller projects under a half million. There are other more significant projects that relate to -- almost solely to Burrard generating station. So the total additions to August is 8.6, and the plan for the entire year is 12.6, for thermal.

MR. FULTON: Q: All right.

MR. ELDRIDGE: A: And I believe earlier I referenced a number of 13.3? That was the diesel line. If I go one line down, I see that 12.6.

MR. FULTON: Q: Yes.

MR. ELDRIDGE: A: So in case I was confusing anyone, I apologize.
MR. FULTON: Q: Yes, and Panel 5 dealt with the diesel numbers.
MR. ELDRIDGE: A: Right.
MR. FULTON: Q: So, what other line items, then, under total capital additions, is this panel responsible for?
MR. ELDRIDGE: A: Line 20, there's an amount of information technology for EARG.
MR. FULTON: Q: Yes.
MR. ELDRIDGE: A: We have amounts in service of .2 million, and the target for the full year is 2.7 for fiscal '09.
MR. FULTON: Q: So is that a timing difference, or are you expecting to hit the 2.7 in fiscal 2009?
MR. ELDRIDGE: A: It is a matter of timing, but I think we are at risk, given that we're so significantly behind year-to-date, that we won't achieve that 2.7 for the IT.
MR. FULTON: Q: Okay, so how much do you expect, then, that you will achieve for IT?
MR. ELDRIDGE: A: I'm afraid we haven't looked at that, the details of that line item in particular.
MR. FULTON: Q: Okay.
MR. ELDRIDGE: A: We've looked at the hydro and the

thermal more, just because they are more significant items.
MR. FULTON: Q: Right. Okay. Other line items? Property and others?
MR. ELDRIDGE: A: There is a very small amount of .2 million -- or of 200,000, and I'm afraid I don't have any details on that.
MR. FULTON: Q: All right. Then if we go to the expenditures, can you -- at the top of the page, can you tell us where EARG is in terms of actual expenditures compared to the expenditures listed in the fiscal 2009 update?
MR. O'RILEY: A: I can speak to that. The EARG expenditures, if you add up the different numbers for the plan, should add up to 386 million, and these numbers are to the end of September, which I just pulled off before we started this, and we're halfway through. We're at 183.7, which is roughly where we'd expect to be six months into the year.
MR. FULTON: Q: Okay.
MR. O'RILEY: A: So we're on track to achieving our expenditures this year.
MR. FULTON: Q: All right, thank you. Next questions relate to load curtailment, and I believe that you're the person on this one, Ms. Kurschner. And Volume 6 of the transcript, page 917, I was having a discussion

with Mr. Wong in terms of load curtailment, and the discussion actually began on the previous page at line 7.
MR. ELDRIDGE: A: One moment. Was it 917?
MR. FULTON: Q: Yes.
MS. KURSCHNER: A: Oh, 917. Okay.
MR. ELDRIDGE: A: We had 971.
MS. KURSCHNER: A: I have that.
MR. FULTON: Q: Okay. And to put the discussion in context that I had with Mr. Wong, I was referencing page 3-12 of Exhibit B-1, which has Table 3-2.
MS. KURSCHNER: A: That's in the original application?
MR. FULTON: Q: Yes, it is.
MS. KURSCHNER: A: Table 3-2 --
MR. FULTON: Q: Yes.
MS. KURSCHNER: A: -- on load curtailment? Yes, I've got that.

**Proceeding Time 9:05 a.m. T2**

MR. FULTON: Q: Okay. And I asked Mr. Wong at page 917 what percentage of the contracts were fixed cost contracts, and which percentage were evergreen. He wasn't familiar with the details related to those contracts and he referred me to this panel.
So can you help us out, Ms. Kurschner?
MS. KURSCHNER: A: So for fiscal '09 --
MR. FULTON: Q: Yes.

MS. KURSCHNER: A: -- we have a total of -- currently, which if you recall yesterday I was talking about the evergreen, some of the evergreen contracts being extended or not terminated, renewed I guess is the word --

MR. FULTON: Q: Yes.

MS. KURSCHNER: A: -- in June. So as of now, we have a total of 404.5 megawatts. Out of that, 101 megawatts for fiscal '09 are evergreen, and that leaves 303.5 megawatts for a fixed term.

MR. FULTON: Q: Okay.

MS. KURSCHNER: A: Or fixed contract.

MR. FULTON: Q: And for fiscal 2010?

MS. KURSCHNER: A: And for fiscal '10, right now we're still -- would consider the evergreen zero because there is the termination clause and renewal clause for next June. And we do -- so the number stays as it was in that Table 3.2 at the fixed 256.5 megawatts.

MR. FULTON: Q: Thank you. And then dropping down on transcript page 917, I had asked -- and actually specifically beginning at line 19 of 917, that as notice to Mr. O'Riley in this panel,

> "…I would like to know the minimum, maximum and expected amounts for each year for those contracts that are referred to as fixed contracts in Table 3-2."

So are you able to provide us with that information?
MS. KURSCHNER: A: Can you explain to me what you meant by minimum, maximum and expected amounts? Are you referring to the energy associated with those contracts that we might call on?
MR. FULTON: Q: Okay. Well, let me ask you this. Are the amounts for variable costs shown for fiscal 2009-2010, the maximum or minimum or expected amounts?
MS. KURSCHNER: A: They're the maximum.
MR. FULTON: Q: Okay.
MS. KURSCHNER: A: And you just have to remember that Table 3.2 only had the energy associated with the fixed contracts.
MR. FULTON: Q: Okay. And does B.C. Hydro have expected amounts?
MS. KURSCHNER: A: No.
MR. FULTON: Q: For those contracts?
MS. KURSCHNER: A: No, and that's what I was trying to explain yesterday. It really depends largely on the particular situation that will develop on the type of winter that we will have. But it was designed around the criteria of serving us through the cold snap.
MR. FULTON: Q: Okay, thank you. If I can take you back to yesterday's evidence at page 2057 of the transcript, and beginning at line 24 you were continuing discussion with Mr. Wallace about load

curtailment, Ms. Kurschner, and then following over onto the next page and down to line 5, you spoke about that you can only call on the load curtailment roughly on average 15 times a venture and for four hours at a time.
MS. KURSCHNER: A: Apparently I cannot pronounce "winter".
MR. FULTON: Q: Okay. Thank you for that clarification.
MS. KURSCHNER: A: But it is a good venture.
MR. FULTON: Q: I had taken that as meaning customer rather than winter, so --

**Proceeding Time 11:42 a.m. T33**

MR. FULTON: Q: Okay. Can you tell us, though, what the expected number of times a load curtailment customer will be interrupted for four hours at a time in the year? You've told us what the average is, but what is the expected number of times?
MS. KURSCHNER: A: No, I didn't say what the average is. I said that 15 was the maximum allowed under the contract.
MR. FULTON: Q: Okay.
MS. KURSCHNER: A: And again, I do not have an expected number.
MR. O'RILEY: A: The average here, I think, referred to the different customers that we'd contracted.

MS. KURSCHNER: A: Oh, right.
MR. O'RILEY: A: So --
MS. KURSCHNER: A: Yes.
MR. O'RILEY: A: That's the maximum amount for them.
MS. KURSCHNER: A: Okay.
MR. O'RILEY: A: We have one customer that only wanted us -- that wanted a smaller number of interruptions, so it's not constant through the population.
MR. FULTON: Q: Now, with one of the other utilities, as I recollect evidence from previous proceedings, they don't interrupt very often in terms of curtailing. Are you able to provide us with information as to how often those customers would have been interrupted in tabular format? Not identifying the customers, but just saying how often the customers would have been interrupted in the last year.
MS. KURSCHNER: A: Last year --
MR. CHRISTIAN: Did I hear the question in reference to another utility? I'm sorry.
MR. FULTON: Q: Yeah. What I've said is that, and what I intended to say, was that my recollection from evidence of another utility is that they don't interrupt very often if at all, even though they've got load curtailment provisions in their contracts. So what I want to do from this panel is to get some sense as to what the reality is of the interruptions

in terms of numbers.
MR. CHRISTIAN: For B.C. Hydro.
MR. FULTON: For B.C. Hydro, yes.
MS. KURSCHNER: A: So, last year we did not call energy out of any of the load curtailment contracts. I do want to emphasize, though, that doesn't mean they're not used. And if you recall, there was that long conversation about the load curtailment contracts are used pretty much throughout the winter, as a capacity on standby.
So last year I was describing, we had a very -- we had a winter that, on average, which was below normal in temperature, but we had no severe cold. So we had very low peaks, and we got through the winter without any dramatic capacity shortages. The year before, when we had voluntary curtailment contracts in place, we did exercise a few times around, I believe, one of the days that we exercised was on 28th of November, just the day before we reached the peak.
MR. FULTON: Q: Okay. All right, thank you.
MS. KURSCHNER: A: And just maybe -- there is a difference, and I do not know any particulars of any other utilities, but there are tariffs that have load curtailment in the supply contract. But this is very different. These are targeted load curtailment

contracts. So it is quite different from a tariff rate that might allow curtailment in it.
MR. FULTON: Q: All right. Thank you, that's helpful. I did want to see how many -- or know how many times that there had been interruptions in the past year, and you've given me that answer, and you've also provided us with some evidence on the previous year to that too, so thank you for that.
Returning to Volume 6 of the transcript, and the topic I want to talk about next is the engineering -- the BCTC service agreement audit and the engineering audit for the first quarter of 2007. And I first raise this issue at page 1001 of the transcript beginning at line 17, and Mr. Webb directed me to Panel 6 for my questions in this area.

**Proceeding Time 11:46 a.m. T34**

MR. O'RILEY: A: So page 1001?
MR. FULTON: Q: Yes, line 17.
MR. O'RILEY: A: Yes, at the bottom. I see that.
MR. FULTON: Q: Over to 1002, line 6. So if I could ask you to have before you Exhibit B8-1, and the responses to BCUC IRs 2.177.1 and 2.177.2. And if we begin --
MR. O'RILEY: A: Sorry, I have 2.177.1 and 2, and what is the other?
MR. FULTON: Q: 177.2.

MR. O'RILEY: A: Okay. Yes, we have those.
MR. FULTON: Q: So that in 2.177.1, Commission Staff asked for a copy of the documentation review and approval procedure and policy developed from the completed discussion with BCTC. And then in 2.177.2, Staff asked B.C. Hydro to provide a copy of the findings by EARG Finance that develop a process to identify revenues under Article 8.3(a).
And just before I continue on with these questions, would you agree with me that B.C. Hydro management had agreed with the recommendations in the BCTC audit report? And if you need a reference for that, it's Exhibit B5-1, BCUC IR 1.8.1, Attachment 29, page 3.
MR. O'RILEY: A: Yeah, I believe we did.
MR. FULTON: Q: Okay. And is B.C. Hydro still in agreement with the audit report's recommendations and management action plans, Mr. O'Riley?
MR. O'RILEY: A: I believe so. I have no reason to believe we're not.
MR. FULTON: Q: In the response to 2.177.1, a changed notice report was referenced. Can you provide by way of undertaking a sample copy of the changed notice report?
MR. CHRISTIAN: Yeah, we can do that.

**Information Request**

MR. FULTON: Q: And in terms of the question itself, "Provide a copy of the documentation review and approval procedure and policy developed," does that information exist, that documentation exist?
MR. O'RILEY: A: Well, I think the way -- I think what this response articulates is that the -- I think the result of this was to produce the report, like to produce the format for the report that was subsequently used. I'm not sure there's another document which documents the process. I'm not aware of another document.

**Proceeding Time 11:51 a.m. T35**

MR. FULTON: Q: All right, thank you. Has B.C. Hydro satisfied now, the audit requirement for a project documentation completeness and audit trails?
MR. O'RILEY: A: I believe we have. That's signified by the complete and the follow-up.
MR. FULTON: Q: Okay.
MR. O'RILEY: A: And in our organization that would be overseen by the Finance group, to ensure that that audit obligation was met.
MR. FULTON: Q: Okay.
MR. ELDRIDGE: A: And I might add, to the extent that our audit report says "complete", our internal audit group would have verified that we would have satisfied their issue. So just by virtue of it saying

"complete" it means that we've dealt with it or addressed it.
MR. FULTON: Q: Okay. And next is the Site C regulatory account, and this was referred -- my questions here were referred to this panel, again by Mr. Webb at page 995 of transcript Volume 6.
MR. O'RILEY: A: I will take those questions.
MR. FULTON: Q: Okay. And probably also want to have before you then Exhibit B5-1, the response to BCUC IR 1.65.2.
MR. O'RILEY: A: I have both documents.
MR. FULTON: Q: And in that response, B.C. Hydro noted the uncertainty of costs related to Stage 3 of the project and said it would not be appropriate to limit the approval of the Site C regulatory account expenditures by total dollar amount.
Can you tell us whether the Stage 3 costs are at present expected to be higher or lower in their effect at the end of fiscal 2010? So the costs in this --
MR. O'RILEY: A: I'm not sure I understand your question.
MR. FULTON: Q: So that the Stage 3 costs that we will see in the regulatory -- the Site C regulatory account at the end of fiscal 2010, are you anticipating them to be higher or lower than -- at this time? Because

you've said that it wouldn't be appropriate to limit the approval of the Site C regulatory account expenditures by dollar amount. So --

MR. O'RILEY: A: Yeah. And I think that really speaks to the uncertainty in Stage 3. So we're in the latter -- well, probably say we're in the midst of Stage 2 and we've not done detailed planning on Stage 3. And the nature of Stage 3 will depend to a great extent on the impact -- input of stakeholders and First Nations through this process and the analysis of that input, as well as decisions by the province about how Stage 3 will unfold. There's also quite a bit of uncertainty about the duration of these stages, as we've seen from Stage 1 and Stage 2, and that's a significant driver of the cost uncertainty.

So we do not have a good estimate now of Stage 3 costs.

MR. FULTON: Q: Okay. Do you have any estimate?

MR. O'RILEY: A: Well, I think we published a previous estimate. Let's see if I can find that.

I'm going to struggle to find that off the -- I believe there's been one published. Certainly in the previous IEP there was a Stage 3 estimate, and I believe there's an estimate in the documentation but I can't put my finger on it right this moment.

MR. FULTON: Q: All right, thank you. Well, if you

locate it you can provide it to your counsel and provide it on the record by way of undertaking.
MR. O'RILEY: A: Okay.
MR. FULTON: Q: Thank you.
MR. CHRISTIAN: Well, if it's on the record already I'll just speak to it. I don't expect I'll file another undertaking.
MR. FULTON: Q: Yes, that's fine, thank you.
Just one last question before we break. This morning

**Proceeding Time 11:56 a.m. T36**

MR. FULTON: Q: Yes, that's fine, thank you.
Just one last question before we break. This morning we received Exhibit B-72, and that response was completely responsive to my -- the question that I asked at Volume 9, page 1540 of the transcript. That is the on-line instructions with respect to expender and authorization requests, EARs.
In looking at that Exhibit B-72, the page 1 of 24 references in the second box other supporting documentation, and there's an EAR form in Excel and an EAR form in Word. Could I ask you to file those forms as well, please?
MR. CHRISTIAN: To the extent it's not already in this 24-page document then, yes, we'll file it.

**Information Request**

MR. FULTON: Q: And then the last request that I have relative to EAR is, can you provide an example of a completed and approved EAR form? We've had some discussions about the Coquitlam dam. That could be an example, or you could give another example just so that we see what a completed form looks like?
MR. O'RILEY: A: I would suggest the Coquitlam year, since we've already provided it and it's a pretty good example, so --
MR. FULTON: Q: All right. So is that EAR in the material that was provided to the Commission --
MR. O'RILEY: A: Yes.
MR. FULTON: Q: -- Panel as part of the briefing materials?
MR. O'RILEY: A: Yes. And the EAR would look like a form -- well, it's a several-page form that's filled out electronically, and attached to that is some cash-flow sheets and then a business case, and we think of the package as the EAR.
MR. FULTON: Q: All right. Thank you.
Thank you, Madam Chair, this would be a good time to take the morning -- or the lunch breach.
THE CHAIRPERSON: Thank you very much. We shall resume 1:30.
**(PROCEEDINGS ADJOURNED AT 11:58 A.M.)**
**(PROCEEDINGS RESUMED AT 1:33 P.M.)** **T37/38**

THE CHAIRPERSON: Please be seated.
Mr. Fulton, you are ready to continue?
MR. FULTON: I am, thank you, Madam Chair.
MR. FULTON: Q: Mr. O'Riley, thank you for the reference to BCUC IR 2.71.1. I don't need to ask any more questions on FTEs.
MR. O'RILEY: A: Thank you.
MR. FULTON: Q: And I'm finished with my references to the transcript at this point, so you don't need to have the transcripts before you any longer, either.
I'd like to next turn to B.C. Hydro's working relationship with FortisBC, and so if you could turn to Exhibit B8-1, BCUC IR 2.169.3. And --
MR. O'RILEY: A: Excuse me, we're just -- one moment.
MR. FULTON: Q: Thank you. 2.169.3.
MR. O'RILEY: A: Yes, we have it.
MR. FULTON: Q: Okay. And do I take it from the second paragraph of that answer that B.C. Hydro limits its charges to Fortis to labour cost recovery?
MR. O'RILEY: A: I believe what this is saying is that for Fortis and BCTC, we're giving them a price based on fully allocated internal costs for engineering services. And in the case of Fortis, we're adding a profit margin in addition to that.
MR. FULTON: Q: Okay. Because as I read the answer, BCTC and Fortis are the exceptions, and then B.C.

Hydro charges the other companies the greater of market rates or fully allocated internal costs for engineering services. So, as I took the answer, FortisBC and BCTC were getting a better deal than the other companies. Am I --
MR. O'RILEY: A: That is correct.

**Proceeding Time 1:35 p.m. T39**

MR. FULTON: Q: Okay. And I take it that B.C. Hydro has contractual obligations to Fortis to provide labour services, and I'm thinking in particular, for example, on the OTR.
MR. O'RILEY: A: Yes.
MR. FULTON: Q: And does the work that B.C. Hydro provides to Fortis, for example, result in overtime for B.C. Hydro IBEW employees and engineers?
MR. O'RILEY: A: There is no involvement of IBW employees in these contracts -- no B.C. Hydro IBW employees. There may be other companies employed involved. But our employees, our IBW employees are not involved.
There may be some overtime incurred by B.C. Hydro engineering staff in the course of doing this work, and there is an allowance in the pricing for overtime.
MR. FULTON: Q: Okay. So B.C. Hydro then is kept whole in terms of --

MR. O'RILEY: A: We believe they are, and there's actually a profit built into the agreement.

MR. FULTON: Q: Okay. So B.C. Hydro then is kept whole in terms of that.

MR. O'RILEY: A: We believe they are, and there's actually a profit built into the agreement.

MR. FULTON: Q: Okay. And do I take it then that, you know, notwithstanding the comments that you've made about the need to find new skilled people and what's happened in terms of the labour initiatives, you're able to provide engineering staff, for example, to provide services under these contracts without compromising B.C. Hydro projects?

MR. O'RILEY: A: We believe yes. These are a relatively small part of our business, and the intent is that they remain small. We're not in the business of looking for additional engineering consulting work. We don't see ourselves as an engineering consulting firm. We do anticipate taking on this work very very occasionally, and really the attractiveness for me for this work is that it can be good development for our employees. So we've done two jobs with Fortis, this current OTR and then the Vaseux Lake job. And the Vaseux Lake job provided some very good 500 kV experience that we hadn't got in our own company, into our own work in a number of years, so it was a really good development opportunity. I'm not looking for any -- in general we're not looking for opportunities to add this to our business.

**Proceeding Time 1:38 p.m. T40**

MR. FULTON: Q: Okay. All right, so I'd like to just ask some general questions about what happens under the contract with Fortis on the OTR.

Don't answer the questions until your counsel has an opportunity to say whether he objects to the question on the basis that there are confidentiality concerns. I'm hoping that they will be general enough that you won't need to concern yourself about that.

MR. O'RILEY: A: Okay.

MR. FULTON: Q: But wait until you get the nod before answering.

MR. O'RILEY: A: Oh, always, I think is the --

MR. CHRISTIAN: I think that's the first time I've been invited to make (inaudible).

MR. FULTON: Q: Under the -- are you the one in particular who would have general knowledge of the OTR contract on this panel? Or is there someone better to answer those questions?

MR. O'RILEY: A: I would have the general knowledge. We probably could test the depths of that knowledge very quickly, but I am the best position on this panel

to do that.
MR. FULTON: Q: And what I want to try and determine is the exposure of B.C. Hydro ratepayers if things don't go as B.C. Hydro would wish under the terms of the OTR contract. So, under the contract, I would assume that if there are problems with the type of work that B.C. Hydro is providing, B.C. Hydro has to remedy those effects, or problems.
MR. O'RILEY: A: There is insurance we hold, and we've acquired, for, like professional liability insurance. So those kind of issues are dealt with, and that's costed into the bid.
MR. FULTON: Q: Okay. And does that insurance cover cost over-runs as well, for example?
MR. O'RILEY: A: Cost over-runs are not the responsibility of B.C. Hydro. Those costs flow back to Fortis.
MR. FULTON: Q: Okay. And in the event, for example, that an action is commenced by a -- well, we'll start with a third party, arising out of the work that B.C. Hydro has done. That is going to be covered by the insurance, I take it, that you spoke about?
MR. O'RILEY: A: If it was an action related to a professional liability of B.C. Hydro.

**Proceeding Time 1:41 p.m. T41**

MR. FULTON: Q: Okay. In terms of prioritizing the work that B.C. Hydro has for its projects, and the work that it might do for Fortis or BCTC, how does B.C. Hydro prioritize that?

MR. O'RILEY: A: The expertise for the three different components of our engineering group, the distribution, the transmission and the generation, are largely independent. So, we're not moving people back and forth between a generation project and a transmission project and a distribution project. That happens very rarely. The one opportunity where that might happen is in more of a general area, like project management. That's happened in the past. We've moved people back and forth. But that would again be the exception.

