YUKON UTILITIES BOARD

IN THE MATTER OF the Public Utilities Act
Revised Statutes of Yukon, 2002, c. 186, as amended

and

General Rate Application for 2008-09 by Yukon Energy Corporation

PROCEEDINGS

May 6, 2009
Held at High Country Inn
Whitehorse, Yukon

Volume 2

TAKEN BEFORE:

Wendy Shanks	Chair
Robert Laking	Vice-Chair
Jody Woodland	Member
Kathleen Avery	Member
Richard Hancock	Member

APPEARANCES

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Robert Laking	Vice-Chair
Jody Woodland	Member
Kathleen Avery	Member
Richard Hancock	Member

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(COMPILATION)

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(PROCEEDINGS RESUMED AT 9:05 A.M.)

THE CHAIR: Please be seated.

Good morning, everyone.

Just with respect to a couple preliminary matters. We would like to have our lunch break from 12 to 1:30 again, and take a short break around 10:30 this morning and an afternoon break around 3 o'clock, and adjourn today around 5.

Mr. Landry, do you have some comments?

MR. LANDRY: Yes, Madam Chair.

We have some undertakings we would like to deal with. We don't have all of them yet, but most of them. And just so that we have them for the record, first of all, I'll go through them and have the panel speak to them.

I'm going from the undertaking summary in the transcript, and the first one is at page 54, line 9, and that was a letter, Madam Chair, that Yukon Energy filed yesterday, so that undertaking has been done.

The next one is a combination of three. It's page 226, line 21;

227, line 2; and 227, line 8, and it related to an undertaking given to Mr. Keough, and I think Mr. Bowman will deal with that.

ED MOLLARD, previously sworn.

PATRICK BOWMAN, previously sworn.

CAM OSLER, previously sworn.

DAVID MORRISON, previously sworn.

A MR. BOWMAN: Yes. Thank you, good morning, Madam Chair, members of the Board.

The undertaking in question related to actual diesel generation in 2008, and the reference in the transcript, as Mr. Landry noted, was page 226 to 227. But at the time we were working with a table with very small numbers out of Exhibit B-10, which was the April 24th filing, and it is in Attachment B of that filing, and Attachment B-2, to be specific, page 14 of 14, in which the actual diesel generation for 2008 by month by plant was provided.

Mr. Keough had asked for information on five of those entries. One related to the diesel generation in Dawson of 120 megawatt hours that occurred in April 2008, and that generation occurred as a result of the

Mayo hydro plant maintenance that took place during the first week of April, and at the time Dawson was, therefore, required to be on diesel, and YEC also used this opportunity to do transmission line maintenance on the transmission line in the area as well. So the generation at Dawson reflects the fact that the hydro plant was being -- was going through maintenance.

The second entry that Mr. Keough asked about was generation occurring at Whitehorse in May for 175 megawatt hours, and that generation occurred as a result of vandalism, a vandalized insulator on Transmission Line L1-70. This is discussed in the application at page 3-5, lines 6 to 8, and it relates to an insulator on the system. And that amount of diesel is being charged for reserve for injuries and damages, as a result of it being vandalism event. So although it shows up in this table, it doesn't actually go into the diesel expense for 2008.

The third entry that Mr. Keough asked about was October of 2008. He actually went through October, November, and

December. So just to fill those in, October 2008, there was generation at each of Whitehorse and Faro for a total of 219 megawatt hours. And that was due to the Whitehorse Hydro Number 3 governor, which was on October 20th the unit tripped off due to governor issues, and it was at a time when Whitehorse Hydro Number 4 was already out of service. So the diesel generation was required over the following couple of days in order to supply the load, and during that period secondary sales were interrupted as a result of the lack of supply of hydro.

Sorry, it was out of service because of repairs. The -- because it was as a result of an outage, it would be discussed in the response to Percival 13(a), which lists the outage reports.