So, for the purpose of your question, it's really how are we allocating between our transmission engineering expertise between BCTC and Fortis work, and again, our view is that this is a very modest amount of work, and BCTC is our prime customer. And our intent is to serve that work and not let any -- serve that customer and not let anything get in the way of that work. We don't believe that this Fortis contract is causing any problems on our ability to deliver with BCTC.

MR. FULTON: Q: Okay. And just looking back at the response to 2.169.3, FortisBC does get a price break relative to other companies, in terms of market rates and fully allocated internal costs for engineering services, correct?

MR. O'RILEY: A: Yes.

MR. FULTON: Q: Okay. And can you tell us what the policy reason is for giving Fortis that price break?

MR. O'RILEY: A: The -- excuse me for one second.

Okay. I can answer that question. This policy of charging the greater of market rates or fully allocated internal costs for engineering services, except for Fortis and BCTC, was developed fairly recently, I believe in the summer. Really to give some guidance to managers who are making these kind of decisions. And generally they came up very rarely.

**Proceeding Time 1:44 p.m. T42**

And an example where they come up would be where we're asked to provide an individual expert to participate on an advisory board or such. A fairly modest undertaking. Limited amount of time and such. So we would apply this policy the greater of market and internal costs.

Prior to developing that policy, we'd entered into this agreement with Fortis, and that was done as a one-off or individual case, and we built up the bid, if you will, based on our internal rates with the various loadings that are applied. And then in addition to that, at the contract level we added in a profit margin. So we feel like -- we feel very strongly that the Fortis contract allows us to more than cover our costs for this type of work, but we're not prepared to go and enter into that type of contract with many many other suppliers, simply because that's not our business.

MR. FULTON: Q: Okay. But going forward then, is it expected that Fortis will fall within the category of the other companies in terms of what they're charged?

MR. O'RILEY: A: Well, I think for future business with Fortis, we'd have to look at it. Again, our primary responsibility is to serve BCTC, and we would have to consider whether we have the capacity to take on any future work from Fortis. We'd also have to look at the risk profile of the transaction. I think any large deal would have to be looked at on a one-of basis. So I think really the policy distinction is we're distinguishing between large projects that we take on for BCTC and Fortis, and the one-off smaller engagements that we might, inevitably through the course of our work, take on for other third parties, recognizing that in aggregate that other category would be small.

MR. FULTON: Q: Okay. And in the response when it referred to the exception for BCTC and FortisBC, we've

spoken about the OTR contract. Did the Vaseux Lake
contract also fall within the exception?
MR. O'RILEY: A: Well, the Vaseux Lake contract was
done -- actually, no, it was done some time ago. And
again, that pricing was built up on a one-of basis. I
think the model, and I don't have direct experience
with the Vaseux Lake contract, I think the model was
very similar to what we followed with the OTR
contract.
MR. FULTON: Q: I'd now like to turn to First Nations,
and Mr. Viereck, give you an opportunity at this
point.
MR. VIERECK: A: Oh, thank you.
MR. FULTON: Q: And I just have a few questions on
First Nations. Exhibit B-1, section 1.2.2.6 at page
1.9, speaks of the First Nations and there in summary
-- I'll wait till it's passed over to you. So that's
page 1-9 of the application.

**Proceeding Time 1:47 p.m. T43**

MR. VIERECK: A: Yes, I have it in front of me.
MR. FULTON: Q: There, in summary form, it's stated
that B.C. Hydro recognizes that strong long-term
relationships with First Nations communities are
imperative to B.C. Hydro's ability to deliver electric
services now and in the future. And can you tell us,
first of all, whether any of the First Nations costs

were included in the 2008 RRA?
MR. VIERECK: A: First Nation costs?
MR. FULTON: Q: Yes.
MR. VIERECK: A: As in the operating budgets of --
MR. FULTON: Q: Yes.
MR. VIERECK: A: Yes, I believe they were.
MR. FULTON: Q: Yes. And any of the initiative -- the costs that form part of the ongoing and fixed operating initiatives? And maybe if I can take you to the page so that you'll see what I'm talking about. If you turn to Table 4-2 at page 4-16 of the application.
MR. VIERECK: A: Yeah, I have that in front of me.
MR. FULTON: Q: Okay. All right. So, there are costs of 5.7 and 7.2 million for ongoing First Nations initiatives. Were any of those costs included in the 2008 RRA, fiscal 2008 RRA?
MR. VIERECK: A: Just a moment.
MR. FULTON: Q: Thank you.
MR. VIERECK: A: My apologies. Those costs were not in the base in F08.

**Proceeding Time 1:53 p.m. T44**

MR. FULTON: Q: And would you agree with me that the First Nations costs that appear on Table 4-2 are not accommodated within the existing budget as determined by the formula?

MR. ELDRIDGE: A: It might be useful to speak about some of the breakdown of the activities. But the base budget we had in fiscal '08 didn't include any of these incremental amounts for the different elements of the initiative. And I don't know if it would be useful to you to speak about those individual components. But in total, the '09 amounts are fully incremental to what we would have had in fiscal '08.
MR. FULTON: Q: Okay. In terms of these incremental costs though, perhaps you can tell us why they can't be accommodated by the formula? Can you do that, Mr. Eldridge or Mr. Viereck?
MR. VIERECK: A: I can certainly explain to you what the costs are and why they're incremental to the base.
MR. FULTON: Q: Okay.
MR. VIERECK: A: So in terms of the breakdown of the costs, we have a program which is the Williston Dust Program, that is the result of a series of studies on the impacts of dust in the Williston Reservoir. And the reason that dust is created in the Williston Reservoir was the result of the reservoir being created and the continuous lowering and raising of that reservoir that over time had created significant mud flats and areas that, at low pool, dried out over the summer, creating tremendous dust storms. And there are two First Nation villages located at the

north end of that reservoir, and there was significant concern about the health impacts of that, of the dust storms. And there had been a number of attempts to remedy that problem over the years.

It resulted in a series of experts from around the world coming in and taking a look at the dust issue, and they recommended the number of steps that could be undertaken to significantly mitigate the impact of dust. And so that program was put into place, and those are the incremental costs for that.

With respect --

MR. FULTON: Q: Can I just stop you there? Can you tell me what the amount of those costs are for fiscal 2009 and fiscal 2010?

MR. VIERECK: A: The costs that are in the EARG operating budget are 2 million in F09 and 3.2 million in F10.

MR. FULTON: Q: Okay, thank you.

MR. O'RILEY: A: And I can just add, the amount that we had in previous budgets, and we've been spending consistently to mitigate dust, has been $150,000, and that was netted off the amount that went in the initiative. And our concern with spending that amount of money is that it was completely ineffectual and essentially doing nothing. So that was what triggered the -- the recognition of that was what triggered this contracting of these experts to come in and say, "How would you solve this problem once and for all?"

So the idea of what we had in the budget was completely inadequate to actually address the impacts we were imposing on these two communities at the far end of Finlay Reach.

MR. FULTON: Q: Thank you.

**Proceeding Time 1:57 p.m. T45**

MR. VIERECK: A: The second area in terms of the Williston implementation, that refers to a set of negotiations that Hydro has undertaken since 2002, it's the result of litigation filed by First Nations in 1999 and 2001, and there has been a public announcement about an agreement in principle reached with the two First Nations, and one of the keys in terms of First Nation agreements, and this is being demonstrated not only in British Columbia but in Canada, is that you have to ensure that you have adequate funding for implementation, not only to meet the legal obligations that are in the agreement on an ongoing basis, but also it has been found that unsuccessful implementation has in fact resulted in significantly higher future costs. So this is an investment to ensure that we not only meet the legal obligations but also continue to build an effective relationship with the First Nation.

The community development fund is a result, again, of a program and a court case where First Nations had attempted to tax B.C. Hydro for its assets that are on reserves. And as a result of comments of the court, B.C. Hydro established a program that provided payments to First Nations for our transmission and distribution assets that are located on aboriginal reserves. And that was established a number of years ago. The result of it is that our expansion in terms of the transmission and distribution assets that are located on reserves have taken us up to the cap that was established by Treasury Board of $1.6 million.

This program funding is intended to allow for us to recognize those additional assets -- new assets that are in place.

MR. FULTON: Q: So in terms of the amount allocated to that fund for the two years?

MR. VIERECK: A: The additional dollars is half a million in F09 and .7 million in F10.

The Heritage conservation fund, or funding that's related to the *Heritage Conservation Act*, that is a program that is being implemented to deal with and to address non-compliance of issues of B.C. Hydro regarding our reservoirs and the *Heritage Conservation Act*. And what has happened is that the Heritage archaeological branch has indicated that B.C. Hydro is currently not in compliance with the *Heritage Conservation Act*, and that they have asked us to conduct a series of studies on our reservoirs across the province with regards to archaeological assets that may exist there, and then to determine what steps would be taken by B.C. Hydro to protect those assets.

MR. FULTON: Q: If I can maybe help you along, if you turn to BCUC IR 1.50.4, Exhibit B5-1, that's a table that provides the activity and resource breakdown of the base and incremental First Nations operating costs for fiscal 2009 and 2010.

MR. VIERECK: A: Yeah.

MR. FULTON: Q: Okay. And so we've dealt with the Williston dust mitigation.

**Proceeding Time 2:02 p.m. T46**

MR. VIERECK: A: Right.

MR. FULTON: Q: The second one was the Williston agreement implementation. Correct?

MR. VIERECK: A: That is correct.

MR. FULTON: Q: The Community Development Fund, we've dealt with. Now, is the Heritage Fund part of the ARN capital project implementation?

MR. O'RILEY: A: It's on the next page.

MR. FULTON: Q: Okay.

MR. O'RILEY: A: The second page.

MR. FULTON: Q: Okay, thank you.
MR. O'RILEY: A: The issue with the *Heritage Conservation Act* is -- with respect to the reservoirs, is there are Heritage -- there are archaeological sites within the reservoirs, and every time you de-water those sites you actually cause a bit of damage to them. So the risk with this new Act is that there could be constraints on our ability to draft the reservoirs from an operational perspective if we're not doing this work. So it's actually very critical work in terms of supporting our operations.
MR. FULTON: Q: Thank you. Thank you, Mr. Viereck.
Mr. Dunlop, to you next, and NERC. And Mr. Austin asked you a number of questions on NERC this morning, and I just had a follow-up on those questions. His point of context for you was Exhibit B-1, page 4-19.
MR. DUNLOP: A: Yes.
MR. FULTON: Q: And you mentioned that it was anticipated that BCTC would file its report sometime early in the new year?
MR. DUNLOP: A: Yes, that's -- yes.
MR. FULTON: Q: And is B.C. Hydro expecting a decision from the Commission on the BCTC application prior to the end of fiscal 2009, so prior to March 31st, 2009?
MR. DUNLOP: A: I'm not sure that we anticipated a date

for a decision, but we did believe that it was necessary to prepare for implementation of some form of mandatory reliability standards as indicated in the 2007 Energy Plan.

MR. FULTON: Q: And at page 4-20, lines 7 to 10, there's a reference to the costs of 1.2 million in fiscal 2009 and .9 million in fiscal 2010. Mr. Austin said he thought that the updated figures changed that somewhat but not by a larger amount. When I looked at Exhibit B-22, which is the October update, it seemed to me that the amounts had remained -- the amounts have remained the same.

MR. DUNLOP: A: That's my understanding, yes.

MR. FULTON: Q: Yes, and so that schedule 5, page 18, line 11 of Exhibit B-22.

Has B.C. Hydro begun to expend, in this fiscal year, the $1.2 million?

MR. DUNLOP: A: We have developed a project plan and anticipate hiring a program manager by the end of November.

MR. FULTON: Q: So does B.C. Hydro then expect to expend the 1.2 million by the end of March?

MR. DUNLOP: A: No, our current year-end forecast is 350 to $500,000.

MR. FULTON: Q: Okay. And do I take it then that the balance will be then expended, or it's anticipated that the balance will be expended in fiscal 2010.

**Proceeding Time 2:07 p.m. T47**

MR. DUNLOP: A: The amount will, I expect, need to be carried over to a future year. I don't -- I can't say whether the additional amount will be expended in fiscal '10.

MR. FULTON: Q: Okay. And would you also expect, then, that the .9 million that's presently in the budget for fiscal 2010 would be carried over into fiscal 2011?

MR. DUNLOP: A: I would expect the spending in fiscal 2010 to be the $900,000. And that is what we anticipate future spend will be on ensuring compliance with the mandatory reliability standards on an ongoing basis.

MR. FULTON: Q: Right. Were the costs for the NERC compliance initiative included in the fiscal 2008 RRA?

MR. DUNLOP: A: No, they were not.

MR. FULTON: Q: And can you tell us why there is a need to, on the budget -- on the fiscal 2009 plan, why there's a need to expend more in fiscal 2009 rather than fiscal 2010?

MR. DUNLOP: A: I'm sorry, could you repeat the question, please?

MR. FULTON: Q: Let me try it this way. In terms of the NERC compliance initiative, why are the costs front-ended in terms of amounts for fiscal 2009, rather than fiscal 2010? And when I say front-ended, that's probably too broad a term, but you're spending 1.2 million in fiscal 2009 and .9 in 2010.

MR. DUNLOP: A: The additional costs in fiscal 2009 were anticipated to establish the processes that would be necessary to follow in future years, to demonstrate compliance. Also, employee training.

MR. FULTON: Q: Okay. Now, you also indicated to Mr. Austin that there were some 35 of 94 NERC standards that had been approved by FERC and, if adopted by the Utilities Commission, would apply to B.C. Hydro as well. Do you recall that evidence this morning?

MR. DUNLOP: A: Yes.

MR. FULTON: Q: And in terms of those 35 NERC standards, is B.C. Hydro complying with those standards already?

MR. DUNLOP: A: We are complying with some of them to a certain extent, but we are not complying with all of them fully.

MR. FULTON: Q: Okay. So in terms of the rough percentage of how many you would be complying with at this point of the 35?

MR. DUNLOP: A: I think one of the main differences between how I would describe us complying today versus after a mandatory reliability standards are introduced would be in terms of reporting. We currently do very

little compliance reporting, in terms of -- that the
voluntary standards that we're following, but we're
anticipating that if mandatory reliability standards
are introduced, that the compliance reporting becomes
much more significant.
MR. FULTON: Q: But in terms of B.C. Hydro's -- or the
effect that the NERC, the approval of the NERC
standards may have on B.C. Hydro's present reliability
of its system, will compliance enhance that
reliability or is it more as you've said to do with
the reporting requirements?

**Proceeding Time 2:11 p.m. T48**

MR. DUNLOP: A: I don't believe that compliance with
the NERC and WEC standards in themselves will improve
reliability. But compliance with the mandatory
reliability standards, or compliance with some form of
mandatory reliability standards, we believe, will be
necessary to enable us to integrate -- to interconnect
with the U.S. interconnected network.
MR. FULTON: Q: Thank you.
MR. O'RILEY: A: If I could add, I think NERC
reliability standards, which have been in place for a
number of years in various forms and these are a new
set of requirements, are traditionally intended to
deal with low probability/high consequence events with
widespread blackouts and to ensure that each party is

upholding their part of this bargain of being interconnected. So I wouldn't expect to see a benefit in terms of improved availability, or reduced forest outages, or improved SADI or CADI as a result of this work, but we would expect to have an incremental reduction in the broader risk in the system of blackout, a widespread blackout, for example, as was experienced in the eastern U.S.

So I think it's important to set expectations about what we're delivering with this initiative versus what we're not.

MR. FULTON: Q: Thank you.

MS. KURSCHNER: A: And of course the risk of not being part of that NERC community is huge, in terms of the consequences if we for some reason were not able to participate in the reserve sharing and so on.

MR. FULTON: Q: Right.

Burrard Generating Station is the next topic, and page 4-21 of the application, section 4.6.3.1 provides a summary of the role that Burrard has played. So page 4-21, the application.

MR. O'RILEY: A: We have that.

MR. FULTON: Q: Okay. So you'll agree with me that that sections provides a summary of the role that Burrard has played and is intended to play in the future.

MR. O'RILEY: A: Yes, I would just make one qualification. There's really two decisions in play with respect to Burrard, and one decision is the decision to continue to rely on the plant beyond 2014 for energy and capacity, and that's the subject of the LTAP. So I'll be back in January, I believe, to talk about that.

This decision that we're talking about here relates to the decision to recall three of the units to generating mode from just synchronous condense mode, and that was a decision that was anticipated, I guess, in the last '05-06 hearing where we talked about the option to bring those units back, and we have in fact had to do that because of load growth on the system and our supply demand shortfall.

MR. FULTON: Q: And so would you agree with me that there has been or there's contemplated to be some change of use from the way Burrard has been used? And say in fiscals '07 and '08, wasn't Burrard basically operating only three units and used for spinning reserve and backup?

MR. O'RILEY: A: We've brought back one unit a year. We brought back -- we're bringing back the sixth unit this year. In calendar '07 we brought back the fifth unit, and in calendar '06 we brought back the fourth unit. So we've been increasing our reliance on

Burrard for peak generating capability, primarily in the winter but not entirely in the winter, as we've -- in the fall of 2006 we relied on it for system energy for a number of months. In February of this year we've relied on it for energy to back up our system, because of this constraint on the Peace River, the size constraint.

So, I think the role that Burrard is playing with respect to these six units, between now and 2014, is not changing. What's changing is the number of units that are in generating mode.

**Proceeding Time 2:16 p.m. T49**

MR. FULTON: Q: Okay, thank you.
MS. KURSCHNER: A: And we did, in fact, run full five units last -- well, this winter, in January/February.
MR. FULTON: Q: All right, thank you. And in terms of the fixed term initiatives, the proposed amounts for Burrard for fiscal '09 and '10 are 3.2 million and 3.9 million? Do you agree with that?
MR. DUNLOP: A: Yes, that's correct.
MR. FULTON: Q: Okay. At page 4 -- back to page 4-21, there is a reference in line 14 to 17 to covering the expenditures covering the costs associated with repairing cracks in the superheater tubes of all six units, and inspections of the power boiler required by Power Engineers, Boiler, Pressure Vessel and

Refrigeration Safety Regulation. Is the ongoing maintenance being done on the superheater tubes of all six units?
MR. DUNLOP: A: Yes, it is.
MR. FULTON: Q: Okay. And was there any provision related to the repair of cracks in the superheater unit -- the superheater tubes of the units included in the 2008 RRA?
MR. DUNLOP: A: No, there was not.
MR. FULTON: Q: Is the power boiler being inspected at the present time?
MR. DUNLOP: A: Yes, there have been recent changes to the Power Engineers, Boiler, Pressure Vessel and Refrigeration Safety Regulation that requires the boilers now to be inspected every other year.
MR. FULTON: Q: Okay. And was there any provision for inspection of the power boiler included in the fiscal 2008 RRA?
MR. DUNLOP: A: There was for the three units that were in generate mode. There was not for the three units that were in the '07/08 RRA put in long-term storage.
MR. FULTON: Q: And briefly, just to go back to the super-heater tubes, can you tell us what the superheater tubes do?
MR. DUNLOP: A: The superheater tubes are at the very top of the boiler, and they are heated by the flue gas

in the very last stage before the steam enters the turbine.
MR. FULTON: Q: Thank you. Next topic is civil maintenance generation, and Table 4-2 at page 4-16 of the application shows that the operating costs for civil maintenance generation are 3.5 and 5.5 million for the two fiscal years.
MR. DUNLOP: A: Yes, that's correct.
MR. FULTON: Q: Okay. And the civil maintenance initiative is explained on page 4-21, and there are three bullets, beginning at line 20, that talk about the components of the initiative?
MR. DUNLOP: A: Yes, I have that.
MR. FULTON: Q: Right. And the initiative is also spoken to at BCUC IR 1.50.9 at Exhibit B5-1.
MR. DUNLOP: A: Yes.
MR. FULTON: Q: Which summarizes the costs.
MR. DUNLOP: A: Yes.
MR. FULTON: Q: Of the initiative. Okay. Has there been ongoing maintenance of the civil assets in previous years, Mr. Dunlop?
MR. DUNLOP: A: Yes, there has been maintenance done on civil assets previously.
MR. FULTON: Q: Okay. Was there any provision for spending on the maintenance of civil assets in the 2008 RRA?

**Proceeding Time 2:21 p.m. T50**

MR. DUNLOP: A: Yes, there was provision for civil maintenance asset in the 2008 RRA. B.C. Hydro's civil assets are in declining condition, and maintenance has not been done on a consistent basis on our civil assets across the fleet. Unlike our electrical and mechanical equipment in our generating stations, where we have implemented the RCM methodology for developing maintenance standards, maintenance of civil assets was really done on an individual basis as determined by the plan.

So as we've indicated in the application, the purpose of this initiative is to do maintenance that we have not been able to do in recent years, as well as using the RCM methodology, develop maintenance standards for our civil assets that can be applied consistently across the fleet. We believe that it will take about five to six years for us to do the maintenance that's not been done in recent years, and at the end of that five- or six-year period we anticipate that the efficiencies gained from having fleet-wide standards for maintenance of our civil assets will fund any increase in our civil maintenance that may be required.

MR. FULTON: Q: Can you tell us what the budgeted amount in the fiscal 2008 RRA was for the maintenance

of civil assets, and also what the actual spend was?
MR. DUNLOP: A: In the fiscal '07, fiscal '08 RRA, civil maintenance was not broken out as a line item, but I can say that and I'd refer to BCOAPO Information Request 1.28.(a), actual civil maintenance for fiscal '07 and fiscal '08 is detailed in that information response. In fiscal 2007, total spending was $17.8 million. Fiscal 2008, spending was $17 million.
MR. FULTON: Q: Thank you.
I'd next like to turn to generation asset maintenance and security, and again back to Table 4-2, the amounts for the general asset maintenance and security improvement are 3.4 million in fiscal 2009 and 4.1 million in fiscal 2010?
MR. DUNLOP: A: Yes.
MR. FULTON: Q: And if you'd turn forward to page 4-26 of the application, the lines 13 to 15, the total operating costs for security improvement costs are .4 million in fiscal 2009 and .6 million in 2010?
MR. DUNLOP: A: Yes.
MR. FULTON: Q: And the general asset maintenance initiative costs are 3.4 million in fiscal '9 and 3.5 million in fiscal 2010.
MR. DUNLOP: A: Yes, and the security costs of .4 million for fiscal 2009 and .6 million for fiscal 2010 are in the total 3.4 and 4.1.

MR. FULTON: Q: I see, okay, thank you.

**Proceeding Time 2:26 p.m. T51**

MR. FULTON: Q: I see, okay, thank you.

Did B.C. Hydro perform a cost-benefit analysis of the fiscal 2009/2010 general asset maintenance and security improvement expenditures?

MR. CHRISTIAN: I'm going to rise just for a moment here because Mr. Fulton is correctly reading the name of the initiative here as it's stated, general asset maintenance and security improvements, but in fact if you flip over the page, you'll see that it's actually called -- on page 4.6.3.5, on page 4-25, the correct name of the initiative is actually the generation asset maintenance and security improvements initiative. So on the table there, that we're -- Mr. Fulton is referring to, Table 4-2, that's just a typo, where that word "general" appears in the name of that initiative.

MR. FULTON: Okay, thank you. So if the --

MR. CHRISTIAN: So I just -- so that it clears up -- I think probably help to keep the record a little clearer.

MR. FULTON: Q: And so when I was referring to general asset maintenance and security improvement, I hope you understood me to mean generation asset maintenance and security improvement. Did you?

MR. DUNLOP: A: I had understood you to mean the asset maintenance and security initiative.
MR. FULTON: Q: Yes. Thank you. Very diplomatic. So, was a cost-benefit analysis performed of the fiscal 2009 and fiscal 2010 generation asset maintenance and security improvement expenditures?
MR. DUNLOP: A: I don't believe a cost-benefit analysis was done. The maintenance initiative includes funding for maintenance that has not been completed in recent years, and also funding for seven maintenance planner positions, one for each of our hydro generation areas. The seven maintenance planners are required to better plan our maintenance and capital work. The maintenance planners, which are consistent with best practices in capital-intensive industries such as pulp and paper, airlines and refineries, the maintenance planners will enable our trades people to be more productive by ensuring that work is properly planned in advance, by ensuring that materials are on hand before the job starts, any special tools that are required are also on hand before the work begins.
Again, we expect the maintenance planners will improve our efficiency to the point that after the -- and we expect the maintenance planners won't become fully functional for two to three years. But after that two to three period -- after that two- to

three-year period, it's expected that the efficiencies that will be gained from having the maintenance planners in place will fully fund their costs.

MR. O'RILEY: A: If I could just add, I think the benefit of this initiative needs to be considered in light of the pressures -- the cost pressures on the base maintenance costs. We're seeing a general increase in the requirement for maintenance of equipment as the equipment ages, so that the demands are rising. An example of that is the spillway maintenance that we're doing -- spillway gate maintenance that we're doing, which is approximately a million dollars a year, and that's not maintenance that -- it's maintenance that's never been done in our system.

Similar pressures related to the aging assets, an example being the 7 by 24 -- 24-hour coverage we've implemented at John Hart Generating Station for five electricians to be able to respond quickly when there's a unit problem that leads to a flow interruption, and that's about $600,000 a year, and that's coming into the base. We've seen an increase of approximately two and a half million dollars in overtime per year, and that's required because of capacity constraints and shorter and tighter outage windows.

**Proceeding Time 2:30 p.m. T52**

And in addition to that, we've had a standard labour rate increase for our trades people of approximately 3 to 4 million per year. So that adds up. That alone adds up to 7 or 8 million a year, which is a fairly significant hit to a maintenance budget that is approximately 75 million a year. That's the figure for F09.

So we're hoping that with this initiative, as Mr. Dunlop said, the maintenance planners will at least recover their own cost, and there's potential for some upside there as well. But we're not able to accommodate this additional maintenance work in light of the other pressures on the base that I've just described.

MR. FULTON: Q: Okay, thank you.

The next topic relates to the EARG capital improvement process, and that is discussed beginning at page 4-29 of the application, line 20 and following.

MR. O'RILEY: A: I have that, thank you.

MR. FULTON: Q: And is B.C. Hydro requesting funds for both capital and operating costs relating to this initiative?

MR. O'RILEY: A: We are.

MR. FULTON: Q: And why is that?

MR. ELDRIDGE: A: The implementation of the project has a component of each, a capital component in terms of the software and the hardware, and then a OMA component in terms of the training and the process review work that happens before the project gets implemented.

MR. FULTON: Q: And was the EARG capital improvement process initiative included in the fiscal 2008 RRA?

MR. ELDRIDGE: A: Phase 1 of the project was included in the '08 RRA. '09 is an expansion of that project and Phase 2 of that project.

MR. FULTON: Q: What was the budget in the fiscal 2008 RRA for Phase 1?

MR. ELDRIDGE: A: In 2008 the budget was approximately $1.6 million in operating costs. And I think I need to explain the source of the funding that we have for the Phase 1 and the Phase 2 and why they're different. The Office of the Chief Information Officer, and I think you spoke to Mr. Stuckert last week, they have an operating budget and a capital budget that they allocate to the business groups for sustaining and maintenance of our IT systems.

In 2008 we applied to the Office of the CIO for funding for this project, for the Phase 1 of this project. Phase 1 was very much focused on looking at the existing tools and processes we have and improving them. So we looked at our processes in detail. We looked at ways that we could change the business rules and the functionality of the existing software we had, to make them more efficient and to get productivity improvements. So for that reason, we received $1.6 million from the CIO budget in fiscal '08.

The project that we are initiating in fiscal '09, which we're characterizing as Phase 2 but it really is quite distinct from Phase 1, we are requesting an additional $1.8 million. So the assumption is -- well, what's actually happened is the $1.6 million of funding we received in fiscal '08 has actually gone -- or 1.6 million has gone back to the CIO Office for them to fund other maintenance and sustaining initiatives around the company. We are requesting $1.8 million for Phase 2. We view Phase 2 again as fundamentally different from Phase 1 and we characterize it as a transformational issue. We are not trying to change software, our processes. We are trying to put in place new software and new processes to reflect the significant increase to our capital plan, the increasing number of users for the software that we require. And to put it in context, we have a capital planning and forecasting software that has been in place for over ten years.

So we're looking to replace that, and

really the replacement and the goal of this project is to get a suite of tools to project managers to be able to work with the increasing number of projects and to ensure that we have better reporting on those projects, both on a project basis, a program and a portfolio basis.

So the focus of the two phases are quite different, and the funding sources are slightly different as well.

**Proceeding Time 2:35 p.m. T53**

MR. FULTON: Q: What was the actual spend in fiscal 2008?

MR. ELDRIDGE: A: Our OMA plan in fiscal '08 was $1.6 million, as I mentioned. Our actual was 1.295 million. Some of that amount has flowed into fiscal '09, but a fairly modest amount, around $55,000. So the total spend on phase 1 of the project was approximately 1.35 million on a budget or a plan of 1.6.

MR. FULTON: Q: All right, thank you. The EARG capital improvement initiative is not included in the fiscal 2009 budget, is it?

MR. ELDRIDGE: A: The phase 1 is not, no.

MR. FULTON: Q: Right. Phase 2 is?

MR. ELDRIDGE: A: Phase 2 is. Phase 2 is this project we have just been discussing. The engineering,

aboriginal relations, and generation, capital improvement process project.
MR. FULTON: Q: All right. And I'm sorry, did you say when Phase 2 is scheduled to begin?
MR. ELDRIDGE: A: In fiscal '09.
MR. FULTON: Q: Yes, but has it begun?
MR. ELDRIDGE: A: Already -- it's already begun. It has.
MR. FULTON: Q: Okay. So, when did it begin?
MR. ELDRIDGE: A: It began -- I believe it began in April.
MR. FULTON: Q: Okay.
MR. ELDRIDGE: A: We have two dedicated project managers to the project. There's a steering committee finalizing the scope of the project, looking at the different IT applications we could use to reach our objectives on this project. So there are a number of activities ongoing.
MR. FULTON: Q: Okay. And where are you in terms of your actual spend and the budgeted spend on the project at this point?
MR. ELDRIDGE: A: Give me one minute.
MR. FULTON: Q: The budget is $1.8.
MR. ELDRIDGE: A: That's correct.
I do have that number, but unfortunately I'm not picking it out very quickly, so if I may --

MR. FULTON: Q: All right, if you could supply that by way of undertaking, that will be fine.
MR. ELDRIDGE: A: I will, please.

**Information Request**

MR. FULTON: Q: Thank you. If you turn over to page 4-30 in the application, there's a reference to -- in line 2 to existing work management tools such as PassPort. Can you tell us what PassPort is, and does?
MR. ELDRIDGE: A: Mr. Dunlop can certainly speak to how we use PassPort. I can speak to how it's relevant to this project.
MR. FULTON: Q: Yes, all right, if you would speak to its relevance to the project for us.
MR. ELDRIDGE: A: Sure. One of the primary benefits of the Phase 1 of the project was to further integrate our capital planning work and our capital delivery work with the operational management of projects at the plants. We had circumstances where, because they were managed -- not siloed, but they were -- they weren't as fully integrated as they could be, the Phase 1 of the project, one of the key goals of that Phase 1 was to look at combining those two pieces of work.
What happened often was, we had a team working on a capital project. They would arrive at the plant to start working on that capital project

without fully having the plant resources they required lined up and, in some instances, the plant resources were actually pulled off other maintenance work to work on a capital project. So Phase 1 ensured better integration of that capital work with the maintenance work by requiring that every capital project needs to go into PassPort, which is the primary tool used by the maintenance engineers, and by the maintenance staff, to ensure that any of the plant resources required were fully booked within that work management system.

So that's where PassPort comes into it. It's to fully integrate both our capital planning work with our general asset management work at the facility.

MR. FULTON: Q: And, Mr. Dunlop, do you have anything you like to add about use?

MR. DUNLOP: A: No, PassPort is a computerized maintenance management system. It is the primary work management system, as Mr. Eldridge indicated at our facilities. It's where we track all maintenance that's due in future years. It's how we collect costs associated with the maintenance of particular equipment types. And it's the primary tool that our maintenance staff use for planning all the work of the generating station staff.

**Proceeding Time 2:40 p.m. T54**

MR. FULTON: Q: Thank you.
I'd next like to turn to fiscal 2009, fiscal 2010 capital expenditures, and Exhibit A2-21, which is a witness aid that summarizes Appendix J.
MR. O'RILEY: A: Mr. Dunlop will speak to that.
MR. FULTON: Q: All right, thank you. Mr. Dunlop, are there any projects other than those that appear at lines 1 through 39, that belong to the EARG Group? Oh, and plus 42 and 43. So 1 through 39 is a summary of the hydroelectric generation. And then thermal generation is at 42 and 43.
MR. DUNLOP: A: Also at line 63, the EARG Capital Improvement Process Project.
MR. FULTON: Q: Oh, thank you. Now, if you look at line 1 for Aberfeldie Redevelopment, you'll see that there's an existing CPCN for that, and line 29 has an existing CPCN. And I'm correct in -- the summary is correct that none of the other projects that are listed for EARG and that you've identified for EARG have CPCNs?
MR. DUNLOP: A: I believe that's correct, although I believe that some of the expenditures were approved in the fiscal '07, fiscal '08 NSA.
MR. FULTON: Q: Yes, thank you. And I had a discussion with Mr. Rodford on Panel 5 about prioritizing

projects, and also with Mr. Stuckert and Mr. Lintunen on the areas in Exhibit A2-21 that they are responsible for. Mr. Rodford had indicated that for the projects for which he is responsible, they've gone through a filter before they'd arrived at where they were in terms of their phasing. And I'd asked the other panels who had responsibility for projects on A2-21 if they were able to prioritize the projects that were within their area of responsibility.

So are you able to prioritize those projects within EARG's area of responsibility, giving them 10 for the most important and 1 for the least important?

MR. DUNLOP: A: Yes, with a great deal of difficulty. Like field operations, we do have a process within EARG for prioritizing all our capital expenditures, and we filed some information on our prioritization process in response to BCOAPO 1.34.(c), and that's our B.C. Hydro risk matrix. And for every capital project that we consider, we do a risk assessment. And the risk matrix has on the vertical axis probabilities, and on the horizontal axis consequences.

**Proceeding Time 2:45 p.m. T55**

And so for every capital project that we consider, we do a risk assessment in terms of looking at the probability and the consequences associated with not undertaking that project. So, in response to the discussions that you had with Mr. Christian, we translated the risk assessment rating that resulted from the capital prioritization process to your scale of 1 to 10. And I do have that information.

Would you like me -- I can go through the projects --

MR. FULTON: Q: Yes. Thank you.

MR. DUNLOP: A: We did not give a ranking to projects that were already in the implementation phase. So if contracts had been let and we were -- and work was already underway, we did not give a ranking to those projects. So the Aberfeldie redevelopment project, which is nearing completion, we did not rank. The Bridge River 1 intake slope stability we gave a rank of 8. Bridge River staff housing redevelopment, a rank of 8. Bridge River unit 5 rehabilitation and Bridge River unit 6 rehabilitation, a rank of 9. Bridge River unit 5, turbine inlet valve replacement, a rank of 9. Cheakamus Unit 1 and Unit 2 generator replacement, a rank of 9. The Cheakamus turbine and runner upgrade project is a growth project. It's also in the implementation phase, so it was not ranked.

Coquitlam Dam seismic improvement has been completed and was not ranked. GMS spillway crane upgrade has been completed and was not ranked. GMS transformer replacement, the contract has been awarded for the replacement of those transformers and so that project was not ranked. GMS Units 1 to 4, generator stator replacement, that -- the contract has been let for that work. A stator has been replaced on several of the units, and so that was not ranked. Similarly, the Unit 6 and Unit 7 rotar pole replacement is just about complete, and so that project was not ranked.

G.M. Shrum digital modernization, a rank of 7. G.M. Shrum low level outlet and sluice gate improvement, 9. G.M. Shrum station service upgrade, 8. G.M. Shrum Unit 6 to 8, capacity increase, is in the implementation phase and was not ranked. G.M. Shrum Unit 1 to 5, turbine rehabilitation, 10.

John Hart replacement project, 10. Jordan River governor and protection replacement is in the implementation phase and was not ranked. Kootenay Canal forebay seepage control berm and slab repair, 10. La Joie north conduit seismic improvement was not ranked because it's in the implementation phase. La Joie seismic improvements, 10. Mica digital infrastructure and digital exciters, 8. Mica SF6 gas insulated switch gear replacement, 9. Mica Unit 1 to 4, stator replacement is in the implementation phase, two units have -- three units have been done, and it was not ranked. Similarly with Peace Canyon Unit 1 to

4 stator replacement and Peace Canyon Unit 1 to 4 turbine overhaul, by the end of this calendar year three units will be complete, of the four that are to be done.

**Proceeding Time 2:50 p.m. T56**

Revelstoke 5 was not ranked, it's in implementation. Ruskin Dam safety improvements and generating station redevelopment, 9. Ruskin Dam safety improvement right abutment, 9. Seven Mile exciter system replacement is in the implementation phase. Spillway gate reliability upgrade program, 10. Strathcona seismic and seepage, 9. Mica Upper Columbia capacity additions at Mica and Revelstoke is a growth project and we did not rank that. W.A.C. Bennett Dam rip rap upgrade, 9. Wahleach Penstock inlet valve replacement, 9. Seven Mile security improvements, 8. Williston dust mitigation program is in the implementation phase and was not ranked.

And I am afraid I do not have with me the information on the Burrard asbestos management program.

MR. FULTON: Q: I'm assuming that wouldn't be ranked as it was in the implementation phase in any event.

MR. DUNLOP: A: It is. It's something that is part of ongoing work at Burrard Thermal. It's required to meet safety regulations -- or I'm sorry, WCB OSH regulations, and so would have a very high rating. The Fort Nelson Resource Smart upgrade is a growth project and so we wouldn't rate that. And I would have to get the information on the capital improvement process project. I'm sorry that I don't have that with me.

MR. FULTON: Q: That's something that you could provide by way of undertaking then, thank you.

**Information Request**

MR. DUNLOP: A: I'd also add that that is some 39 projects, plus the two thermal, plus the EARG capital improvement process project.

There were, as part of our capital prioritization process, 25 projects greater than $5 million that were not funded in the fiscal '09, fiscal '10 period. And I'd just quickly like to give you a sense of the projects that were not funded. Mica Unit 1 and 2 turbine rehabilitation, which is a growth project, was not funded. Alouette redevelopment, we would give a rank -- on the same basis we would give a rank of 10 and it was not funded. Fiscal '09 spillway gate program was not funded. It would also have a rank of 10. Falls River redevelopment, a rank of 10. Buntzen, Lake Buntzen runner upgrade, a rank of 10, not funded. Mica Dam instrumentation improvements and grouting, 10, not funded. Bridge, 2 Unit 7 and 8 rehabilitation, both rank 9. GMS Dam improvements, compaction grouting beyond the outlet wells, a 9. Keenleyside concrete dam seismic upgrade, 9. Kootenay Canal exciter replacements Kootenay Canal government replacements, both rank 9, were not funded. La Dore intake gate refurbishment, 9. Puntledge Comox dam safety improvements, 9. Ash River redevelopment, 8, not funded. Klahomb upgrade, 8. Klahomb turbine system replacement, 8. Klahomb Unit 1 generator replacement, 8. Kootenay Canal dam and seismic upgrades, 8. Jordan long-term dam access improvements, 7. Seven Mile protection and control replacement, 7. Mica powerhouse roof replacement, 6. Mica replace Unit 1 to Unit 4, unit circuit breakers, 3. Peace Canyon control system upgrades, 3. Vancouver Island communications network, 3.

So that gives you a sense of some very important projects that were not funded as part of the prioritization process, in addition to those projects that did receive funding.

**Proceeding Time 2:55 p.m. T57**

MR. FULTON: Q: Thank you, Mr. Dunlop. I'd next like to move to my final area, which is hedging.

COMMISSIONER MILBOURNE: Before you go away, could I ask a question because the context is kind of right here?

MR. FULTON: Yes.

COMMISSIONER MILBOURNE: Rather than trying to recreate it later? Thank you.

Given that you've got a bunch of 10s and 9s on the list you put in front of us, the list that's proposed to go forward with, and there's a bunch of 10s and 9s on your list that you didn't come forward with, and there's a bunch of 8s on the list you brought forward, and a bunch of 8s and 7s and stuff on the list you didn't bring forward. This may be an awful dumb question, but why wouldn't you, if your ranking system is "real", why wouldn't we have all the 9s and 10s on the list you brought forward?

MR. DUNLOP: A: The ranking system -- projects are prioritized on the basis of probability and consequences.

COMMISSIONER MILBOURNE: I understand that.

MR. DUNLOP: A: But as part of our planning process, we also look at resourcing, and what resources are available to do the work. And so for example, we had identified John Hart redevelopment, Ruskin redevelopment, Alouette redevelopment and Falls River redevelopment as very high priority projects. But we recognize that from a resourcing perspective it's not possible to do all those four projects simultaneously. And so, although they're all ranked the same, from a resort -- we have to take a step back and say, from a resourcing perspective, it's unrealistic to be able to complete all of those projects together. And so we have to, in the case of the redevelopments, we looked at other factors such as Mr. O'Riley this morning talked about the importance of the Campbell River as a salmon-bearing river in the province.

And so, it is more important that we consider the redevelopment of John Hart than, say, Falls River on the north coast. And so, because it's not possible to do all the work that is necessary, even after projects had been prioritized, we have to do a further prioritization based on resource availability.

COMMISSIONER MILBOURNE: Just so I understand your resource constraint, is that not one you impose on yourself? Because you're managing all these -- you execute all these projects with your own resources?

MR. O'RILEY: A: I can speak to that. We are using a mix of internal and external resources to manage these projects. So for example the John Hart, Ruskin, Upper Columbia projects we're managing jointly in integrated teams with a U.S. engineering firm that had moved people into our offices to work with our people to manage them. So we are drawing on resources, external resources. The Fort Nelson work that we've taken on, that's got a very pressing customer demand associated with it, which we'll talk about in the LTAP, and we've gone to AMEC to provide project resources.

Some of the projects that Mr. Dunlop talked about, the dam safety projects, they draw on very limited geotech resources. And when I say "limited", they are limited internally and externally. Like, there is a certain pool of people that do that kind of work across the country, and we've got them pretty busy here, and other utilities have them busy elsewhere, and so you can only push so much work through that type. So we have, in addition to the prioritization that Mr. Dunlop spoke about, we have a special prioritization that we apply for dam safety projects to make sure we're working on the most important, most critical projects there.

And we probably have, if anything, we're probably pushing the limits in terms of the number of dam safety projects we're trying to push through this -- push through at this point in time.

The other point I would make is, another consideration -- there's inevitably, when you're talking about these large projects, it's not a formulaic approach to prioritization. There's some judgment in play. And for example, Alouette generating station is something that's in pressing need of redevelopment. And it just past its $80^{th}$

birthday. It was built in 1928, and I'm told when it was built it was actually they used a lot of used parts when they put it together.

**Proceeding Time 3:00 p.m. T58**

COMMISSIONER MILBOURNE: Probably good parts.

MR. O'RILEY: A: Yeah, I'm sure they were great. But, and the issues with Alouette is there were some very serious safety hazards there, and there's also some environmental hazards. So we've got oil-filled transformers without proper containment, for example.

On the safety front, because that's such a priority for us, we were able to deal with the most pressing safety issues. Like, we had exposed electrical bus, that could cause people to come within limits of approach. We had a limited access. We were able to spend about $60,000 in the last year and put in some very effective barriers to deal with the most pressing safety issues. So that's given us a bit of comfort that we can put -- we can delay that work until we can -- until we can free up some resources from another, other pool.