The diesel generation in November, which was a relatively small amount, was 30 megawatt hours, actually relates to two items: the majority of it was a Whitehorse Hydro Unit Number 4 tripping off, and as a result, it was a -- it caused an outage requiring both Whitehorse and Faro diesels to

be run; that was November 12th. And again that one is discussed in response to Percival 13(a), which lists the outage reports. And then a small amount of the fields are in that period, about a third of what's listed for that month, so 10 megawatt hours, was as a result of the connection of the Carmacks-Stewart project. That was where the line was initially being connected for the first time, so there was diesel run for that event. And that was November 5th, and that was just to energize the main line.

December was the majority of the diesel for the year. It was a total of 664 megawatt hours. In the response yesterday I noted that that was due to, in particular, cold weather, which is, you know, more than half of that diesel. And it was a cold period where diesels ran between December 14th and 31st of 2008. There was also an outage on December 1st and 2nd, which required diesel. It's about 300 megawatt hours of the 663. This is related to a failure of equipment at the Aishihik plant, discussed in response to LE-6, a piece of equipment called a pothead failed.

This item was charged to reserve for injuries and damages, or it will be once the project is finally closed out. The repairs for that are still underway. But as a result of it being related to equipment failure, sudden accident equipment failure, as Mr. Mollard noted yesterday. And as I note, the remainder was due to the cold period from December 4th through 31st.

So I believe that covers all the entries that were requested.

MR. LANDRY: And, Madam Chair, the last one for this morning is from page 229, line 14. I think Mr. Osler is going to respond to that undertaking.

A MR. OSLER: Good morning.

The undertaking related to Mr. Marriott. It was a question about correspondence, a reference in the opening statement to other correspondence after the Board Order 2009-1. I can confirm that that other correspondence is exhibit -- is the letter from the Board to Yukon Energy, and it's in the exhibit list as Exhibit A-10.

MR. LANDRY: Thank you.

So, Madam Chair, just for the record, that leaves two undertaking, page 257, line 15, and page 262, line 11. And we're hopeful we'll be able to respond to those by this afternoon.

THE CHAIR: Thank you, Mr. Landry.

Mr. Buonaguro, are you prepared to proceed with your cross-examination?

MR. BUONAGURO: Thank you, Madam Chair.

YEC PANEL CROSS-EXAMINED BY MR. BUONAGURO:

Q Good morning, panel. I'm Michael Buonaguro, counsel for UCG.

Similar to what was indicated yesterday by one of my friends, we also feel that there is quite a bit of material on the record already, so most of my cross-examination is going through and picking up on some clarification points and such, for the most part. And I anticipate -- or I am required by my own plans to be done by lunchtime, because I will be flying out in the afternoon, so I am under my own deadline.

I would actually like to start by picking up on something I noticed

yesterday. A lot of the -- there was some discussion at various points about amounts that are held to the credit of ratepayers which are periodically applied against other amounts in order to achieve rate stability. For example, I think the Faro dewatering account, for example. Do you remember those conversations?

A MR. OSLER: Yes.

Q It occurred to me that I don't have a handle on how many of those accounts exist and what the individual and aggregate amounts being held to the credit of ratepayers for this purpose are, and I was wondering, is that something that is in the evidence already, or if not, is it something you can provide?

A MR. BOWMAN: Mr. Buonaguro, I'm going to be a bit careful as we work through with regard to definitions, just so we make sure that the two accounts that I talk about are clear.

At this point in time, in terms of anything material, the only items that Yukon Energy deals with are the Faro dewatering account, which we talked about at some length

yesterday, amounts held, as I noted, effectively to the credit of ratepayers. It serves as a form of no-cost capital to Yukon Energy such that it -- some portion of the assets are effectively being financed by this cash being held, and as a result, the ratebase is lower. And that's one of the ways that ratepayers get a benefit from. And the other is it can be used one time until the money's gone.

But as I said yesterday, it arises from sales of the corporation to the Faro mine site and the people who were in charge of that site at various points in time from the period '98 to 2004.