The other point I'd like to make is we are looking at some different procurement models. And with the John Hart project, for example, we're working with Partnerships B.C. from the -- you know, another Crown corporation of the provincial government. And the province has a requirement that any project that's over $20 million in cost be considered as public private partnership, a P3. And so that approach doesn't lend itself to some of the projects we're talking about, like stators for example. It does -- it potentially does lend itself to largely stand-alone redevelopments. And so we are looking at that for John Hart, and there's some constraints that have been composed on us. One from the province, one that B.C. Hydro will continue to own that asset, and two that B.C. Hydro staff will continue to operate and maintain that asset. So we are looking at that procurement option in light of those constraints and we think there may be an opportunity to draw, rely more heavily on the market to bring in these resources.

COMMISSIONER MILBOURNE: At the risk of delaying Mr. Fulton further, I was going to ask this question later anyway so I'll ask it now. You've dealt with the P3 aspect of it. Do you include EPC contracts and outsourcing the whole project management function, engineering procurement and construction, and the risk as part of your tool kit? Because the reason I ask that is I kind of look at the -- I would call it material increase in your resource base.

MR. O'RILEY: A: Yes.

COMMISSIONER MILBOURNE: And then I look at you're saying you can't do the 9s and 10s because you haven't got the resources. And it kind of rattles in my head that somewhere there's a solution to that problem, that it should lie in the area of -- given the amount of work you've got to do over the longer period of time, that it would be, one would think, EPC capable firms would be interested in acquiring some of this business and executing it for you and taking that whole burden off you.

MR. O'RILEY: A: Yes, and we've been pushing the envelope, if you will, to use that cliché, in terms of our procurement approach. Traditionally B.C. Hydro would do design, they'd build -- so they would conceive of the project, they would do the design, they would break it up into packages, quite small packages, and then put them individually out to market.

Where we're looking at projects that are very much ground field, redevelopments of existing -- or replacements of existing components or series of components, we tend to do that, though we are relying to a greater extent on external engineers and designers to do the work. And I can give you two examples. One is the Aberfeldie redevelopment, which we've broken into three packages. One is an engineering package. We had Knight Peacehold do that.

We had a civil contractor, Western Versatile, and then we had the water to wire piece, which is the VA Tech. And all we did on that was the project management and construction management, and that worked out to -- that's roughly a $95 million project at the high end of the authorized amount. And our costs on that project will be about $7 million so about 8 percent of the total cost.

COMMISSIONER MILBOURNE: I'm looking at the model we outsource. You do the functional specification, performance specification, you outsource the package--

MR. O'RILEY: A: Yeah.

COMMISSIONER MILBOURNE: -- along with the risk.

MR. O'RILEY: A: Yes, and that's what we're looking at with John Hart.

COMMISSIONER MILBOURNE: Okay.

MR. O'RILEY: A: That's sort of the next iteration of that would be -- that's what we're looking at --

COMMISSIONER MILBOURNE: That could be done independent of the PPP process. There's all sorts of EPC stuff being built as we speak.

MR. O'RILEY: A: Yes.

COMMISSIONER MILBOURNE: Most of the real economy has tried to move in that direction, but there are some issues with respect to getting people who are willing to take on the risk.

MR. O'RILEY: A: Yes. And especially for these civil
-- projects that have a large civil component or a large geotech component, there is always a concern taking that risk, like the -- on the Aberfeldie job, the toughest part of that project was getting out of the ground. Once we got out of the ground, it went very smoothly. But the coffer dam, the excavations, that was the tough part of the contractor, and I don't think he made a lot of money on that part of the job.

**Proceeding Time 3:05 p.m. T59**

COMMISSIONER MILBOURNE: This Commission recently approved a project of -- I forget how many hundreds of millions that was done and executed, the principal parts of which were executed on that basis. So, there's not fresh ground to be ploughed here.

MR. O'RILEY: A: Exactly.

COMMISSIONER MILBOURNE: It's a matter of effective use of resources. So, anyway, thank you, I'll leave it at that.

COMMISSIONER RHODES: Sorry, I have a question too. The 25 projects that weren't funded, where is that decision made? In what level of the organization?

MR. DUNLOP: A: Ultimately the decision -- ultimately that decision is made at the EARG management --

MR. O'RILEY: A: Yeah, if I could clarify -- yeah. The capital plan ultimately goes to the board as part of a service plan process. And we would take as part of that, we would talk about the projects that we're working on as well as the projects that we're not. And have a conversation around that. So we've prepared some materials for this coming year, '10 and '11 and '12, to share with our senior executive and ultimately with the Board to inform that. Because these decisions -- for example, if we were to not proceed with John Hart, there's a significant risk that extends beyond the corporation, the bounds of the corporation. So that, to defer John Hart, for example, would have to be a Board decision and conceivably the province would need to be involved in that, because we're not -- it's not a risk that's contained within the company. It goes beyond the bounds of the company.

COMMISSIONER RHODES: Okay, so these 25 projects, then, at your group level you've decided to not to put them forward but to flag them as projects that you haven't put forward, basically?

MR. O'RILEY: A: We would -- what we would do in terms of our presentation is, we would say this is what we're bringing forward, and these are the ones where -- when we say they're not funded, what it means implicitly is they're just deferred. Right? That's what it means. So, we've got Alouette starting, I think, two years out now. So we're trying to get to Alouette fairly quickly, keep one of those smaller redevelopment projects going on. Have one of them going on at a time.

COMMISSIONER RHODES: Thank you.

MR. O'RILEY: A: But they are very important decisions, what risks you address and what risks you don't. Certainly the dam safety risk matrix is reviewed at every -- there's a Board sub-committee related to dam safety, and they would review the dam safety risk matrix on a quarterly basis and talk about what we're doing in terms of mitigation and resolution of those issues. And other risks that we've talked about. We regularly go back and talk about the John Hart and the Ruskin progress, and the spillway gates, for example, which is a major, major program in our organization.

MR. FULTON: Madam Chair, I expect that this next area will take about 20 minutes.

THE CHAIRPERSON: I wonder if this is a good time for a break, or would you prefer to finish first?

MR. FULTON: I am in your hands. I expect I'll be about 20 minutes.

THE CHAIRPERSON: Let's break. 15 minutes.

**(PROCEEDINGS ADJOURNED AT 3:08 P.M.)**

**(PROCEEDINGS RESUMED AT 3:25 P.M.)** **T/6061**

THE CHAIRPERSON: Please be seated.

Mr. Fulton.

MR. FULTON: Madam Chair, before I begin, I did canvass with Mr. Christian, who had in turn canvassed with other counsel, the possibility of sitting late tonight subject to the Commission's approval, to get finished this panel. And counsel are all in favour of sitting late to finish this panel.

MR. CHRISTIAN: I should say we're all in favour or we weren't going to take a position. I know Ms. Worth had an engagement at 5:00 that she would have -- going to stay as long as she could, is what she advised me.

THE CHAIRPERSON: Okay, thank you, because that certainly is the Panel's preference also. This Panel. I presume the witness panel's preference as well, but certainly the Commission Panel also would prefer to complete the session tonight rather than returning tomorrow for an hour or two. And it shouldn't -- hopefully won't take that long extra.

MR. FULTON: Yes, and perhaps if -- we do need to bear in mind that the court reporter will probably need a break at some point, depending on how long we go.

THE CHAIRPERSON: We'll take care of our court reporter.

MR. FULTON: Q: Panel, I'd next and lastly like to turn to the topic of hedging, and I want to begin the discussion on hedging by referring you to Exhibit B-26. And B-26 includes the original response to BCUC

IR 1.23.5.14, and a revised response to that IR. And the original response spoke of the primary benefit of the hedging program in the third paragraph of B-26, and I'll wait for you to catch up to me, Ms. Kurschner.

MS. KURSCHNER: A: I have it.

MR. FULTON: Q: And then in the revised response, the primary benefit is discussed in the third paragraph which is page 2 of 3. The original question asked for discussion of whether the value to customers of the ability of a gas hedging program to reduce rate volatility justifies a lot likely costs of the program. And the response, though, relates to both gas and electricity, does it?

**Proceeding Time 3:28 p.m. T62**

MS. KURSCHNER: A: That is correct.

MR. FULTON: Q: Okay. And the original response in paragraph 3, which is page 1 of 3, five lines down, spoke of an estimated 0.3 percent reduction in the proposed deferral account rate rider for the top 25 percent of high cost outcomes. And the revised response refers, in the third paragraph of the revised response, lines 6 and following, to estimated -- the benefit of hedging is estimated to be a reduction of about 1.5 percent in the proposed deferral account rate rider.

Can you tell us the reason for the change from the .3 percent to the 1.5 percent?
MS. KURSCHNER: A: It was a mistake. What we did is, we actually -- we worked off some of the simulation that we have prepared at the time when we gave the June BCUC workshop, and we made some assumptions about deferral accounts in that simulation. And unfortunately when this original response was prepared, we ran it through the deferral accounts twice. It was a mistake.
MR. FULTON: Q: Okay, thank you. Now, at page 3 of 3, there is a table headed "Multisequence costs of energy simulation results". And as I understand that table, it shows a single year of variation the cost of energy of $55 million as a hedging impact?
MS. KURSCHNER: A: That is correct.
MR. FULTON: Q: Okay. And can you explain how you get to that?
MS. KURSCHNER: A: Okay. So, we did a simulation and there is -- with assessing risk, you always have to make some assumptions. It's very hard to make it black and white. So, there is a number of assumptions in the notes below, such as -- at the time when we did the simulation, a typical domestic market transaction for gas and electricity short position was about 7,000 gWh, and that is about -- it was based on about two

and a half thousand gWh of electricity short -- sorry, gas short position and four and a half thousand of gigawatt hours of electricity short position.

We also assumed in the situation 50 percent hedge position for the upcoming year. So, that you would at all times hedge 50 percent of the short position.

**Proceeding Time 3:31 p.m. T63**

We then looked at what the single year variation in the cost of energy, which in this means -- in this sense mean the cost of the domestic market transactions, would be if you did not hedge. That's the unhedged variation. And then what it would be if we did hedge at the 50 percent level. So how much would it reduce the variation in the cost of the domestic market transaction? So if you recall, the basic premise of this hedging program is not to reduce cost but to reduce the variation from year to year.

MR. FULTON: Q: Yes. Right, thank you.

And on the second line of that table, there is a deferral account balance difference of 150 million. Can you tell us how one moves from the 55 million to the 150 million?

MS. KURSCHNER: A: Okay. So because we are looking at 25 percent of the highest -- of the worst outcomes, what you are looking at is at a sequence of years and how the balances would accumulate in the deferral account over time, including the clearing that is based on the proposed clearing mechanism in the application. There was a table if the balance is a certain amount, how are you going to clear it? So that was included in how we derive the deferral account balances. But because you're looking always at the 25 worst outcomes of the deferral account balances, that's why these balances are, you know, are substantially higher than what you are seeing, or the variability in those balances is higher than what you are seeing in the single year variation in the cost of domestic transactions.

MR. FULTON: Q: So is the 150 million a single year number though? Or is a cumulative number?

MS. KURSCHNER: A: No, that is a single year. But it's a single -- it's a variation in the given year but the balance has been accumulating over years.

MR. FULTON: Q: Okay. If you are looking at a single year impact, without accumulation, is the impact 55 million or .5 percent on the rate rider?

MS. KURSCHNER: A: If I just -- if I ignore deferral account balances and I purely look at the variation of costs of energy, in a single year, then the impact of hedging would be a reduction in the variations by $55 million.

**Proceeding Time 3:34 p.m. T64**

MR. FULTON: Q: Or half a percent on the rate rider.
MS. KURSCHNER: A: It's 55 -- do you have the table?
MR. CHRISTIAN: It's Table 6-2, shows the deferral account rate rider, and --
MS. KURSCHNER: A: So 55 would be --
MR. CHRISTIAN: Between 50 and 100 million dollars, the rate rider would be, as I understand the table, 0.5 percent.
MS. KURSCHNER: A: Okay, then, 0.5 percent is correct.
MR. FULTON: Q: Thank you. You'll agree with me that the rate rider is presently half a percent?
MS. KURSCHNER: A: I actually don't know, sorry.
MR. FULTON: Q: All right.
MR. CHRISTIAN: We can confirm that.

**Information Request**

MR. FULTON: Q: If there was a high cost outcome in fiscal 2009, can you tell us what would happen to the rider in fiscals 2010 and 2011 if B.C. Hydro was hedged?
MS. KURSCHNER: A: I can't tell you off the top of my head. I don't know what a high-cost outcome would mean. I mean, there is -- I would have to run a simulation of that. And this is certainly -- those are the type of things that we look at, but they continually change when you're depending on what the

position is. You have to realize, this is not our real position right now, right? The position is changing every month.

MR. FULTON: Q: Right.

MS. KURSCHNER: A: And we adjust our hedging strategy based on that changing position.

MR. FULTON: Q: Okay. If you had a low-cost outcome rather than a high-cost outcome, directionally, would you expect the effects to be the opposite of a high cost outcome?

MS. KURSCHNER: A: Yeah, they are approximately opposite. There is a slight skew, because we know that the worst outcomes on the high cost are -- can be higher than the best outcomes on the low cost. There is a little bit of a skew. But generally it would be close to offsetting.

MR. FULTON: Q: Right, thank you. I now have two documents that I would like to have marked exhibits, Madam Chair, and these are documents that I have previously provided to Mr. Christian. The first is page 2 of 2 from Exhibit B-3 in the B.C. Hydro residential inclining block RIB rate application, BCUC IR 1.4.7. And that I will believe should be marked Exhibit A2-26.

**Proceeding Time 3:37 p.m. T65**

THE HEARING OFFICER: A2-26.

**(PAGE 2 OF 2 FROM BCUC IR NO. 1.4.7, DATED MARCH 18, 2008 FROM B.C. HYDRO RIB RATE APPLICATION, MARKED AS EXHIBIT A2-26)**

MR. FULTON: And the second document is a witness aid styled "B.C. Hydro Residential Interim Rate as of October 1st, 2008". That could be marked Exhibit A2-28.

THE HEARING OFFICER: Exhibit A2-27.

THE CHAIRPERSON: 27.

MR. FULTON: Thank you.

**(WITNESS AID ENTITLED "B.C. HYDRO, RESIDENTIAL INTERIM RATES AS AT OCTOBER 1, 2008", MARKED EXHIBIT AS A2-27)**

MR. FULTON: Q: Now, if we begin with A2-26, I'm just going to take you down to the first paragraph below the graph, and in that response B.C. Hydro provided a medium consumption of the remaining accounts, 99 percent of the total 762 kilowatts per month, and the average consumption of 932 kilowatt hours per month. And it shows that the median residential total annual bill is approximately $608 a month, and the average residential customer -- or per year I should say; and for the average residential customer about $756. Would you agree with that?

MS. KURSCHNER: A: I have no idea where I am -- what line am I looking at?

MR. FULTON: Q: If you go to A2-27.

THE CHAIRPERSON: I think that's more like A2-27, right.
MR. O'RILEY: A: Right, which is the witness aid.
MR. FULTON: Q: Yes.
MS. KURSCHNER: A: And what line am I looking at? The median line 5 and 6?
MR. FULTON: Q: Line 22.
MS. KURSCHNER: A: Okay, so I see total median residential bill --
MR. FULTON: Q: Is 607.86.
MS. KURSCHNER: A: Annuals, yes, okay, yeah, we see that.
MR. FULTON: Q: And then if we go down to line 38.
MS. KURSCHNER: A: Yeah.
MR. FULTON: Q: It's 755.68.
MS. KURSCHNER: A: Yeah.
MR. FULTON: Q: So would you agree with me, subject to check, that those are reasonable calculations as to what the median and the average residential customer would pay?
MR. CHRISTIAN: And I'm going to object because that puts a burden on this witness panel that I don't think is at all appropriate. This is the Engineering, Aboriginal Relations and General Panel. They don't have any knowledge in their working lives with respect to any of the matters that are described here. This is just really, in my view, an effort to avoid putting

the evidence on that would otherwise have been done, putting a burden on B.C. Hydro that isn't appropriate in the circumstances.

In the circumstances I have in particular mind are, the Commission Panel might recall Mr. O'Riley's testimony and I can't remember when it was now, but it was with respect to what ultimately B.C. Hydro's position is on hedging. And I'm going to, at the risk of overstating it or oversimplifying it, the bottom line was, B.C. Hydro would like to do hedging of natural gas and electricity, or neither one. It's not a hill to die on for B.C. Hydro, and so in light of that evidence, and the amount of work that would be required by these people who aren't here to speak to this type of matter, or other folks back at Hydro, we don't think they should have to agree that those numbers are right even just subject to check.

**Proceeding Time 3:42 p.m. T66**

THE CHAIRPERSON: Perhaps, Mr. Fulton, you could try to further explain what you are trying to accomplish by going through these exhibits.

MR. FULTON: Yes. This exhibit was intended to attempt to show what the rate impact might be of hedging of gas -- of gas and electricity, and the effect of the 1.5 percent that we started off talking about in Exhibit B-26.

THE CHAIRPERSON: But now that you heard the objection by Mr. Christian, how can you justify the -- trying to walk this panel through this exercise?

MR. FULTON: Well, if the purpose, as we've heard several times now, and Ms. Kurschner indicated at the outset, was to reduce volatility in rates, then we would like to attempt to demonstrate what that impact might be. I do accept my friend's submission that these people might -- this panel might not be equipped to answer the question. But it is a hedging panel, so one would have thought that they would be able to say in a general sense what the impact might be.

MR. CHRISTIAN: Right, but the question, of course, was not a general question about what the impact might be. The question was for the witnesses to confirm, really, with a fairly lengthy spreadsheet containing quite a numbers that relates to B.C. Hydro's rate structure in a way that this panel is clearly not here to testify to. You know, and to some extent I can appreciate my friend's difficulties. As Commission counsel, he doesn't have the opportunity to put in evidence. And of course, neither does the opportunity to make argument. But really, what that just does is underscore the fact that, you know, this is not, in my view, the appropriate way to get information before the Commission Panel that will help them make a decision. Or, to put it another way, this could all have been put in an IR.

THE CHAIRPERSON: What is the -- I have another suggestion here. Would that help you, if you just asked the panel, assume that this is correct, and then proceed with your questions?

MR. FULTON: Yes, we can certainly approach it on that basis. That, of course, doesn't mean that it's correct. It's only an assumption, and --

THE CHAIRPERSON: Of course. We have had --

MR. FULTON: All right, well --

THE CHAIRPERSON: How would that sound to you, Mr. Christian?

MR. CHRISTIAN: That suits -- you know, if that's the question, assume it's correct, then I'm happy.

THE CHAIRPERSON: All right. Let's give it a try on this basis, Mr. Fulton --

MR. FULTON: All right, thank you.

THE CHAIRPERSON: -- because it's too late in the day to try with the different style of a witness aid.

MR. FULTON: All right.

MR. FULTON: Q: All right, so if you -- still looking at A2-27, and you assume that the 607-86 represents a total annual median residential bill, and the 755-68 represents the total average residential bill, on an annual basis, would you agree with me that the median customer impact based on that assumption, is for rate rider changes of .1 percent, .3 percent, half a percent, 1 percent and 1.5 percent, for each of median customers and average customers are shown at lines 41 through 53?

**Proceeding Time 3:46 a.m. T67**

MS. KURSCHNER: A: That's what is on this sheet, yes.
MR. O'RILEY: A: Yeah, I think we can assume they are calculated correctly.
MR. FULTON: Q: Right. Now, when we spoke earlier about BCUC IR 123.5.14 revised in B-26, that mentioned that 1 and a half percent benefit to the rider if there was a high cost outcome. And that shows on line 46 that it's the impact, assuming the assumptions that we've talked about, would be 76 cents monthly or $9.07 a year.
MS. KURSCHNER: A: We're comparing the impact for the 25 percent of worst outcomes here to the impact of the rate rider on a customer fail. So I guess what this is, for 25 percent of the worst outcomes over a long period of time, the deferral account rate rider would be reused by 1 and a half percent for the customer. So for the 25 percent of worst outcomes, on an annual basis, if these numbers are correct and if, you know, if my mind gets this, the annual reduction of the bill would be $11.28 on average over a long time for the 25

percent of the worst outcomes. There would be a different impact on all of the outcomes. So on any outcome that goes above the expected value, the reduction would be about 1 percent. On all the outcomes that are below the expected cost, the increase would be 1 percent.

So if I look at this, I think I would draw a conclusion from this, and I'm just trying to think really quickly here and I hope I get it right, generally over a long time the volatility of annual bill would be changing by about, say, $7. So when we have a bad year, they'd be paying $7 less. When we have a good year they'd be paying $7 more.

MR. FULTON: Q: Okay.

MR. O'RILEY: A: I'm just concerned about the principle we're applying here. Like, I think any of the costs we talk about on this panel, if you spread them over time and divide them by customers, each individual cost turns out to be nothing. But -- relatively. It's a relatively small amount. But I'm not sure that you would imply from that that the total cost doesn't matter. That seems to be where we're going with this.

Like, if I took a First Nations settlement which is amortized over many years, and talked about it spread over 1.8 million customers, it wouldn't be very much. But that doesn't mean it's not important.

MR. FULTON: Q: Could you tell us how there would be a material reduction in rate volatility as seen by a customer, if there are already deferral accounts to mitigate the changes of the costs of energy?

MS. KURSCHNER: A: Well, that is what this IR talks to. It shows the difference between the impact on the deferral accounts and the associated rate rider, with and without hedging. With the caveat that there is some assumptions here about what the short position is and what the hedging position is. But that's what this is trying to demonstrate.

**Proceeding Time 3:52 p.m. T68**

MR. FULTON: Q: Exhibit B5-1, BCUC IR 123.4. And so, B5-1, BCUC IR 123.4, and if you could also have B8-1, BCUC IR 2.126.2.

MS. KURSCHNER: A: Sorry, you said 2.1, BCUC IR 2.1 --

MR. FULTON: Q: No, BCUC IR 2.126.2, in Exhibit B8-1, and BCUC IR 1.23.4 in Exhibit B5-1.

MS. KURSCHNER: A: I have both of those.

MR. FULTON: Q: Okay. And if we start first with Exhibit B5-1, the statement in that response says:

> "The annual operational costs associated with the execution of B.C. Hydro's hedging strategy is and has been since the implementation of the CFRMP equivalent to about two FTE positions or including support

costs approximately $350,000 per year. The costs for fiscal 2009 and fiscal 2010 are expected to be similar. It should be noted that these costs are not incremental to the formal hedging program and would continue to be incurred on activities related to system optimization and energy purchasing, even if the CRMP were not in effect."

And then when you look at, next, to the response to BCUC IR 2.126.2, it says that:

"Yes, the two FTEs would continue to be needed. If the hedging program were discontinued, the staff currently carrying out the hedging function would continue to do a similar amount of market price research analysis and financial management work in support of the operations planning and energy studies modeling functions."

Can you tell us why it would be that if the hedging program was discontinued, there would be no incremental cost savings? Is it because the people would do the other work?

MS. KURSCHNER: A: Well, it's mostly because the foundation for assessing the risks that the hedging is based on is something that we need to do regardless to understand what are the risks resident in our system, and how we operate it, how we go about purchasing and so on. We have several times during today and yesterday, we have spoken about the large variability of the inputs that go into our system operation, be it inflows, market prices, loads and so on. All of those, whenever you're talking about variability, it implies risk. So, really the transactional portion of the hedging, you know, deciding what hedge to put on, is a small amount of work compared to the analytical function around assessing the risks that we have associated with our system and our short -- currently short position.

These functions are important to our operations, to our execution on the Columbia River Treaty, on pretty much everything that we do, because, you know, we -- when you look at these numbers in the application, they are based on expected values. That is the P50 probability. But there is a huge variability around those, and we need to understand that, and that is the function that these people would continue to do. It's a highly specialized knowledge that they have, and skill. It is something that comes with many years of experience and very strong quantitative analytical background, and they are fully utilized.

And I would like to add that there are also other types of work associated with risks that we are leaving right now on the table that we have not been able to get to. You know, as an example, I'd like to maybe point out that right now we do not consider the variability of Kootenay and Pond Oreille Rivers in our modeling. It's something that we wanted to do. It's -- but we have limited resources that have that skill.

**Proceeding Time 3:57 p.m. T69**

So they would be able to get some of this stuff, but at the same time I also would like to say that a lot of my staff that has these skills that work in the system automization area, they work long hours, they work a lot of overtime. This is not overtime that is charged. This is free for B.C. Hydro. And if hedging goes away, they'll be able maybe to cut back on their hours.

MR. FULTON: Q: How many hours approximately are spent annually to carry out the hedging program?

MS. KURSCHNER: A: Well, when we originally wrote this -- you know, estimated the two full-time equivalents, we looked at it from the point of view of doing all the risk -- well, not all of it, but a lot of the risk analytics, and the execution of the hedges through Powerex and the reporting and financial oversight and so on. As I explained, the reality is some of that function could be easily assigned to other, I guess,

bucket of work within my group.
So depends which way you divide it. The actual transactional piece is very small. The financial reporting, no question, the reports that we provide to BCUC on hedging, yes, that would go away. So some of it would go away but could, you know, it's not like all of a sudden we can take two people out.
MR. FULTON: Q: You need two FTEs at this point, and those two FTEs are, as I took your evidence, working extended hours in the execution of the program as well, that they're not charging for. Is that correct?
MS. KURSCHNER: A: Well, it's not like they, you know, they -- it's not like all the overtime hours are dedicated to hedging, right? They just work long hours.
MR. FULTON: Q: Can you just give us an elaboration of the transactional costs that relate to the hedging? Can you amplify on what those area?
MS. KURSCHNER: A: Yeah, we believe that the transactional costs are minimal. They would come under Powerex because Powerex is the party that executes the transaction. May or may not, as we talked about yesterday, execute the transaction in the market. It would relate to all the, you know, all the infrastructure and everything that they have in place. Given the amount of the number of our transactions, it

is literally nothing compared to the transactions that they execute.

MR. FULTON: Thank you, panel. Thank you, Madam Chair, those are my questions.

THE CHAIRPERSON: Thank you, Mr. Fulton.

Commissioner Rhodes.

COMMISSIONER RHODES: Mr. Dunlop, you were talking, I believe, about the Williston Dust Program. Was that you? Oh, sorry, Mr. Viereck. You were talking about the Williston Dust Program. And I was a little bit intrigued. I think you spent $150,000 on ineffectual measures? Is that right?

**Proceeding Time 4:01 p.m. T70**

MR. VIERECK: A: What had happened around the Williston was that people who had been working on questions of controlling soil erosion and stabilizing shorelines, had work in -- largely in southern areas of the province. And they had tried to move some of those techniques up into the northern areas. And as an example, the planting of grass in those areas. They found that, year over year, they didn't have a long enough growing season for that.

So the work that was done was an attempt to use techniques that he used in other parts of the system, applying the Williston, and they hadn't worked there. So we had to go back and take a look again at what was the

experience elsewhere in Canada and across the world.
COMMISSIONER RHODES: Yeah, because my next note is that you brought in experts from around the world. So, how many experts did you bring in, and from where?
MR. O'RILEY: A: Sure. I mean, we had six, and we did some canvassing of where people were doing this work, and we had -- I don't recall the names, and we could get the names and the credentials, but they were from places like -- a lot of them had worked in agriculture, like in Texas. There was a gentleman from the University of Guelph. There was someone from Alberta, from Olds University, Olds College. And they had -- it's a relatively small community of people that had come together at various times informally to work on different projects. There was a -- there's a very serious dust problem associated with a salt lake, like a dry lake, outside of Los Angeles, and a number of them had worked on that project, and they had worked on projects in Texas, for example, like related to, you know, dust in fields and such.
And I -- the value they were able to provide was -- they came up for about three or four days. They went to the village, the Sekey village, they went to the beaches, and they looked at what we were doing with this rye grass planting, and they suggested really three different measures in place of

the rye grass planting, which, you know, as Mr. Viereck said, hadn't really worked in the north.

This measure -- one measure was just ploughing the ground to make furrows, and it prevents the dust from being picked up in the wind. Another was irrigation in some of the areas where the dust was too fine to be ploughed up into furrows. And then the third was something we had considered as part of the water use plan, which was making more natural wetlands, so dyking areas to allow the creation of wetlands that would benefit the environment as well as keep areas wetted so there wouldn't be, you know, dust -- you know, dry earth. And they came up with a, you know, a high-level program that we then took and fleshed out into a more comprehensive plan that we tested this past winter -- or this past spring, with the -- during the dry season.

COMMISSIONER RHODES: Okay. So that was like a pre-existing team of six?

MR. O'RILEY: A: They weren't -- they were colleagues. They were -- they weren't a team, a pre-existing team. They were people that worked at different universities, and one person was retired from the U.S. Department of Agriculture, and they had in various permutations and sub-groupings had worked together on other -- they all seemed to know one another. And

they had worked on different projects in the area around the world.
COMMISSIONER RHODES: So did you, B.C. Hydro, pick the six individuals yourselves?
MR. O'RILEY: A: We canvassed -- we did, and we did that by sort of calling around through some contacts, that people made at a conference. We kind of canvassed -- it's a relatively small community of people that work in the area of dust. A lot of them had worked under one -- at different times under one professor, I believe, from the University of Guelph. So we were able to get names and put together this kind of *ad hoc* team to come and look at our problem.
COMMISSIONER RHODES: Okay. Thank you. I also had a question about the Bridge River staff housing redevelopment. That was in -- that's one of your projects, and I believe -- I don't remember what rating you gave it, but maybe an 8 or a 9 or something?

**Proceeding Time 4:06 p.m. T71**

MR. O'RILEY: A: Mr. Dunlop can speak to that, and it's probably worth talking about how we staffed that plant and some of the history of the camp there.
COMMISSIONER RHODES: Before you do that, I understand that from reading in Schedule J about this project, which is at page 8 of 120, it is a project to build

accommodation?
MR. DUNLOP: A: Yes, that's correct.
COMMISSIONER RHODES: And it has a forecast capital cost of 27 to 53 million dollars?
MR. O'RILEY: A: Yes, if the --
MR. DUNLOP: A: Go ahead, and I'll jump in.
MR. O'RILEY: A: I was going to say that that was a very early range without -- a wide range of solutions that were put forward, and I think we're well away from the high end of that range with the --
COMMISSIONER RHODES: What range are you at?
MR. O'RILEY: A: The project that's -- do you have that?
MR. DUNLOP: A: I don't have that detail. The project is in the identification phase, so as Mr. O'Riley says, this was a very high-level estimate. And work is currently going on to further define the scope of the project.
MR. O'RILEY: A: The challenge is it's a remote site that we staff four days a week, and so people come in and live. It's like a camp. And the existing housing was built probably in the fifties.
MR. DUNLOP: A: In the fifties when the --
MR. O'RILEY: A: When it was a town. It was considered a town and people lived there with their families. And a number of years ago, the families -- we moved

the families out and people -- it's just operated as a camp, and the existing housing stock is in very very poor condition. Quite a hostile environment in terms of the swings in weather and temperature and such. It is more expensive to put in replacement housing there, just because of the remoteness of the site. And we are not doing that work ourselves. We're putting that out to the market to look for solutions.

COMMISSIONER RHODES: Have you thought of other solutions? Like people commuting, that sort of thing?

MR. O'RILEY: A: It's quite a -- we have looked at that. It's not possible or safe really to drive in. What we're doing today is we're looking at a mix of a smaller number of house -- a complex that would house a smaller number of employees, and we've been using -- relying on actually a train service that ferries people back and forth to Lillooet, which is the closest town, so that avoids having to drive on the road for workers that are just there temporarily. So we're not building a lot of accommodation for temporary workers, and that's a way to get the costs down. But we are well away from making a final decision on implementation. So at that point we'll have fully canvassed the options and have a much more solid cost forecast with which to -- upon which to make the decisions.

COMMISSIONER RHODES: Thank you. Those are my questions.
THE CHAIRPERSON: Commissioner Milbourne.
COMMISSIONER MILBOURNE: I'll apologize in advance. I have a diversity of subjects. Hopefully we'll find our way through them, my handwriting notwithstanding.
Just to kind of finish up some of the extensive discussion you had with Mr. Wallace and other people about the Bernard & Company report on the Shrum problem. Could you tell me who Bernard & Company are?
MR. DUNLOP: A: Mr. Bernard has an extensive background in safety, and as Mr. O'Reilly said yesterday, B.C. Hydro has adopted Tripod Beta methodology --
COMMISSIONER MILBOURNE: I understand.
MR. DUNLOP: A: -- for the investigation of safety-related incidents. And so we wanted to apply the Tripod Beta methodology to the Unit 3 failure at GMS. We retained Mr. Bernard because of his experience with the Tripod Beta methodology.
COMMISSIONER MILBOURNE: Do you have a statement of his qualifications or anything that you could --
MR. O'RILEY: A: We could certainly get that.
MR. DUNLOP: A: We could provide that.
COMMISSIONER MILBOURNE: But as I understand it, these are methodological.
MR. O'RILEY: A: Yes.

COMMISSIONER MILBOURNE: A root cause analysis guru rather than a failure analysis, in terms of --
MR. DUNLOP: A: Yes.
COMMISSIONER MILBOURNE: -- of what I would call a failure analysis guru.
MR. DUNLOP: A: Yes.
COMMISSIONER MILBOURNE: Thank you.
MR. O'RILEY: A: And he relied on what we call the technical report for the content, if you will, of -- to describe what happened.
COMMISSIONER MILBOURNE: Okay.
MR. O'RILEY: A: He applied his methodology to that.
COMMISSIONER MILBOURNE: A couple of --
MR. CHRISTIAN: So just for the record, we will file that, those qualifications.
COMMISSIONER MILBOURNE: Thank you.

**Information Request**

COMMISSIONER MILBOURNE: A couple of questions that -- they surround the three points on page 10 of the report, and it refers to -- the discussion here that refers to the changing of -- the changed application for this particular unit. It's described here as -- unit 3 was equipped with synch condensed capability in 2005. In kind of 25 words or less, can you tell me what "synch condensed capability" is?

**Proceeding Time 4:12 p.m. T72**

MR. DUNLOP: A: Synch condensed capability really converts the generator to a motor, and Synch condensed capability is used for voltage control. So, what happens is, air pressure pushes the water in the -- to below the turbine level. The generator continues to stay connected to the system and using the exciter that's associated with the generator helps control the voltage.
COMMISSIONER MILBOURNE: So you're basically hydraulically disconnecting the turbine from the water, is that what you're telling me?
MR. DUNLOP: A: Yes, in essence.
COMMISSIONER MILBOURNE: So that's a --
MR. DUNLOP: A: The air pressure pushes the water below the turbine.
COMMISSIONER MILBOURNE: Yeah. So you're just using the generator as a condenser, basically.
MR. DUNLOP: A: Yes, exactly.
COMMISSIONER MILBOURNE: Okay, thank you. Would you describe that as a fairly fundamental alteration in the service of the unit?
MR. DUNLOP: A: We have units 1 and 2 at G.M. Shrum are equipped with synch condensed capability. Most of our large facilities have two units equipped with synch condensed capability. It assists with the operation of the system.

COMMISSIONER MILBOURNE: I'm not denying its benefits, I'm just asking if it's a change in the service application of the unit.

MR. DUNLOP: A: Yes, it is.

COMMISSIONER MILBOURNE: Thank you. Is -- down in item 3 on that page, it says:

> "The purpose was to enable 'less plant generation and maximize imports' and accept increased IPP supply."

So, do I take from that that this -- there's an element to this conversion that was to facilitate what I would describe as -- the management of the system for Powerex's trading activities?

MR. O'RILEY: A: I wouldn't say that. I mean, the increased IPP supply, for example, would be to serve domestic load. So I think what it provides is, it provides additional flexibility to the system to allow, given -- and we've talked a lot about the flexibility being eroded in general for a number of reasons. This is a way to get a little bit of that flexibility back.

And I think the important thing is, we'd actually had some fairly good experience with 1 and 2, so they were converted over a number of years previously, and we hadn't had a lot of issues, and they are the same type of generator.

COMMISSIONER MILBOURNE: Okay. In the next paragraph, it said that Mr. Bernard was unable to find evidence that the PM instructions, preventive maintenance instructions, were modified as a result of the changed operation as was required by generations RCM process. Would you kind of agree that that was the circumstances, that your protocols called for something to happen and it didn't happen? That's what it says.

MR. O'RILEY: A: Yeah, and I -- I mean, we certainly agree with the content of the report, and I think what happened -- this is a bit of speculation is, they looked at the experience they had with 1 and 2, and it was felt to be a -- not that big a change, arguably, in retrospect.

COMMISSIONER MILBOURNE: That's a bit of -- I'm being chairless. It's a bit of an assumption on your part. My next question was, was there any evidence that the maintenance instructions on 1 and 2 were modified as a result of the change, in accordance with the RCM process?

MR. DUNLOP: A: Units 1 and 2 have been equipped with synch condensed capability since they were first installed.

COMMISSIONER MILBOURNE: Okay, so that protocol wasn't in place. Okay. So this one, there was a protocol that

said you should do something and it wasn't done. That's what it says here.
MR. DUNLOP: A: Our established procedures are, when new equipment is installed, that we put in place or review the maintenance standards associated with the new equipment.
COMMISSIONER MILBOURNE: I'm sorry, this says "changed operation". Are you saying that this statement's incorrect?
MR. DUNLOP: A: I'm sorry. New equipment was installed as part of the changed operation.
COMMISSIONER MILBOURNE: Okay.
MR. DUNLOP: A: Prior to the conversation to synch condensed capability, the unit did not have any air pressure suppression capability. So it was part of the conversion to synch condense, the air depression capability was installed, and that was my reference to new equipment being installed.
COMMISSIONER MILBOURNE: So the statement is accurate.
MR. DUNLOP: A: Yes.

**Proceeding Time 4:17 p.m. T73**

COMMISSIONER MILBOURNE: Okay, thank you.
On the next page in the -- you did address parts of this table in response to earlier questioning. But I have a couple of questions on it, and Mr. Bernard again points to this, kind of in the

year 2001 to 2003 you used roughly 75 percent of the approved budget for your in-house engineering services. That's what it says. Then he notes that in 2004 the service changed from a free issue to an accounted for and budgeted service that management at the unit was now held accountable, and I guess its costs and its budget compliance and all the rest of it would reflect this allocation of internal cost. Is that the way I'm reading this correctly?
MR. DUNLOP: A: Yes, that's correct.
COMMISSIONER MILBOURNE: Okay. Does that change have anything to do with the fact that the budget as approved in 2005 drops by a factor of 10 from the year before, and that you only budgeted for 20,000 hours instead of -- or $20,000 instead of $257,000?
MR. DUNLOP: A: I'm sorry, I don't have that information. I don't know why the budget was reduced from -- in 2005 compared to 2004.
COMMISSIONER MILBOURNE: Would you agree it's kind of unusual?
MR. O'RILEY: A: Oh, it certainly is.
MR. DUNLOP: A: Absolutely.
MR. O'RILEY: A: Yeah.
COMMISSIONER MILBOURNE: You basically said, "We don't need you guys."
MR. O'RILEY: A: Yes.

COMMISSIONER MILBOURNE: Okay. And then in the year following, the two years following, 2006-2007 -- I missed one point.

In 2004 you only took up 29.6 percent of the budget, which was roughly the same as it had been in 2003. Then in 2004 the budget was basically slashed by a factor of 10. In 2005-2006, the budget was restored at a higher level with $385,000. But only 20 percent of it was actually taken up. And in 2007 it was budgeted again at a high level and only 49 percent.

Would you have any reason to believe that it was the change in accounting in conjunction with the operation of the performance management system that resulted in these changes, that it affected the behaviour, the attitude of the operating group responsible for the costs towards the use of those costs? Would that be a reasonable kind of thing to speculate on here, or to conclude from this?

MR. O'RILEY: A: I mean, that's why it's included here. It talks about the organizational change. And I would agree that --

COMMISSIONER MILBOURNE: It didn't talk about why the change. I'm asking about why the change. Why would you -- what basis would you have for explaining this kind of behaviour?

MR. O'RILEY: A: Well, I agree with you that this
change in behaviour in terms of -- and there's a
number of behaviours here. There's one that changed
in the approved amount, and the approved amount is
rated a budgeted amount, so there's an oddity there in
2005. And then there's a change in the uptake of the
approved amount in percentage in absolute terms. So
those two things. And I would agree with you that the
change in the accounting model, the change in the
organization, could have led to those two behaviours.
COMMISSIONER MILBOURNE: Okay.
MR. O'RILEY: A: So I agree with you there. I think
the connection to this failure is a bit more extended,
and the question was -- or the issue with respect to
failure is that we didn't do this shear pin failure
analysis, that it was not done. I'm not convinced
that it wasn't done because of these two behaviours
that are demonstrated here. I think it wasn't done
because they got used to these shear pins failing and
they become accustomed to them and they didn't -- it
didn't even raise a question for them that I should do
the analysis.
COMMISSIONER MILBOURNE: That's fine. I'm not going to
re-plough the ground that was already ploughed into
the number of recommendations, studies, projects and
so on that weren't put in place. I'm just -- that's

already on the record here, so there's no need for you to plough that ground again.

**Proceeding Time 4:22 p.m. T74**

MR. O'RILEY: A: Yes.

COMMISSIONER MILBOURNE: But I'm just trying to understand whether it was a climate here that leads to this kind of -- what some less charitable than I am might clarify as the neglect of the obvious. And the consequences are that there is a $60 million failure here, that was preventable, according to what's in this report. If it had had this monitoring, if this had done, if that had been done.

MR. O'RILEY: A: If they'd recognized that they should be doing the shear pin -- the analysis of the shear pin failures.

COMMISSIONER MILBOURNE: Or the monitoring -- the shear pin monitoring system, or the vibration monitoring, or the other things. I'm not going to plough that again.

I just wanted to get your views on this, what I'd call kind of -- what appears to be an organizational attitude towards its central technical resources, and it's -- and their recommendations, that was implicit here. Seemed to be -- might be implicit here.

My other question is, did -- has there been a report to your Board of Directors on this? Has there been an inquiry from the Board about this outage, this failure?

MR. O'RILEY: A: We have -- we had a report to the Board when it first happened. We sought Board approval for the repair, because it exceeded the $20 million thresholds that triggers Board approval. And that happened in -- I want to say that was at the April 30th meeting.

COMMISSIONER MILBOURNE: No, I'm talking about the root cause analysis.

MR. O'RILEY: A: They have not seen this, no. This second report was completed a week ago Friday, and I expect they would get an update on it in the November meeting.

COMMISSIONER MILBOURNE: In the -- what I, for lack of a better expression, called the real economy, the unregulated economy, most businesses, large businesses that are subject to risks from major mechanical or other systemic failures, weather-related -- risks that cause property loss and business interruptions, carry insurance against it. In order to -- because they don't have recourse to their customers to pick up the bills, and their shareholders tend to get kind of fussed when the earnings streams get adversely impacted by the unplanned or unexpected.

I'd asked some of this -- questions around

the distribution, the field office group, and they told me that this -- it's B.C. Hydro's practice to not carry that kind of insurance.
MR. O'RILEY: A: That's not correct in this instance.
COMMISSIONER MILBOURNE: Okay.
MR. O'RILEY: A: So, we have a boiler and machinery policy with a $200 million per occurrence limit, a $5 million deductible with -- and this is with Royal and Sun Alliance, and we are making a claim against that insurance policy for this amount, the amount of the damage.
COMMISSIONER MILBOURNE: Okay, and is that claim reflected and in that -- reflected anywhere in this evidentiary record?
MR. O'RILEY: A: No, it's not, no. We haven't actually made the claim yet. We were finishing the reports prior to making the claim.
COMMISSIONER MILBOURNE: So the limit of exposure to the utility's ratepayers here, you're telling me, if your claim is successful --
MR. O'RILEY: A: Yes.
COMMISSIONER MILBOURNE: -- is $5 million?
MR. O'RILEY: A: For the cost of the repair. It wouldn't cover the consequential damage, which is the increase in the cost of energy as it followed from a result.