That amount, my recollection -- it will be listed at Tab 7. It's dealt with in the opening statement, and by the time -- sorry, page 11 of the opening statement. By the time this -- we come forward in this application, it was -- our recollection is 1.1 million is what was there. There is 467,000 looking to be credit against the reserve for injuries and damages.

A MR. OSLER: 463.

A MR. BOWMAN: 463,000, and a further 87,000 to deal with the 2008 rate stability issue, as you note. So the residual would be whatever the math works out to there, somewhere just north of half a million dollars.

The only other account that would qualify any way in the definitions you use, but it's a very different type of item, is the diesel contingency fund. The diesel contingency fund is an ongoing trust item. I use the word "trust," because that's the way that effectively it's accounted for. It is an account that's been around for a long time. It was first set up under a different name, the low-water reserve fund. It became a diesel contingency fund in '96, '97. It's amounts held to deal with uncertainties related to water flow, in the event there was a very severe drought. The fund effectively pays for the diesel required to deal with that drought.

In the meantime the cash that's in that fund is invested externally. It earns interest. It will be discussed at each of Tab 9 in the audited financial statements, because it gets specific treatment in there,

and at Tab 3 in page 3-21 to 3-22. There has been no charges to that account for some time, but we know from past experience that in the event of a severe drought, even at the load levels today, it could be required to burn diesel for baseload reasons, and as a result, the fund is still needed for the purpose it was originally intended.

And the rules on that, on those monies, are that it has effectively a trigger at $3 million plus or minus, so that it can actually go to amounts owing to ratepayers, owing from ratepayers, and at the time it reaches $3 million, the terms in the negotiated settlement, '96 - '97, state that at that time, some form of rate adjustment will be dealt with to bring the fund back into line.

Q **Thank you.**

And if I remember correctly, that fund has something in the order of 800,000 in it right now, approximately?

A MR. BOWMAN: It's -- I have for the number, page 3-22, was .856 million. But as I note, it's externally invested and earns interest, so the balance this month, whatever

it is.

Q Those are the two counts that meet the definition that I was looking for, right?

A MR. BOWMAN: Yeah, and each of them meet the definition in a sense that they're monies or liabilities of Yukon Energy that are only used pursuant to effectively orders of this Board or rules established by this Board in order to address items you note as rate stability or other things at this Board determines are suitable.

Q Thank you.

I would like to turn to a part of the opening statements where you summarize 2008 actuals. And, specifically, I'm looking at page 10, where you basically summarize that the actual ROE for 2008 -- sorry, this would be Exhibit B-12. The actual ROE for 2008 was 7.2 percent, I guess subject to auditing the statements?

A MR. MOLLARD: Yes.

Q And I would like to turn to an interrogatory response. This is the UCG-YEC-1-19. I think from this point on, I'll just call it UCG-19. It's just easier for me to say. So UCG-19.

And that's . . .

A MR. MORRISON: I'm getting beaten up this morning.

Q And I have only just started.

THE CHAIR: I was wondering when you guys would catch on to the convenience of the computer.

A MR. MORRISON: We're a little dated.

Q MR. BUONAGURO: So I'm looking at Answer B at that interrogatory, where we asked for the actual ROEs for 2005, 2006, and 2007 compared to the last Board approved; you see that?

A MR. MORRISON: Yeah.

Q So am I to understand that this 7.2 percent that's in the update would fit into this 2008 actual ROE? Is it calculated the exact same way?

A MR. OSLER: Yes.

Q Now, you have in that -- in the same update you talk about the Board-approved ROE of 8.64 percent, which is simply, I guess, the recalculation of the ROE with respect to the BCUC rules that you use plus the risk minus the OIE deduction?

A MR. OSLER: That is the ROE that Yukon Energy has supplied to this Board for approval in the 2008 GRA. So it isn't approved yet; it's applied for.