COMMISSIONER MILBOURNE: Well, my terminology would be business interruption, which is lost revenues.
MR. O'RILEY: A: Yes. So we don't have that kind of insurance.
COMMISSIONER MILBOURNE: You do not carry business interruption insurance.
MR. O'RILEY: A: No.
COMMISSIONER MILBOURNE: Is there a reason you don't carry business interruption insurance? Because half of this $60 million --
MR. O'RILEY: A: Yes.
COMMISSIONER MILBOURNE: -- notionally is business -- what would be considered a business interruption risk.
MR. O'RILEY: A: Yeah. I'm not aware of the -- I can't answer that.
COMMISSIONER MILBOURNE: Has B.C. Hydro done any cost-benefit studies of the business case for carrying business interruption insurance against these kind of catastrophic failures, given its -- what we've heard throughout this proceeding, its aging assets and the maintenance backlogs and all the rest of it?
MR. O'RILEY: A: I'm not aware of what work we've done in that regard.
COMMISSIONER MILBOURNE: Would it -- I probably can't ask you this, but would it strike you as kind of prudent to do so?

MR. O'RILEY: A: Well, it may have been done, I'm just not aware of it, whether it's been done. The insurance in B.C. Hydro is managed in our corporate treasury group. And they regularly canvass the market in terms of what's available and what's -- you know, the various products. We have a portfolio of insurance products that tend to deal with more catastrophic risks.

**Proceeding Time 4:28 p.m. T75**

MR. CHRISTIAN: Obviously --

COMMISSIONER MILBOURNE: I don't want to pursue something and not --

MR. CHRISTIAN: Sure. I guess --

COMMISSIONER MILBOURNE: I think the question is legitimate in terms of these proceedings.

MR. CHRISTIAN: Oh, it's very legitimate and I wasn't rising to object at all. I was rising to point a way to get you some information, with respect, Commissioner Milbourne, you'd like to have. I know that Hydro has in the past, in different circumstances, considered the extent to which insurance coverage for different types of risk is available, and so it's obviously an important question.

And so what I was going to say was, you know, despite you not having asked for us to take an undertaking, maybe it would be beneficial for the Commission Panel to hear what Hydro has done in the past with respect to considering what types of insurance area available.

COMMISSIONER MILBOURNE: I would perhaps intrude, tread on your goodwill here and ask you to apply the same -- take undertaking to the question I asked the previous panel about storm damage. Because in a previous life having had a tornado at a steel mill, I can tell you that weather-related incidents can lead to some very interesting consequences, that again the shareholders would get extremely antsy about picking up the costs of. Not that you've got tornadoes in B.C., but clearly we've got other issues here that result in significant consequences, both cost and lost business.

MR. CHRISTIAN: Absolutely.

**Information Request**

COMMISSIONER MILBOURNE: Thank you.

MR. CHRISTIAN: The other observation I was going to make was that I don't believe that any of the direct costs arising from the GMS Shrum failure actually in the application has costs to be recovered in this test year. And I'm not sure if that's been made clear on the record yet or not, but I think that's something useful to bear in mind.

COMMISSIONER MILBOURNE: Okay. Those are my questions on

the report. Thank you.
THE CHAIRPERSON: Mr. Bemister, how is your court recorder doing there? Should we have a break or -- continue? Thank you. So you let us know when you need a break. Thank you.
COMMISSIONER MILBOURNE: I have some -- kind of a loose end or two that came out of the discussions with Ms. Kurschner on the interesting field that she manages. And there was extensive dialogue around this issue of managing the peaks and their curtailment programs and so on and so forth. The question that kept rattling through my mind while I was listening to that dialogue is -- you know, put it in kind of crass terms is what's so bad about having to rely on the market to meet those circumstances? It seemed like we were trying to get down to 200 gigawatt hours out of 10,000 and change, which I think is somewhere around the fourth significant digit or someplace. Like what's the matter with going to the market? Why does it -- does the world end?
MS. KURSCHNER: A: Well, I guess it comes down to does the world end if we lose some customers because we don't have enough supply. So it's a matter of acceptability of --
COMMISSIONER MILBOURNE: But excuse me.
MS. KURSCHNER: A: -- blackout to a certain amount of

customers.

Now, in terms of the market, certainly we have been going to the market. We have no other options for several years now. I guess the concern is that during the winter peak, the peak is usually coincident in all the neighbouring jurisdictions, be it Alberta or the Pacific Northwest. Usually we have the, you know, we peak in similar hours and we peak on the same days. So the challenge is or the concern is, when you are getting into that winter peak, will the supply reliably be there, and will it be there -- and beyond that. So that's the issue of reliability. And beyond there, there is an issue, of course, always the issue of economics as well. But the criteria that we have is mostly driven by reliability.

COMMISSIONER MILBOURNE: But clearly -- has there ever been an instance in the Pacific Northwest, other than some kind of cascading catastrophe, where power hasn't been available for the market, it's just been a matter of price?

**Proceeding Time 4:33 p.m. T76**

MS. KURSCHNER: A: There are times when it's challenging to secure energy. It has -- okay, so, it has never happened that we were unable to serve the peak, and we have been relying on the market in the past.

MR. O'RILEY: A: It's a relatively small sample period, because historically B.C. Hydro has had a surplus, so historically B.C. Hydro's selling capacity to other utilities in the market.
COMMISSIONER MILBOURNE: I understand that.
MR. O'RILEY: A: So, we're talking about four or five years, six years of a short position over the winter peak.
COMMISSIONER MILBOURNE: And again, I don't want to get into an LTAP debate.
MR. O'RILEY: A: Yeah.
COMMISSIONER MILBOURNE: But I mean, the province I spent a number of years in, regularly the government had to put out advisories to people to please turn down their air conditioners.
MR. O'RILEY: A: Yeah.
COMMISSIONER MILBOURNE: In the summertime, because it was summer peaking, and they didn't have the capacity, right? But it -- that was kind of the price of doing business.
MR. O'RILEY: A: Yeah.
COMMISSIONER MILBOURNE: There was no great -- the world didn't end, okay? That's --
MR. O'RILEY: A: Yes. So -- yeah. Well, I think it -- Mr. Elton described -- we take very seriously the risk of not having enough, so we would -- we wouldn't look

to Ontario as a sort of a benchmark in that regard. So that would be seen in our province as being -- or at B.C. Hydro as being a very, very difficult -- a very, very poor outcome, if we were having to do that kind of thing.

COMMISSIONER MILBOURNE: I take your point, but I would suggest to you that that -- all that is subject to a cost-benefit analysis. Is it not? It should be, if it's not.

MR. O'RILEY: A: Yes. And we don't think -- I mean, this is getting --

COMMISSIONER MILBOURNE: I'm not advocating -- I'm not advocating Ontario as a model for anything.

MR. O'RILEY: A: No.

COMMISSIONER MILBOURNE: It's just an observation, okay?

MR. O'RILEY: A: But it is actually a model we look at, but more of a cautionary tale than something to aspire to. We think we have very cost-effective approaches to meeting our peak, and the load curtailment is one program that we're very positive about. The Revelstoke 5 project is a very, very economic project that allows us to meet our peak as well as capture trade opportunities throughout the year. So --

COMMISSIONER MILBOURNE: Okay, I just wanted to make sure the world didn't end if you were -- that if on one day you couldn't make it, that you would have recourse to

the marketplace.
MR. O'RILEY: A: We certainly will have recourse to the market.
COMMISSIONER MILBOURNE: Okay, thank you.
MR. O'RILEY: A: And we have in the last few years.
COMMISSIONER MILBOURNE: My second question in that field, and this was -- Mr. Weafer got partway down this road, but he -- all he succeeded in doing was piquing my curiosity, so I've got to continue down the road at great peril, here, obviously.
When he was talking to you about the value of the resource you've got in your reservoirs, that was -- I found that kind of interesting. And my question is, do you actually value what's in your reservoirs?
MS. KURSCHNER: A: We value the marginal volume of the water.
COMMISSIONER MILBOURNE: Okay. And do you record that at the beginning of the year and the end of the year?
MS. KURSCHNER: A: No, we record that in terms of storage in the reservoirs, but not in terms of an asset.
MR. O'RILEY: A: We --
COMMISSIONER MILBOURNE: Okay, just -- maybe just before you come in, that's helpful. Again, in a previous life, I used to live next door to the largest coal-

fired generating station in North America. And their books required them to kind of value their resource. They took coal and turned it into energy, right? You take water and turn it into energy. And so the accounting rules required them to value that inventory at year-end, beginning -- and year beginning and year end, and take that into account in their financial statements.

And what intrigued me about the line of discussion was, was there any reason that that couldn't or shouldn't be done with respect to B.C. Hydro? I understand it's not done.

MR. O'RILEY: A: Yes.

MS. KURSCHNER: A: And I have to assume that -- and again, I'm not an accountant.

COMMISSIONER MILBOURNE: Neither am I.

MS. KURSCHNER: A: I have to assume that from the accounting perspective, in that case, that is an acceptable approach. The challenge with valuing the water in the reservoirs is that, unlike coal, which no matter how much amount you buy for a single plant, there is a transparent price, and you can actually go and buy it. There is nothing transparent or even currently -- we have no methodology to value the water right now that is below that marginal value of the water, because of course as the reservoirs get depleted, the value of water changes. Or, if you want to think about it the other way, as the -- you know, that the top has a certain value, but as you go down, you know, the value changes, so.

**Proceeding Time 4:38 p.m. T77**

COMMISSIONER MILBOURNE: That could be modelled though. That's just your head effect.

MS. KURSCHNER: A: No, no, it's much more complicated than that.

COMMISSIONER MILBOURNE: Okay.

MS. KURSCHNER: A: And modelling the marginal value of water is a very very complex thing to do. So I can't even begin to imagine valuing the whole reservoirs, how we would do that. So it's not like a commodity that you can buy on the market. You can't.

MR. O'RILEY: A: It has been looked at at various times at B.C. Hydro.

COMMISSIONER MILBOURNE: Okay.

MR. O'RILEY: A: Not recently. And they've always come back, from an accounting perspective, to not wanting to do it. So there's certainly an appeal to it, and -- but on balance they've always come down on the side of not doing it.

COMMISSIONER MILBOURNE: So it's an internal B.C. decision, or B.C. Hydro decision to not kind of keep the books that way?

MR. O'RILEY: A: Probably involving the auditors and others.
MS. KURSCHNER: A: Yeah.
MR. O'RILEY: A: Yeah.
COMMISSIONER MILBOURNE: Okay, thank you. I found it interesting.
In terms of the general statement, the general theme of aging assets and deteriorated condition and so on, and I think I heard the kind of metaphoric expression here today of tape and twine holding a certain power station together, which I'm not too really would reassure a whole bunch of folks. But my question again is more of a policy nature. Is there any influence outside of B.C. Hydro's management decisions that's resulted in those circumstances, that you're describing today as being the driver of this whole investment program? Is there some policy environment that's prevented you from keeping current with respect to the condition of your assets, and dealing with the known demographics of the assets, which are no different than the demographics for people, which you've seen the programs in place to deal with? But you've -- is there any influence other than Hydro's management decisions that have resulted in these circumstances?
MR. O'RILEY: A: Well, I think it -- I don't believe

there is. I think it's the result of a series of decisions made over a long period of time, and I think, because a lot of the assets were built around the same time in the late sixties and the seventies and the eighties, for many years they didn't need much -- they certainly didn't need much capital reinvested. They certainly needed, you know, maintenance.

I think another factor is we enjoyed through the nineties a period of surplus. So we had extra capacity around, so it was hard to justify an investment in reliability because you always had another unit that could pick up the slack. Especially the smaller plants. It was hard to justify reinvesting the smaller plants. And the implication of that decision, though, is that it pushed investment out, almost like a bow wave on a ship, and the size of that bow wave would grow over time.

It was also an aspect of that strategy or by-product of that strategy resulted in some very low rates over time, so there was a lot of sort of ratepayer benefit, if you will, from that kind of strategy of deferring major investment. So I think there's some micro-economic factors that led to the strategy and where we are today, and it's the confluence of some load growth in the 2000s, an adverse market in terms of the cost of and ease of executing this work that's exacerbated the crisis, or the situation. I probably shouldn't say crisis. Situation.

COMMISSIONER MILBOURNE: I don't want to fall into the trap of debating the regulatory theory, but I think some might describe what you say as people enjoyed low rates in the past as a bit of a generational inequity issue. If I get a free ride but the next guys in have to pay for the free ride I got, but that's a theoretical matter.

My question was, was there any policy influence that got us where we are, and you are saying no?

**Proceeding Time 4:43 p.m. T78**

MR. O'RILEY: A: I'm not aware of a policy influence.

COMMISSIONER MILBOURNE: Okay, that is -- thank you. In the last, is it four years, five, six years since B.C. Hydro has re-regulated, it was a period there where your rates were frozen and you were out of the jurisdiction of this Commission. Since that was changed and your revenue requirements and are coming before this Commission, has there been any material cut backs in your proposals for operating maintenance expenses as a result of these processes for which you applied for?

MR. O'RILEY: A: Well, speaking for our business group,

which I think is all we can speak for --
COMMISSIONER MILBOURNE: That is all I am asking.
MR. O'RILEY: A: Yeah. We have certainly -- so we are seeing -- for all the reasons we have talked about today, we are seeing a need to increase the spend in the business, not just on the maintenance side, but dealing with First Nations issues, and employee --
COMMISSIONER MILBOURNE: I understand. I'm back on the assets.
MR. O'RILEY: A: Yeah, on the assets. Sorry, you are talking about the assets?
COMMISSIONER MILBOURNE: Yeah, I am talking about -- I am asking you, I guess -- it's almost a negative option. This Commission hasn't said to you, that much maintenance on your assets is imprudent, we are cutting that back?
MR. O'RILEY: A: No, not at all, no that is not --
COMMISSIONER MILBOURNE: So what you came in the door with you basically went out the door with, in terms of what you asked for? Again, I am just trying to understand if it was a management choice or whether it was something else that set that.
MR. O'RILEY: A: The Commission has not mandated any changes or any reductions in maintenance, or as far as I know any capital. They have not disallowed or denied any capital CPCNs or any projects.

COMMISSIONER MILBOURNE: Okay. Thank you. Just let me check my list here.

Okay, last thing I would like to do is -- I really have got to apologize in advance, because what I have is a couple of pages of notes from going through this interesting package on the Coquitlam dam, Exhibit B-57. So I am going to use those as a bit of a guide to ask a few questions about that.

This would be a good time to take five minutes here. This would be a good time to get a five minute break. This is going to take a while.

THE CHAIRPERSON: All right, it might be a good idea if we take a five minute break, at least, because this will still take a while.

COMMISSIONER MILBOURNE: Ten.

THE CHAIRPERSON: Ten, okay.

**(PROCEEDINGS ADJOURNED AT 4:47 P.M.)**

**(PROCEEDINGS RESUMED AT 4:57 P.M.) T79/80**

THE CHAIRPERSON: Please be seated.

COMMISSIONER MILBOURNE: On the Coquitlam dam, I'm going to wander through these exhibits that are filed here in the order in which they're filed. And they're identified, like, as A-1, A-2, A-3 and so on. So I've got some kind of questions as I go through this story.

The first briefing to the Board, I think, was a project update on the 20th of August, 2003. It referred to this project reducing the generation capacity by 21 gigawatt hours per year. Could you tell me what the nameplate capacity of that station was?

MR. O'RILEY: A: The generator is a 55 megawatt facility. The project didn't reduce the generation capability by 21 gigawatt hours, the water use plan did.

COMMISSIONER MILBOURNE: Okay. Okay.

MR. O'RILEY: A: Which is an agreement to change the operation of the facility.

COMMISSIONER MILBOURNE: I take your point.

MR. O'RILEY: A: Yeah.

COMMISSIONER MILBOURNE: The elements that were outlined were 40 million for the seismic upgrades, 21 million over ten years to upgrade the Buntzen number one generating station, and 10 million for a First Nations fish ladder. Those were the three elements that were in that list.

And the statement was made that the cost if all was spent was greater than the long-term cost of new supply from other resources. And it said, "See Figure 1". There's no Figure 1 in my package, so I'd ask that that be put on the record.

MR. CHRISTIAN: Sorry, could I see where you're at? If I'm --

MR. O'RILEY: A: Yeah, it's in the second-to-last paragraph on -- we're in A-1.
COMMISSIONER MILBOURNE: Yeah.
MR. CHRISTIAN: Right. You know what? I don't see it, but I don't think it matters much.
MR. O'RILEY: A: Yeah, I've got it. I've got it.
MR. CHRISTIAN: It refers to a figure, then we'll file it, obviously.

**Information Request**

COMMISSIONER MILBOURNE: It refers to a figure, there's no figure, but --
MR. O'RILEY: A: I've got it.
COMMISSIONER MILBOURNE: And then there's a statement here, it says:

> "And the increased cost per megawatt hour requires decommissioning to be considered."

And then it goes on to say that it can't be done since the dam is intended for water users. And there's further reference to the GVRD wanting to buy the dam.

And my question is, why couldn't the dam be sold to the GVRD?
MR. O'RILEY: A: There is legislation in the province called the *Heritage Act*.
COMMISSIONER MILBOURNE: I understand that.
MR. O'RILEY: A: Which requires B.C. Hydro to maintain ownership of the dam. There was a consideration of

selling the dam to Coquitlam -- or to GVRD, but I think that was precluded by the -- by that *Act*.

COMMISSIONER MILBOURNE: I don't want to try and have a historical debate here, but you can maintain ownership and still lease the facility to somebody else for their use.

MR. O'RILEY: A: Yeah, I'm not sure what that would have achieved. I don't think there was any compelling benefit to changing the structure. Most of the water, as I understand, goes to B.C. Hydro.

COMMISSIONER MILBOURNE: Oh, okay. Well, I'll get back on my agenda, then.

The A-2 is an executive summary and a set of PowerPoint slides. And it says that the new allocation is that 62 percent of the water will go to domestic use to the GVRD and 13 percent will go to fish, and 25 percent will go to power.

**Proceeding Time 5:01 p.m. T81**

MR. O'RILEY: A: Sorry, that just contradicts what I just said, so.

COMMISSIONER MILBOURNE: I'm sorry.

MR. O'RILEY: A: That contradicts what I just said, so.

COMMISSIONER MILBOURNE: That's why I went to the next exhibit. Okay? Versus the existing situation which was that 33 percent went to domestic water and 66 percent was to your use. So when this project is

complete, it used to be two-thirds to you and one-third to the GVRD and now it's one-third to the GVRD and -- one-third to you and two-thirds to GVRD and I guess that's where this reduction in generation capacity came from. You haven't got as much water.
MR. O'RILEY: A: Yes. And the GVRD is required to pay for that water at our equivalent cost of energy.
COMMISSIONER MILBOURNE: I understand. The point is you are not the big user of the water any more.
MR. O'RILEY: A: Yes.
COMMISSIONER MILBOURNE: You're kind of a sideline. There's this comment that GVRD approached the B.C. Hydro to purchase the dam, we talked about that.
The presentation said that it was problematic to sell or give control of the asset to the GVRD under the Heritage contract and made reference to a legal view. Was that legal view obtained? Does it exist somewhere?
MR. O'RILEY: A: If it's referenced in a board document, I presume it exists.
COMMISSIONER MILBOURNE: It seems to be in as a bit of a by the way.
It says here that the proposal is funded on the notion that the new arrangement focuses on domestic needs, on the GVRD's needs while holding B.C. Hydro's ratepayers unharmed. Would you agree that the

kind of object of the exercise, was to convert the purpose, the primary purpose of the facility to serving the GVRD's water needs and holding the B.C. Hydro ratepayers unharmed against that decision?

MR. O'RILEY: A: And that's really the purpose, that was the purpose of the water use plan process. So it was to look at all the different uses of the water and the facilities including power generation. In this case drinking water, in other cases recreation, environmental values, flood control and to kind of balance all that off, and come up with an operation, an operating regime that provided more benefits to society.

COMMISSIONER MILBOURNE: Go down to A-3. The piece of it that is entitled an Executive Summary and PowerPoint Slides and this was to get approval for the funding request for the dam safety improvements. And it indicates that three options were studied, structural options where there was two of them; upstream/downstream embankments, decommissioning of the facility and the third was permanent operational modifications. So there was -- there was really four options. The other option was to give the thing to the GVRD but they said we weren't going to do that because of this legal consideration. So there is these three.

But I note that there is no cost benefit analysis of those three options in any of the materials that went to the board. The only materials that went to the board are on the downstream embankment which was management's preferred option. Is that correct?

MR. O'RILEY: A: I mean these slides went to the board, so there was discussion of the options.

**Proceeding Time 5:06 p.m. T82**

COMMISSIONER MILBOURNE: Right. But this package was provided as an undertaking to provide the materials that were given to the Board of Directors.

MR. O'RILEY: A: Yeah, and that's what these were, so the board got these executive summaries and these PowerPoint slides.

COMMISSIONER MILBOURNE: So the other three options were not subjected to a cost-benefit analysis, decommissioning, permanent operational modifications or the upstream embankment.

MR. O'RILEY: A: I would argue -- well, let's just talk about the options. So the --

COMMISSIONER MILBOURNE: No, I'm just -- I want to know if the material -- if there was a cost-benefit analysis done on those three and said, "Here's the one we prefer because."

MR. CHRISTIAN: With respect, the witnesses was going to

try and answer the question.
COMMISSIONER MILBOURNE: Sorry.
MR. CHRISTIAN: And I think, in fairness, he ought to be entitled to answer the question.
COMMISSIONER MILBOURNE: I apologize. I should let him answer.
MR. O'RILEY: A: So let's talk about the decommissioning first. The decommissioning is identified as not a viable option, so there's no benefit-cost ratio there. In very simple terms, when you put a dam into service, the community and the world kind of goes on around it, and people live on the floodplain downstream in Coquitlam and Port Coquitlam. Taking that dam out and turning that back into a natural river is not an option. So the only benefit -- the only analysis that was presented to the board was to inform them that that was not an option. That's generally the truth with these dams. There's no going back. So that's that option.
The question of the physical solution of upstream versus downstream embankment, there was a compelling advantage to one over the other. That's typically not a board decision. We would take them the recommended option and they would, you know, consider that option against the alternatives. We wouldn't typically -- where one is much better than

the other, we would take both the upstream and downstream solution to the board. The downstream solution was just way, way -- much, much better than the upstream.

The question of operating at a lower level, I believe and I'm going to struggle finding it, but I recall seeing in the business case the sort of the cost of that, of an ongoing five-metre reduction, and so it would have probably been discussed at the board. It would have been discussed at the board level.

COMMISSIONER MILBOURNE: Well, for what it's worth, I did go through all the attachments --

MR. O'RILEY: A: Okay. The two thousand --

COMMISSIONER MILBOURNE: -- what people relied. I didn't find that --

MR. O'RILEY: A: Yeah, the 2003 business case, which was written by Mr. Ken Spafford, and that would have been one of the -- probably the Bs. I believe it talked about the alternatives in more detail there. And we don't, as our practice here at B.C. Hydro, we don't typically take the detailed business cases to the board. That hasn't been the practice. We take the summaries that you see in these documents.

COMMISSIONER MILBOURNE: So it's not your practice to take the alternatives you consider and explain kind of in a pros and cons format, why you chose the one you

chose?
MR. O'RILEY: A: That is our practice.
COMMISSIONER MILBOURNE: Okay.
MR. O'RILEY: A: For example, with the example, the case you described where we talked about the option of decommissioning, the very simple overriding fact in that is it's not viable. So that's the information that the board was giving on that option.
I don't expect we would have taken them, the upstream and downstream case, because one was just so much more compelling than the other. We would have just taken the recommended physical option, which was the downstream case.
COMMISSIONER MILBOURNE: Okay. Still on A-3, on page 3 there was financial analysis.

**Proceeding Time 5:11 p.m. T83**

MR. O'RILEY: A: Of the slides you're referring to?
COMMISSIONER MILBOURNE: Yeah, I guess it is.
MR. O'RILEY: A: Yeah.
COMMISSIONER MILBOURNE: I know the page numbers, but -- and it gives the kind of conditions, and then on page 4, it shows the graph there, the chart there was a little hard to read, because it was obviously done in colours, but -- and I think it shows the relative price of energy. Is that what it shows?
MR. O'RILEY: A: Yeah, the value -- I mean, this is

hard to read without the colours, because you need the -- and we might be able to get the colours version for you. The -- my interpretation of this is that the line which starts in a downward slope, starting up near about 67, and then dipping and then going up slowly over time, is a mix of market and forward prices for -- or market and forecast prices for energy. And the various lines which start off low, the low end being the current cost of production from the Buntzen facility, and then there's a rising slope, and then a trailing-off. Those are the annual cost of generation from the plant, given different scenarios of the investment.

COMMISSIONER MILBOURNE: Okay. And that relates to the chart that was on the previous page of the table that had these net present values in it?

MR. O'RILEY: A: Yeah. The previous page, where you see a list of three -- this is page 3, at the bottom, and there's seismic upgrade 31.8, GVWD pipeline 8.2, those are just a list of -- those are just capital cost items that add up to 40.0. There's no -- there's no benefits there, it's just --

COMMISSIONER MILBOURNE: But there's a -- there's a table there with net present values in it. One line that says 2003 to 2022 and the other one says 2006 to 2022.

MR. O'RILEY: A: Yes, okay. The next slide down. At

the bottom of page 4.
COMMISSIONER MILBOURNE: And then they give -- then you give the kind of different scenarios across the top. Different kind of cost assumptions.
MR. O'RILEY: A: Yes.
COMMISSIONER MILBOURNE: At different project probability levels, different estimate probability levels. Right? You've got your P90 --
MR. O'RILEY: A: Yes.
COMMISSIONER MILBOURNE: -- and P50 costs in there. And if I look at the line that says 2003 to 2022, it's positive in all cases, right?
MR. O'RILEY: A: Yes.
COMMISSIONER MILBOURNE: If I look at the line that says 2006 - 2022, it's -- the NPV is negative under the P50 with the GVRD picking up nothing, and negative under the P90 with the GVRD picking up nothing.
MR. O'RILEY: A: Yes.
COMMISSIONER MILBOURNE: I'm reading that correctly?
MR. O'RILEY: A: That's correct.
COMMISSIONER MILBOURNE: And that's -- so that says, with an overall project cost, that where the GVRD doesn't pick up the expected share of 8.2, that the project has negative returns at the $40 million level.
MR. O'RILEY: A: Yes.
COMMISSIONER MILBOURNE: Okay, that's what it says. And

--
MR. O'RILEY: A: I'm not sure why they've got two different windows of time here.
COMMISSIONER MILBOURNE: I think it's got something to do with the service dates, but that's just a guess.
MR. O'RILEY: A: Yeah, I'm not -- yeah. But I'm not sure. It looks like --
COMMISSIONER MILBOURNE: But I'm looking at -- I'm looking at the 2006 line.
MR. O'RILEY: A: Yeah, the period prior to the thing being in service. I'm not sure why they would do that, but --
COMMISSIONER MILBOURNE: I don't -- I kind of discounted that one.
MR. O'RILEY: A: Yeah, okay.
COMMISSIONER MILBOURNE: But my question is, those numbers, the costs don't appear to include the $21 million over 10 years that's referred to in the first presentation to the Board, to upgrade the generating piece of this thing to make use of the energy. It just seems to have disappeared.
MR. O'RILEY: A: Yeah, I don't think there's any further reference to the -- I agree with you, I don't see any further reference to that $21 million.
COMMISSIONER MILBOURNE: Would you agree with me that that $10 million would make a substantive difference

to those NPVs and how negative they are? That $21 million over 10 years?

MR. O'RILEY: A: Well, a number of things have changed subsequently, so the cost of energy line that we -- or the value of energy line that we're using here changes as well. So --

**Proceeding Time 5:16 p.m. T84**

COMMISSIONER MILBOURNE: All else equal, that chart, if you included the $21 million, in that calculation, spread out over ten years, that you projected as part of this project but originally described for the board -- or B.C. Hydro did, not you, would have materially impacted those NPV dot values.

MR. O'RILEY: A: Yes.

COMMISSIONER MILBOURNE: They would have become significantly negative.

MR. O'RILEY: A: Yes. And I guess the question would be -- this was August 20 and this was October, so it was a relatively short period of time.

COMMISSIONER MILBOURNE: Yes. This is the formal request for funds, right?

MR. O'RILEY: A: Yeah.

COMMISSIONER MILBOURNE: The other was kind of a warm up.

MR. O'RILEY: A: Yes, it was the update.

COMMISSIONER MILBOURNE: Okay, so you've answered my question. Okay, and in A-4 which is an update --

well, that just confirmed that the GVRD wasn't going to pay anything.
MR. O'RILEY: A: Yes, which was always a risk. I mean when we went into this --
COMMISSIONER MILBOURNE: You had that scenario in that -- in the NPVs I accept that.
MR. O'RILEY: A: Yes.
COMMISSIONER MILBOURNE: In Exhibit A-5, it's an additional funding request as of the 26th of May, '05 which is some number of months after the first approval, right? The first approval was --
MR. O'RILEY: A: Yeah, so the May 26th item reflected the fact that we weren't getting any money from GVWD and it had an increased estimate of the capital cost and I believe it had a higher sort of risk on higher upper end risk bound. At this point we still hadn't got any market quotes, or market sort of tenders, on the actual work.
COMMISSIONER MILBOURNE: But I forget the total number of months. It's some time after the original funding approval, right? That was like in '03, wasn't it? We're not in '05.
MR. O'RILEY: A: We're now in '05. I mean this is a bit of -- this is a bit different how we would do it today. They went for board approval very very early, and I think Ms. Farrell, who was my predecessor in the

job, I think we hadn't done a lot of projects like this and I think she wanted to know that she had some support from the board for this kind of undertaking.

Our practice today would be to -- we would give updates to the board to let them know what we were thinking, but we would wait until we had much more definition around the costs, including some market -- some solid market feedback, including bids for some key equipment, before we would make the final go/no go decision. So I would -- today, the most comparable estimate that we would use to make this no/no go decision would be revision three, which is August 24/06, which is the $62 million figure, and that's informed by market quotes -- or market bids.

COMMISSIONER MILBOURNE: But -- I accept your explanation, I'll jump to that. But neither the A-5 funding request or the A-6 funding request, does it appear that the implications of those cost increases on the previously communicated "cost effectiveness" of this work, those numbers are not updated.

I guess being a person of relatively simple mind, I would assume that when you've got a project that's gone from 40 million to -- it's either 40 million or 61 million, to something up in the 60s, plus the 21 million, that this has now had a substantial impact on whether or not this thing still makes sense.

Going back to A-5 I would have -- I guess if I was sitting as a board member, I would have found it helpful to know how far down the road of commitment we were, and whether or not this might be the time to look at are we still doing the right thing?

**Proceeding Time 5:21 a.m. T85**

MR. O'RILEY: A: Sure, and I guess what I would do is I would point you to -- in A-5 I would point you to the table on page 5, where it looks at the three different alternatives, which is the decommission, the low reservoir levels, the new dam. The decommission is not an option, like for the reasons I described before. The lower reservoir levels, the key thing there is it does not fully address the dam safety risk. So this is probably our highest consequence facility. You know, 30,000 people live downstream of this. So what -- the lower reservoir levels was a shot-term mitigation. It was not a long-term solution. So what this -- this new dam was driven, this is really the only practical alternative here.

COMMISSIONER MILBOURNE: I'm sorry --

MR. O'RILEY: A: This is not a financial investment intended to produce a revenue stream or -- this is --

COMMISSIONER MILBOURNE: I'm sorry, I do want to put -- I'd like to question one of your comments. You say the lower -- the modified operating practice was not a permanent solution. It's described here as permanent modifications. Permanent, not transient.

MR. O'RILEY: A: Yes, and on page --

COMMISSIONER MILBOURNE: And I would take from that that that addresses the safety risk.

MR. O'RILEY: A: In page 5 it says under "lower reservoir levels", in the first bullet it says "does not fully address dam safety risk". So it might be the lowest-cost solution but it's not the solution that addresses the dam safety risk. And that risk is so great compared to all the other determinations, it was the overriding factor in this decision, was dealing with that dam safety risk.

So in the end this wasn't a decision that turned on a net present value or -- I mean, that's why the question of the cost of production at the $21 million at Buntzen fell away, because it's not a factor any more. It's how do we keep the people downstream of the dam safe for the long term, because there's 30,000 people that live there.

COMMISSIONER MILBOURNE: I don't want to get into an argument, argumentative position here, but one might have thought that if B.C. Hydro management had determined that the cost of generating the energy was so far out of line with what was reasonable as a result of the increasing cost here, that one might have said, "Okay, could we not now have a new negotiating position?" And since we're dealing here with a dam safety risk, two-thirds of the water behind that dam is going to be to the benefit of the GVRD water users, not to the -- nothing to do with the ratepayers any more, that we might be able now to strike a deal where we give up our little bit of generation, which is not material in terms of your overall provincial capacity, and cut a deal that sees the GVRD pick up the cost of rendering a facility they're the primary user of, seismically safe.

And I realize I'm second-guessing here, but I'm posing it as a reasonable outcome for what's happening.

MR. O'RILEY: A: Sure. And the challenge with that is we -- the responsible for the dam safety risk resides with B.C. Hydro. We have the responsibility to our regulator, the controller of water rights, which is within the Ministry of Environment in the province. They look to us. They're not looking to GVRD. The GVRD are just tenants. So we have no leverage. We had no leverage in this entire engagement with GVRD to make them do anything except pay for the power that they were going to take at the marginal value of -- you know, the equivalent power value. We had absolutely no leverage in this with GVRD. The responsibility fell back to B.C. Hydro to deal with this situation.

COMMISSIONER MILBOURNE: I hear what you're saying and I have no argument with what you say. I just don't see any of that reflected in any of the materials that were presented to the board, or any of the decision making that's there.

MR. O'RILEY: A: Well, I mean, I would point back to the relationship with GVWD, the presentation that went to -- you know, that went back to -- in October, 2003. And, I mean, the way these things work is, there would have been extensive discussion of all of these things at the Board meeting. Our negotiating position with GVWD was the subject of a lot of discussion in the meetings that I was part of. I wasn't part of all of them, but --

**Proceeding Time 5:26 p.m. T86**

COMMISSIONER MILBOURNE: The discussion with the GVRD about why they wouldn't pay their 8.2 million was clearly well documented. That's the only piece of the discussion with GVRD that has any level of documentation here.

MR. O'RILEY: A: And what I'm saying is, I -- I mean, I guess we considered it a given that the dam safety responsibility was -- fell with B.C. Hydro. We didn't

see a way to just hand that responsibility over to GVWD. We're the ones with the statutory responsibility to the -- to control our water.
COMMISSIONER MILBOURNE: I realize I'm getting into an argumentative mode, and I don't want to be there. The GVRD wanted to buy this thing.
MR. O'RILEY: A: There was some discussion with GVWD about buying it. I don't think they were that keen on buying it. And they certainly weren't going to buy it before it was fixed. They didn't want to buy a used dam, and a hundred-year-old used dam. Because that's what we're talking about here. A hundred-year-old used dam with 30,000 people living downstream.
COMMISSIONER MILBOURNE: I'm just looking for the -- kind of verify the record.
MR. O'RILEY: A: Yeah.
COMMISSIONER MILBOURNE: The GVRD had approached B.C. Hydro about taking ownership or control of this facility. Is that correct?
MR. O'RILEY: A: There was some discussion with GVWD about the water district about that, but it -- as far as I know -- well, I know it didn't come to anything. We weren't able to strike a deal there. And there was this issue with the *Heritage Act* that requires B.C. Hydro to own the facility.
COMMISSIONER MILBOURNE: The record of dialogue with the

Board kind of finishes up -- where is it? A-8, A-9, A-10. The last interaction was the 31st of October, 2007. My question is, what was the final cost of this project?
MR. O'RILEY: A: The final cost was 65.6. It was done at P90, so we did not require a subsequent approval.
COMMISSIONER MILBOURNE: Okay. And is the -- that 21-point -- 21 million over ten years still going to have to be spent?
MR. O'RILEY: A: We haven't updated the -- well, there is some need to re-invest in Lake Buntzen 1. We've currently got a project underway. We've had to reintroduce it. It was previously deferred, but we've had to reintroduce the project to replace the runner. There will be some other investments required, but we're not going to redevelop the plant, that this option -- we'll just keep running it. It's -- you know, it's a lower priority for us. I don't expect we're going to be paying $21 million, spending $21 million for the foreseeable future.
COMMISSIONER MILBOURNE: Do you have an estimate?
MR. O'RILEY: A: We're spending, I believe -- do you have the number for the runner?
COMMISSIONER MILBOURNE: I'm going to ask you to do something here, so maybe you can do it that -- what I'm going to ask you to do, if it's not too much

trouble, is to update that chart on relative energy costs and the NPV calculations on an as-built basis with adding in the -- whatever it is that you think you're going to be spending on Buntzen.

So you've got 65.6 million plus something -- cut a few million dollars, I don't know, that you've got to spend on Buntzen. That if you've got to stop generating here, you wouldn't have had to spend that money.

**Proceeding Time 5:31 p.m. T87**

MR. O'RILEY: A: Well, again, back to my previous point, I don't think that was an option.

COMMISSIONER MILBOURNE: No, no, but I just say that you may not be able to escape the dam thing, but you didn't have to do a bunch of other -- I don't know. I just ask if you can do that.

MR. CHRISTIAN: Sorry, can I just get clear in my mind which table? It's the one that was underneath the board presentation that had the numerical analysis for the different options, the net present value under the table that --

MR. O'RILEY: A: It's page 4, A-3. A-3, page 4 in the slides.

COMMISSIONER MILBOURNE: Yes. Just to see what it looks like.

MR. O'RILEY: A: What it turned out.

MR. CHRISTIAN: And the update would be with respect to the currently anticipated cost with respect to the generating unit that was the subject of exchange between Mr. O'Riley and Mr. Dunlop and to build in those costs into that analysis to see what the net present value would be, and would that include presumably the value of the -- I don't know if there any incremental generation, but I guess I'm trying to struggle with just adding in the dollars may not get to a realistic type of update unless value of energy arising from that investment and generation is also taken into account, and that's the part, I'm sorry, in my own mind about whether that can be done.
COMMISSIONER MILBOURNE: That's why I asked you about the other chart. It shows the value of the energy relative to --
MR. O'RILEY: A: And that would be much higher today than the numbers we had in the --
COMMISSIONER MILBOURNE: Yeah, I know that whole thing would change. I just wanted to see how this thing still fit together.
MR. O'RILEY: A: Panned out, yeah.
MR. CHRISTIAN: So I think, as I understand it, it's possible, but I want to make sure it actually can be done before I commit to doing it.
MR. O'RILEY: A: I believe it can be done. It's

reasonable.
MR. CHRISTIAN: Okay, so we'll do that.

**Information Request**

COMMISSIONER MILBOURNE: I wouldn't ask you to do something you couldn't do.
MR. CHRISTIAN: Oh, indeed, I wouldn't agree that we could do something we wouldn't do. Or other way around.
COMMISSIONER MILBOURNE: My final question on this is has there been a post project evaluation of this? I noticed in one of these sessions with the board and members asked for -- the management undertook to start doing these post-project reviews. Has there been one done on this and has --
MR. O'RILEY: A: We have a policy requirement to do post expenditure reviews and that will be done. We just finished the -- we just had the ribbon cutting not that long ago.
COMMISSIONER MILBOURNE: Sometimes the ribbon cuttings are quite a bit after the cake comes out of the oven.
MR. O'RILEY: A: Yes. So we will certainly be doing one of those.
COMMISSIONER MILBOURNE: Okay, but you haven't done one yet.
MR. O'RILEY: A: Yeah, in general, yes, we are very very happy with how this project unfolded. The most

important things with a dam like this, because it lasts for so long, is that it be built well and the quality was very very high. It's a very difficult construction process because there's only really three months of the year you can actually build this kind of thing, because it needs to be dry. In the end it took a little longer than we would have liked, but given the tight construction season, we are happy with the results.

COMMISSIONER MILBOURNE: I'm sure the GVRD are as well.

MR. O'RILEY: A: I'm sure they are.

COMMISSIONER MILBOURNE: I'll leave it at that.

Thank you for your good humour and cooperation. I appreciate it.

MR. O'RILEY: A: You're welcome.

COMMISSIONER RHODES: I just have one other matter that I wanted to ask you about, and that is the Shrum failure. There is some IRs on it and I don't think you necessarily need to refer to them, but in your evidentiary update and the IRs you estimate the cost to repair it is between 24 and 28 million.

MR. O'RILEY: A: Yes.

**Proceeding Time 5:35 p.m. T88**

COMMISSIONER RHODES: And then the loss of gigawatt hours you estimate to be 2,000 based on the 320 days that it probably would have been in duration, except that it's not. And then finally, you estimate the net impact on the cost of energy, including both increased cost of purchases and decreased revenues, to be $30 million. And I'm just wondering how you came up with the $30 million, like what was the analysis?

MR. O'RILEY: A: Ms. Kurschner can speak to the details around that because it would have been done in her group. In general, we're not spilling the water past the plant, so we still have the water to generate with. We're just generating at a less opportune time, so we don't have as much ability to generate over the peaks, and so we're forced to generate in lower value periods. So it's displacing -- it's causing us to purchase at more expensive times. It's reducing our ability to purchase at lower price times. And all told, when you run that through the models and look at all the variability and prices and hydro conditions, then net increased cost is $30 million and that spreads over a couple of years.

COMMISSIONER RHODES: But it's only going to be out of service for one?

MR. O'RILEY: A: The impacts are felt because you're pushing -- you're taking water you would have generated this year when we had some fairly high prices, particularly in March and April, and you're putting some of that water into next year. So that's

why the impacts are felt over multiple years.
COMMISSIONER RHODES: Can you provide some of the assumptions, like it seems like a very general number and I understand that you've put it through something to come out with it. But I mean, you do have, like, other places you can get power from in the system. You have other methods of getting power.
MR. O'RILEY: A: Yes.
COMMISSIONER RHODES: And to the extent that you would have sold it to Powerex, and Powerex would have made money from it, that's more than 2 million and that wouldn't be anything to do with Hydro any more. That would be the government, that sort of thing?
MS. KURSCHNER: A: It's the optimization proposition. So if you recall, I said we optimize the system over a long period. So the fact that all of a sudden you've got less capacity to generate from Peace means not only that you have a little bit more trapped water, it means that in certain times, and this year was unfortunately a really bad year for this to happen because we were short energy, and the market was extremely high during that time, and this persisted throughout, you know, I'd say late February, March, April and first few days of May before the market actually softened and we were able to purchase at the cheaper prices. So the fact we had water, we just

couldn't generate enough. So we were short. So that would -- so there was trapped water that we had to replace through higher purchases.

And then of course anything going forward now has changed because all of a sudden the reservoir is higher. So you're in a situation where later on you have to operate it a little bit differently. There might be purchases that you otherwise would have been able to take in to the system that you now cannot. So it kind of cascades into the longer term through the optimization.

So it is not a simple matter of, you know, Powerex couldn't trade more. It represents itself throughout the longer period, by the fact that we couldn't generate from the water that we had in storage. And we needed it.

**Proceeding Time 5:39 p.m. T89**

COMMISSIONER RHODES: Is there a way that you could, like, show the calculations?