Q Right. But it's based on -- it's calculated in the same way that the last approved 9.05 percent --

A MR. OSLER: Yes.

Q -- in the table was calculated?

A MR. OSLER: The Board approve, in 2005, an ROE based on the same methods derived from the BCUC annual determination of the prospective ROE for the next calendar year, with amounts for risks that the Board determined was appropriate for Yukon Energy and the reduction of a half, 50 basis points, or one half of one percent, that the order in council requires.

Q Thank you.

Now, in the question we asked you to detail any weather normalization that was going on in your response. I can tell you, I added that to the interrogatory because it is my understanding you can do it two ways. You can report your ROE actuals on a

weather-normalized basis or a nonweather-normalized basis; is that your understanding?

A MR. OSLER: I have never undertaken -- I have never heard that we would be reporting anything on a weather-normalized basis.

Q Let me try this. These are not weather normalized, as you indicate the answer, right?

A MR. OSLER: The ROEs?

Q The actual ROEs that are reported in this table, you have done nothing to, from your perspective, weather normalize them?

A MR. OSLER: Correct.

Q So --

A MR. OSLER: I'm not even sure how we would do it, but never mind. But no, the answer is simple. It's not been weather normalized.

Q Now, that means that the actual results that you are reporting here may be over your ROE, your Board-approved ROE from 2005, or they might be closer to it, based on abnormal weather in those years.

So, for example, in 2006,

the 10.59 percent ROE that you are reporting there, that's actual results, and that's based on the actual weather that was experienced in 2006?

A MR. OSLER: Yeah.

Q Which means that if, in theory, I don't know, but it could have been that in 2006 you had abnormally wet and cold weather, which means that you had abnormally high throughput, which means that your revenues would have been abnormally high because -- is that possible?

A MR. OSLER: Yes, it's possible, but -- and we used, I notice in the answer, that we have to take responsibility for having got you on the weather-normalization theme.

Yes, these can vary year by year because of the effect of weather on sales. And if there was a very cold period and there was a lot of extra sales -- we didn't have to incur because we have still got surplus hydro, we didn't have to incur any material increased generation costs, then the returns would tend to be a bit higher.

There could be a lot of other factors. Anything else that pushed sales

up beyond what we had forecast would tend to have that effect, even if it wasn't weather, just bigger growth than people expected, or reductions in costs compared to what we had anticipated, things like that.

So a lot of other things could contribute to this result, and you would have to go through an analysis of each year to understand what caused what and how important was each factor.

Q Okay.

So and if we're going back to 2006, if you wanted to account for how much of that deviation from the Board-approved was as a result of abnormal weather, that process would be weather normalization? It would be accounting for the increase or decrease relative -- or responsible -- sorry, caused by abnormal weather and deducting that or adding that back on to the actuals to weather normalize it?

A MR. OSLER: If one was trying to figure out the impact of weather, you'd have to be able to determine what the sales would have been at something called, you know, "normalized

weather" and how much that affected your generation costs and your revenues. And then you could determine -- you could say that in that particular year, this portion of the difference is due to that factor.

Q And I take it from the way this conversation is going that that's not something that YEC does or normally does --

A MR. OSLER: We don't.

Q -- in reporting its actuals?

A MR. OSLER: No.

Q Thank you.

A MR. OSLER: Part of it, not only do they not normally do it, they don't normally get into, even when looking at sales on a forecasting basis, the normalization process, as you have heard in other answers. So it's not as though they have a weather-normalized number sitting in their closet and they can haul it out for this purpose, because there is a lot of -- there's all the factors that went into why they don't do that even for forecasting that would have to be brought to bear.

Q Thank you.

Now, just to close this off, YEC, as I understand it, takes on what I call the "weather risk" in its forecast.

A MR. OSLER: Generally speaking, yes, and it takes on all other risks relating to forecast.

Q Right.

At the same time, though, you are forecasting, you are not forecasting, as you said, on a weather-normalized basis?

A MR. OSLER: No.