MS. KURSCHNER: A: Yeah, we could.

COMMISSIONER RHODES: Okay.

MS. KURSCHNER: A: Can you tell me, just from the IR, what the date was on the IR when we submitted that one?

COMMISSIONER RHODES: Yeah, it's IR --

MS. KURSCHNER: A: It's in the box up top.

MR. O'RILEY: A: We have it in the update.
MS. KURSCHNER: A: The date.
COMMISSIONER RHODES: Yeah, it's IR 3 --
MR. O'RILEY: A: Just give us the number.
COMMISSIONER RHODES: 3-1-86 3.1, and it's to BCUC, July the 9th of 2008.
MS. KURSCHNER: A: Yeah, and of course, you know, that would have been done about the time when prices going forward were extremely high. So, but we -- so what we can do is, we'll go back and we'll find the assumptions, we'll figure out what we based it on and we'll tell you that. No problem.
COMMISSIONER RHODES: Thank you very much. That's what I would like to know. Thank you.
MR. CHRISTIAN: And just for the record, we will provide that undertaking response.

**Information Request**

MR. O'RILEY: A: That's the lawyer's job.
THE CHAIRPERSON: Mr. Eldridge, earlier you had conversation with Mr. Fulton regarding one of your productivity initiatives, which was that capital improvement process, where you are trying to improve your process base when it comes to project management and reporting and what -- I presume, estimating as well. And you are spending -- and systems also. IT work, and you are planning to spend significant

dollars.
Are you in touch at all with BCTC? Because you know, they are doing a lot of work in this area and spending significant dollars as well in the same area.
MR. O'RILEY: A: I can probably speak to that. So, we are working with -- we're partnering with BCTC on the capital procurement or capital project execution initiatives, as they relate to transmission. They've got a -- BCTC has hired a consultant and there's five or six areas that they're focusing on, including estimating project controls, the sort of roles and accountabilities between BCTC and B.C. Hydro with respect to project managers and initiators and such. So we're working very closely with them on that front, and we're bringing back the learning from that into our -- the generation side of our business. So we're definitely tied into BCTC on that front.
THE CHAIRPERSON: I'm pleased to hear that, because clearly ultimately most of the ratepayers are the same group, and --
MR. O'RILEY: A: They're the same, yes.
THE CHAIRPERSON: -- you have to avoid duplication there.
Again, I'm still staying with BCTC. Now, you are providing engineering services to BCTC and there's agreement and it's your responsibility to

provide those services. So is there expiry date to this first agreement?

**Proceeding Time 5:42 p.m. T90**

MR. O'RILEY: A: The service agreement had a -- I had this written down and I didn't bring it. Had a ten-year life starting in 2005 and there's a reference volume defined which was 46.1 million of engineering services, and they had the option, with two years notice as of last April to reduce that amount by 20 percent per year. So after five years there would be nothing left, and then they could go to market for all of their services.

They've made a decision that they want B.C. Hydro engineering as a strategic partner for a portion of their work which is in excess of the minimum volume of 46.2 million, and we are renegotiating the service agreement with them on that basis, and we expect to have that done by the end of March. So that agreement won't have the reduction provisions, and they will continue to put a significant proportion of the work out to market as they've done, for example, with SNC Lavelin.

THE CHAIRPERSON: So then if I understand you correctly, rather than taking advantage of the first 20 percent, they have not exercised that. In fact they want you to do more work.

MR. O'RILEY: A: Yes. They found -- I mean the way the market has unfolded for engineering services, they've seen a tremendous advantage to having access to the B.C. Hydro engineering group, and they've also found that when they are using consultants, that there is a role for a quote/unquote owner's engineer, where part of this agreement will to be to specify layouts and expectations for that role to help BCTC manage the contractors. And that's certainly something we've found on the generation side, is when you do contract out big chunks of work as we've done with our spillway gates to hatch energy, there is a significant requirement to manage and oversee that engineering work.

THE CHAIRPERSON: Like considering already your own resource challenges at B.C. Hydro, then you are confident that you are able to continue to manage both?

MR. O'RILEY: A: Yes. So we are confident -- as I said again, we pretty much segregate the resources between GT&D and so we are confident with the transmission engineering resources that we have, that we'll be able to do a mix of this owner's role for BCTC and some execution of work for BCTC.

**Proceeding Time 5:45 p.m. T91**

THE CHAIRPERSON: Okay, thank you.

My next question is very much just a follow-up and clarification of all these discussions on $60 million expenditures. That seems pretty trivial but it's more of the principle. And that was the BCOAPO -- your response to the BCOAPO IR 1.17(d) which was in the Exhibit B-5.

MR. ELDRIDGE: A: I have that.

THE CHAIRPERSON: And that was the reconciliation reasons for the additional expenses. And before already we went through that. There was the engineering net recoveries, the $5.6 million, which was explained primarily linked to the increasing capital programs. And the other one was the project delivery 2.7 and that was increased project management hires to meet larger capital plan and also -- I also noted very much, I think it was Mr. O'Riley's comment talk about, in quotes, "sustained increase in capital work" --

MR. O'RILEY: A: Yes.

THE CHAIRPERSON: -- which means that it will continue to happen. It's not just these two test years. And then the third item, the capital overhead, there is a reduction $1.7 million additional transfers to capital. And just looking at this incremental reconciliation, the $1.7 million is only about 20 percent of these two other items, if you add them together, which both sounded almost 100 percent related to capital, and I presume that you are using your existing allocation methodology, how you transferred cost to capital.

So my question is, is it time to review that methodology, with these changes happening, that are you really following this current methodology? Is it working in today's environment on this sustained, continuous sustained increase in capital work?

MR. ELDRIDGE: A: Well, you're absolutely right. If the model was working perfectly, if you had an increase in support cost of capital, it would all flow to your capital overhead.

THE CHAIRPERSON: That's right.

MR. ELDRIDGE: A: And the way we do our capital overhead, because in the end it's just an allocation of operating cost to capital. And when we look at it we look at it at the beginning at the year, and we look forward to say -- and we estimate how much of our activities will be devoted to capital for support, support costs. And we set capital overhead and we don't change it as we move through the year. So it's almost a fixed allocation.

As we move through the year and we hire significantly more in either engineering or project delivery, there is the potential for a disconnect in that your capital overhead which is fixed may not be sufficient to capture the actual increase in your project delivery and in your engineering resources.

So we saw that in fiscal '08 where we were hiring significantly higher than was expected, and we really -- we true up every year.

**Proceeding Time 5:49 p.m. T92**

So every year, when we re-plan our support cost and our direct capital costs, we would true up that capital overhead. So, for fiscals '09 and '10, we have made an assumption as to -- in these capital delivery groups, how much will go directly to capital, how much will be in support. We calculate capital overhead accordingly. If any decrease or increase in that level of support costs in actual, won't be captured.

So I think the variance you very rightly see is that the model is a static one at the beginning of any year, and it doesn't capture the actual changes as you move through the year.

THE CHAIRPERSON: So you will require true up at the end, then.

MR. ELDRIDGE: A: You do. And the true-up will be perspective, not retrospective.

THE CHAIRPERSON: Okay. Right. How about the situation, now, and that's how it works in your system. But now, we are dealing with the revenues -- revenue requirement application, and we have two test years. And the rates that this panel will be deliberating on will be based on this application. So there is no chance to reflect on the results of your true-up, after the years actually are done.

So, how can we deal with that?

MR. ELDRIDGE: A: Yeah. And I think it's looking to the support costs that we have allocated to capital in plan, and determining the reasonableness of that allocation. If -- we certainly saw in this year that we spent more on capital support than expected, and the cost --

THE CHAIRPERSON: This year meaning --

MR. ELDRIDGE: A: -- fiscal '08, I apologize. So, the last year.

THE CHAIRPERSON: Yeah.

MR. ELDRIDGE: A: The cost of that was absorbed by B.C. Hydro. If we are in the circumstance where our plan of capital support cost is less than expected, that would be to the benefit of the shareholder or the company. But there are ups and downs, and the capital overhead that you do see is significantly increased in '09 and '10, and again it's directly tied to the FTEs that you would have reviewed earlier on, and reflective of some of the increases that you see in this IR. So I hope that --

MR. O'RILEY: A: I guess the question I would just want to make sure is that you have enough information --
THE CHAIRPERSON: Exactly.
MR. O'RILEY: A: -- to understand the assumptions we've made, and --
THE CHAIRPERSON: Well, I think I understand now that -- I have tried to understand how this -- you have a methodology that works, but just looking at these numbers again, I don't have a comfort level that for these two test years you are transferring enough to capital to overhead, that the ratepayers are paying in current year cost for 2009 and F2010 more than they should. That's my concern.

**Proceeding Time 5:52 p.m. T93**

MR. ELDRIDGE: A: There is an IR that breaks down the capital overhead so it looks at all the support costs and how much of those supports costs are allocated to capital. It's BCUC 1.4.47.3. and just as an example, it would show the total support costs that are the subject of the allocation, the percentage of that allocation.
So again it's an example in fiscal '09, it shows that we have a total support cost pool of $90 million. We are allocating again in '09 42 percent of that to capital.
THE CHAIRPERSON: So how does that compare to F2008?

MR. ELDRIDGE: A: F2008 we would have allocated 39 percent of our support cost to capital.
THE CHAIRPERSON: Okay, so you get the percentages going up.
MR. ELDRIDGE: A: The percentage went up and also the pool of support costs went up as well.
THE CHAIRPERSON: Right, okay.
MR. ELDRIDGE: A: So you've got both of those factors.
THE CHAIRPERSON: And so you are reviewing this annually?
MR. ELDRIDGE: A: We are.
THE CHAIRPERSON: Okay, thank you. Perhaps -- I think this is my last question just to finish off with this, and again I think, Mr. O'Riley, you already had -- I think you started with Mr. Fulton and you carried on the dialogue with Commissioner Milbourne, but your engineering services area so. First the -- I know we have the total staffing numbers for your group, but how big is the staff complement in your engineering group.
MR. O'RILEY: A: The engineering group, I'll just give you the number as of August. And it's tied to an IR, that's why I prefer to use it.
So as of August 31, our head count in engineering was 711.
THE CHAIRPERSON: 711, okay. And would that group then -- so by way of a high-level summary, how would you

describe your current model of delivering engineering services? You alluded to using other companies to some degree, but would you try to explain what really is your model.

MR. O'RILEY: A: Sure. I'll try, and if I'm not getting there perhaps you can redirect me. It's different for GT&D for various circumstances. So for the transmission we're providing services as requested, really, from BCTC. So that could be project management services, it could be design services, it could be -- sometimes it's full project implementation from early definition through implementation.

THE CHAIRPERSON: Yes.

MR. O'RILEY: A: And sometimes it's just early definition work. So when we were proceeding with northwest transmission line, before that project was terminated or cancelled, we were just planning on doing the early definition work, and then they were going to put that out to a design build or a P3 type product.

**Proceeding Time 5:56 p.m. T94**

THE CHAIRPERSON: Okay.

MR. O'RILEY: A: So it really depends on what they want.

For Distribution, we look after the larger projects for distribution. So the RAV Line projects for example, the interconnection of the RAV line stations. Some of the Olympic venues, we're managing those as projects. And we provide a project manager and designers and such who will do the design and create packages of work that we hand back to Field Operations to implement, either with their own resources or with contractors. But we're definitely working for Field Operations as sort of the owners, if you will, of the equipment.

On the Generation side, what we've done is we've pulled out -- we did this when we set up the EARG Group. We pulled out the project management division to provide greater focus around project management. And so the engineering provide -- they provide project services whether they're designed services or estimating or contract management or construction management services to individual projects. And they provide a portion of the services. About 80 percent come from our own engineering people, and we use about 20 percent external contractors, and they are managed through the projects. And I should say all of this is talking about projects and capital, which is the biggest part of our engineering work.

There is a portion of our engineering work that's focused on maintenance, and we have maintenance staff in all three groups that are -- you know, we talked about the generation engineering maintenance services that provide services to the field in Generation, and we have similar services in Transmission and Distribution.

**Proceeding Time 5:58 p.m. T95**

I think the other thing I would say is we had a number of years ago started to conceive of B.C. Hydro engineering as something that could be kind of set aside within the company, and that could compete with private sector in getting business outside the company. And I think the point I've tried to make today is, we've really pulled back from that. We see the prime focus of engineering as providing service within the company or to BCTC. And any third-party work would be incidental, almost, to the -- very much being the exception.

THE CHAIRPERSON: Well, how about the opposite, where you would consider reducing the size of your engineering group and increasing significantly amount of outsourcing to engineering firms?

MR. O'RILEY: A: We are, in our -- we are forecasting as the capital grows to significantly increase the percentage of work that's done by consultants or contractors. I should say that, on -- with a lot of the work we're doing, we're not doing detailed engineering. So with Revelstoke, when we buy a turbine generator, we just provide them high-level specifications and effectively all that design work is outsourced to the manufacturing firm. So over and above the 20 percent figure I provided, we are outsourcing even more as part of the parcels of equipment we're buying.

What we've found in the last few years is that the market for engineering services is quite challenging, given the amount of infrastructure investment that's going on. There is -- you know, it's tough to get good contractors, and it's -- there's quite an effort to kind of oversee them. And as we've found, they are quite expensive as well. And a lot of the work we do is quite specialized, so there's certain things -- certain areas where it works really well to go outside, and I would -- I talked earlier about the Fort Nelson upgrade there, which is very much something -- we don't have a lot of experience in thermal, so that's something that's very easy to go outside in terms of project management and, you know, equipment design. All that's getting pushed out for, you know, some of the more esoteric work we do and the more Brownfield development work we do, it's a little harder to push that out. But we are trying to stretch in various ways our approaches to procurement.

**Proceeding Time 6:01 p.m. T96**

THE CHAIRPERSON: Now, assuming that those services would be then more readily available, have you recently done sort of this market pricing comparative, assuming your engineering services would have to competitively bid for a project within B.C. Hydro?

MR. O'RILEY: A: Yeah, we --

THE CHAIRPERSON: And are you competitive? Looking at it here from the ratepayer interest perspective.

MR. O'RILEY: A: We are, and we have some data on that as part of this discussion we had about how we price our services to third parties. And certainly on a per unit basis, our services, even when you add in a lot of overhead or allowances for overhead, we come in under. I know that's not the full picture because you're making a different commitment to an employee than you are to an hourly engineering --

THE CHAIRPERSON: Over the last two weeks we have heard a lot about that, you know.

MR. O'RILEY: A: Yeah, yeah. That's certainly -- certainly an issue.

THE CHAIRPERSON: Are you comparing apples and applies in that assessment?

MR. O'RILEY: A: Yeah. I guess when I think of this broader question of contracting, whether we do work in-house or whether we do work outside, it starts with the nature of the work and the profile of the work, the need for the work, the ability to defer it. Is it a short-term need or a long-term need? Then I would ask the question do we have the capability in-house? Is that expertise resident here? If it's not, do we need to develop it or can it be readily accessed in the market? And then the third question would be do we have the capacity, do we have the ability to handle the volume? And we come down on different types of work, we come down on different sides of that equation

So if I talk about our water licence requirement, which is a very significant increase in our work volumes, much of that work is environmental, very technical environmental studies and sort of probably lower-end civil work, like boat launches and that kind of thing. We don't have the capability to do those environmental studies in-house, so we're putting all that out to the market. And we don't have the desire to do the low-end civil work in house and that's readily available in the market.

**Proceeding Time 6:03 p.m. T97**

So virtually all the water licence execution is being outsourced and all we are doing is a little bit of management of all these contracts and a bit of interpretation of the results and acceptance of the end product.

Other examples, the spillway gates work, which is a lot of mechanical and electrical work. We have some capability in house. We don't have enough capability. We have the capability in house, we don't have enough capacity so we've outsourced that as a package, and again, we are just managing the contracts and the projects and that's working out fairly well.

And then another example I talked about earlier, Aberfeldie, we've outsourced the engineering work in a major design contract. So there's different approaches depending on, really, the answers to those three questions.

THE CHAIRPERSON: Thank you. Those are my questions.

So any re-direct, Mr. Christian?

MR. CHRISTIAN: I do. I'm sure people are hopeful that I don't have a lot. And I can confirm that I don't have a lot.

**RE-EXAMINATION BY MR. CHRISTIAN:**

MR. CHRISTIAN: Q: The first one, I think it's for you, Mr. O'Riley. It arises from some questions, I believe put to you by Mr. Fulton earlier today with respect to stage 3 Site C costs, and can you clarify for the record whether or not there's been a decision made to proceed with stage 3 of the Site C work?

MR. O'RILEY: A: There has been no decision to proceed to stage 3 of that work, and that decision would ultimately be made by the province, not B.C. Hydro.

MR. CHRISTIAN: Q: Thank you. And then my next little bit of re-examination arises from the transcript at Volume 12, and this was an examination of you, Mr. Viereck by Mr. Wallace. And on the top of page 2077 you made a statement there and it reads:

"So the totality of a settlement would include both issues that B.C. Hydro has and as well as the province."

Are you or Mr. O'Riley, as appropriate, able to elaborate on what you meant by that statement?

MR. VIERECK: A: The statement really goes back to the origins in terms of the acclaim or action that the First Nation takes, which is a claim or action with respect to our reservoirs or our dams or our transmission facilities and claims of damage of destroyed property, of destroyed villages, of destruction of hunting and habitat of the first Nations. So that's the general context of the action.

**Proceeding Time 6:06 p.m. T98**

Where B.C. Hydro decides that there is appropriate steps to take in terms of trying to resolve those matters through negotiations, part of that is an exercise of due diligence, and what we go through is, we look at all of the permits, tenures, certificates and other authorizations that were given to B.C. Hydro in the construction, building, flooding and operation of our reservoirs, dams and transmission sites. So those are what we, in the negotiations, secure, in terms of certainty of all of those operations -- or all of those authorizations.

And in terms of what we asked for, as a general practice, if we are to settle this particular matter, we ask that the First Nation releases B.C. Hydro or any other party that may have been involved in terms of the issuing of our ability to build and operate the facilities. The intent of that is that, in securing a settlement, that the First Nations cannot go back after other parties in terms of our ability to operate our facilities.

MR. O'RILEY: A: And if I can just add, what we're concerned about with respect to the province is the First Nations going back to the province and, through that back door, being -- causing our permits to be at risk. So that's why we seek the resolution claims against the province and B.C. Hydro, because we don't want to lose our claims through a back door. And it's important to remember that all of those permits enabled the construction and operation of those facilities, which have provided benefits to ratepayers for many years in the past and will provide in the

future.
MR. CHRISTIAN: Q: Thank you. And moving down on that same page, there was a question from Mr. Wallace asking whether that has been formalized in a document between the province and Hydro. And Mr. Viereck, you answered there are submissions that have been made to Treasury Board and Cabinet. And then without getting on the record whether -- who has possession of those documents, I agreed that we would provide copies to the extent we could, subject to any kind of legal privilege.

Can you confirm, or explain, whether or not those documents are documents that Hydro has, those ones that you were referring to in lines 11 and 12?
MR. VIERECK: A: Hydro does not have possession of those documents.
MR. CHRISTIAN: Right, and so, further to our earlier conversation today about requiring B.C. Hydro to do things it couldn't do, I guess I'd like to formally seek leave to relieve B.C. Hydro of the undertaking to provide a document that it doesn't have. I assume that's a formality.
THE CHAIRPERSON: Leave granted.
MR. CHRISTIAN: Thank you.

**Proceeding Time 6:10 p.m. T99**

MR. CHRISTIAN: Q And then lastly, the last topic of my re-examination also arises from Volume 12 of the proceedings, and that -- there was an exchange between Mr. Wallace and Mr. O'Riley, starting at the bottom of page 1997. Again, that's Volume 12, page 1997, and Mr. Wallace asking Mr. O'Riley about two of the key influences that were described in the application, and the effect on the cost structure of the EARG business unit. And the two particular key influences referred to by Mr. Wallace were aging infrastructure and capacity constraints, and that's on lines 22 and 23. And I'm wondering whether you can comment on whether or not any of the other key influences have had an impact on EARG's cost structure.

MR. O'RILEY: A: Yeah.

MR. CHRISTIAN: Q: And just before you answer, just so for the record at least, the key influences I'm referring to are on page 1-4 of the application.

MR. O'RILEY: A: Yes, we stopped after the first two, but the third being labour market pressures, and that is impacting the cost of equipment for capital projects, and an example being the recent increase in the wages for boilermakers who are doing welding on Revelstoke 5. We're also seeing a need for increased training and development costs for new employees as we tap into new hires for B.C. Hydro.

The fourth item was B.C. government policy, and that -- the only particular impact there is the increase in water rentals for the third tier.

The fifth was First Nations relationship building, and we've talked about the First Nations initiative, as well as the base budget items, and so both of those impact our costs.

And the sixth was economic and population growth outlook. That probably has more minimal costs in our current application and test period. There are some increased costs in engineering to support BCTC and Distribution investments, which would be tied to broader economic growth. There would be some costs in the LTAP related to growth, projects we've talked about, Fort Nelson and Upper Columbia units. Most of the capital projects that we talked about today really relate to risk reduction and life extension rather than growth. So that's what I wanted to clarify.

MR. CHRISTIAN: Right, and that concludes my re-examination, panel.

THE CHAIRPERSON: Thank you, panel. You are excused.

(WITNESS PANEL ASIDE)

THE CHAIRPERSON: Before we leave for the day, let's just briefly go over our plan, so to make sure we are on the same page. So all the additional written questions to B.C. Hydro are due by end of Thursday, October 23rd. B.C. Hydro replies are due Monday, end of Monday, October 27th. And we will reconvene here Wednesday morning, October 29th, 9:00.

Mr. Fulton, did you have anything more to add?

MR. FULTON: I do not, Madam Chair, thank you.

THE CHAIRPERSON: Thank you. It's been a long day. We are adjourned.

**(PROCEEDINGS ADJOURNED AT 6:13 P.M.)**