Q Okay. Thank you.

Now, in the Part (c) of this response, we asked about multiyear performance-based regulation. And the answer, in part, and the part that piqued my interest was the last sentence of Part (c) (quoted):

> "Yukon Energy has not assessed measures that the Yukon Government might adopt to bring in legislation or policy related to performance-based regulation."

Do you see that?

A MR. OSLER: Yes.

Q Now, that suggested to me that YEC might have

the position or understanding that unless the Yukon government specifies or requires performance-based regulation or implements some sort of policy related to that that you were prevented from entering into performance-based regulation. Am I incorrect in that?

A MR. MORRISON: Madam Chair, we would, in thinking here, would just be talking about our impression that within the *YUB Act* that this -- this ability didn't exist, but whether it does or not is, you know, is not -- you know, we're not -- we are just giving what we thought. Whether it is, we might be proven to be wrong on that, but . . .

Q Okay.

Now, the beginning of this interrogatory we quoted from the resource plan, the second reference, and it's part of the directions from the Board to YEC. And you'll notice that they talk about full cost of service, rate design, an update to electric service regulations. It also talks about maximum company investment. And these, the ones I have just mentioned, are all things that appear in your letter to YECL, Exhibit B-13?

A MR. OSLER: Is the question are all these types of things cover in the letter?

Q Yeah, I'm asking to confirm that all those things are in the letter.

A MR. OSLER: Let me just check.

Well, certainly the issues of doing a joint full cost of service and addressing rate design matters that flow from that, update to electric service regulations are all covered.

Q Right.

And I think even in paragraph 2 you talk about maximum utility investment?

A MR. OSLER: Yes, maximum company investment, which is part of the *Electric Service Regulations*, would be covered.

The performance-based regulation mechanism in the middle is probably a different thought process that really deals much more with what we're in today.

Q You anticipated what I was going to ask.

A MR. OSLER: Sorry.

Q That seemed to be the one thing that you weren't suggesting to YECL that you considered,

and you said a "different thought process." Maybe you can explain why that particular suggestion from the Board was omitted from this letter.

A MR. OSLER: Well, we didn't have this in front of us when writing the letter. But the letter was based in the context of, Madam Chair, the issues of what people have called Phase I and Phase II, which is a bit different terminology than we were used to.

But going with that terminology, Phase I would be the type of exercise required to review the revenue requirement of each utility.

Q Well, in --

A MR. OSLER: In that sense, performance-based regulation mechanism could mean the ROE type of approach and certain ways of setting revenue requirements such that they could be adjusted based on performance.

They might mean other things as well, but if they meant what I just said, they would be part of the revenue-requirement thought process.

In terms of Phase II,

you'd be saying, Okay, having given discussions of the revenue requirements of each utility, how would that work its way through a joint cost of service, and how would you design rates on a consolidated basis, and what would be the joint electric service regulations for the two utilities, more to do with how do you recover their costs through rates and all of the issues relating to that.

There may be a performance-based element to that that's not in my mind at the moment. If there is, it should be cover in the joint discussions that we are planning with YECL. But the thought was, we are dealing with what everybody asked us to deal with, which was the Phase II type of exercise, the way I have just described it.

Q Although going back to B-13, the letter, on the second page, the last paragraph, you do talk about -- or the company talks about (quoted):

"...in the interest of controlling future regulatory costs in the Yukon, we will need to examine potential future options where YEC and YECL once again can work together, as in the

1996/97 (and earlier GRAs) to address revenue requirement, cost of service, rate design and all other related matters in a single integrated hearing process."

Which suggests to me that you will be talking to YECL, or you are proposing to talk to YECL, about your next rate proceeding and doing a joint basis?

A MR. OSLER: Yes, Madam Chairman, in that sense you are quite correct. All of these topics would be covered in that part of the conversation.

Q When you say all these topics, that would include the possibility of putting forward some sort of incentive-based regulation?

A MR. OSLER: Well, Mr. Morrison?

A MR. MORRISON: No.

A MR. OSLER: If you were talking about jointly filing at the same time, revenue requirement matters, and finding areas where you could facilitate cost-effective regulation and keeping life simple for everyone who has to deal with it, there would be a checklist of topics. One of them would probably be, because

since the Board has asked about it, What is the company's approach in each case to performance-based regulation?

The companies might -- as I said yesterday, the fact that two utilities get together to try and do this doesn't mean they're going to agree on everything.

Q I'll take that point.

A MR. OSLER: So a list is a list, and you see what you can do with it, because the Board has asked you to see what you can do with it. That's as far as I can go.

Q I just want to confirm that it will be part of the conversation. What the results will be, I guess you will find out later?

A MR. OSLER: Mr. Morrison?

A MR. MORRISON: That's correct.

Q Thank you.

I have just a couple of small questions about cost of debt. There was some extensive cross-examination yesterday on cost of debt; I don't want to repeat any of that. I did want to clarify a couple of things, though.

First of all, almost all

the debt, and I think the plan is for all the debt going into the future, is between YEC and YDC, right?

A MR. MORRISON: I can't confirm that, Madam Chair.

Q What part of it can't you confirm?

A MR. MORRISON: Well, all the debt going into the future is going to be between YEC and YDC.

Q Okay.

A MR. MORRISON: We can't -- you know, I'm not prepared to indicate that that's the case. We may have to borrow externally. I have no idea.

Q So in terms of when you do obtain debt from YDC, is there comparisons made on a regular basis to what's available from third parties? Is this part of your analysis?

A MR. MORRISON: Yes, Madam Chair. We have -- in my recollection, somebody -- one of my colleagues on the panel can be more specific, but we have -- my recollection is there is an established mechanism for a debt rate at which we must borrow from YDC so that it is competitive with the market.

And we always look at the market and see where we can get, if it's cheaper or we can be competitive, we'd look at alternatives. But my recollection is that we have to borrow from YDC at a competitive market rate.

Q I think that's my understanding too. There is an actual formula that figures out a base rate, and it adds 120 basis points to it, and that's the rate that you have to borrow from YDC. And I think what you are telling me is that at any point in time, when you are looking to borrow money, you calculate that rate, assuming that YDC has the funds available to lend, which is required, and then you actually do and compare it to the availability of third party debt to see if there is any favourable?

A MR. MORRISON: We do. We constantly check the market. We have, you know, I would say, these days a relatively close relationship with our banker on the YDC side and the YEC side, so . . .

Q So from that can I infer that whenever we see a debt instrument in the evidence between YEC and YDC, is it true, then, that the company, at

that time, reviewed third party -- the availability of third party debt at less -- or at more favourable terms and determined that they weren't available?

A MR. MORRISON: Madam Chair, I can only speak for a period of time where I have knowledge, and so we're talking about some instruments that are older than my tenure. I have no knowledge of that.

But during my tenure here, we have looked at the market. We actually, a few years ago, refinanced all -- a lot of the debt that was on the books, because specifically there was high-interest loans out there, and we were able to get them down to a lower interest rate.

So we have gone through that exercise fairly recently, within the last three or four years, pretty extensively. The cost of the debt was pretty high over the last few years. It started to come down again. I know in the public's -- or there's a perception out there that at zero or half a percent or one percent bank of Canada rates that debt is really cheap. Certainly not our experience in

recent months, talking to our bankers that it's really cheap.

It's anecdotal, and I know we are looking for information in response to an undertaking that will be more specific. But last discussions we had with our banker, they are talking about 6 1/2, 7 1/2 range of debt, and that's not tremendously cheap, from our point of view. Although -- you know, we have a perception, and we think that there's cheaper money out there, but it's not that cheap.

Q Okay. So if I can call it this practice of comparing the available rate from YDC to the market, when appropriate, I expected that that's not something that's been elevated to a written policy.

A MR. MORRISON: No. No, Madam Chair.

Q But it would be something you would consider to be part of your unwritten policy?

A MR. MORRISON: I would consider it -- what we do is we look at things from a fairly practical point of view, and we look at things in the best interest of the ratepayer and where we can get the best option of the ratepayer.

So we do that as part of our normal course of business.

Q Thank you.

Now, in the evidence you were asked to produce the actual policy that sets out how you borrow from YDC, and I don't -- I can't -- I don't have the reference on me, so I'm not going to take you to it, but I did notice one clarification in the interrogatory response which I found interesting, and I just wanted to understand why this once.

In the actual policy, the idea was that the interest rates that you borrow from YDC at would be recalculated at every GRA, do you recall that part of the policy? And then there is a qualification in the interrogatory response that that is not the case because of certain concerns?

A MR. OSLER: Well, I recall the discussion way back that that was what some people thought the policy meant, and I recall getting it clarified that that definitely wasn't what the board of directors meant, and there was a need to clarify to this Board, I

1 think at some point in history that point.
2 '92, my colleague tells me.
3 So I recall that
4 discussion in history, and the board -- I
5 recall being at the Board of directors meeting
6 way back then, and that certainly, in the
7 board's mind, was very clear, they weren't
8 planning to have it redone every time, and
9 eventually that point was made clear to this
10 Board.
11 **Q While you were talking, I found the reference,**
12 **so I thought maybe to be clear, it's CW-26. It**
13 **says, at Answer (a) (quoted):**
14 "The attached financial policy was
15 approved by Yukon Energy's Board at
16 the December 18, 1992 meeting. Note
17 that at the time this policy was
18 written, it was the intent to adjust
19 the long-term interest rates
20 periodically (at each GRA). However,
21 YEC's Board later updated this
22 component at the July 12, 1993 meeting
23 to ensure the rates were locked-in
24 over the long-term, in part to address
25 a concern arising at the 1993/94 GRA."

So I'm just interested in what that concern was and why that -- it seemed like a very specific shift in policy, and I'm just wondering if you could explain what that concern was.

A MR. BOWMAN: Yes, I can go through that a bit.

This policy -- Mr. Osler said he was going to speak to history, but when Yukon Energy was initially set up, the intent was to try to maintain a 60:40 debt-equity ratio, for the reason that that ratio keeps the equity levels lower in the company and, as a result, leads to lower overall rates for ratepayers.

The mechanism to do that wasn't in place at the time. That mechanism wasn't fully worked out until 1992, in the policy that you see before you.

The policy was approved by the Yukon Energy and Yukon Development Board in 1992. As a result of adopting this policy, a particular debt instrument was set up at that time for, my recollection was, $18 million. There was a study done with the RBC

Dominion Securities about the appropriate rate for doing that type of debt. That study was filed with this Board, and it was a matter of significant review during the '93/94 GRA.

In that GRA one of the intervenors, my recollection is the City of Whitehorse, one of the intervenors expressed concern that the debt, as established, may not fairly represent terms consistent with proper long-term debt, because it had this sort of resetting interest rate component of it. And there was -- the IR asked for the policy, and it references the policy and the subsequent adjustment to the policy.

There was also a fair bit of argument at that GRA. There was an argument from the City of Whitehorse and a reply argument in the companies where it was made very clear that the intent is that this debt between the two companies mimic long-term -- any long-term debt available through the market, that it contained provisions that were consistent with long-term debt that would be available from the market, or at least no less favourable, and that it would provide a means

to maintain Yukon Energy's equity levels relatively strictly at 40 percent, so that they didn't drift higher and, as a result, cause our rates to be higher than they would need to be.

So that is the other side of the story, which relates to the regulatory review side of it, that isn't in this IR, because it was asked more about the policy side.

Q Thank you very much.

I'm going to switch now to another interrogatory response. This is UCG-35. And I would like to start with the answer to (a), which is a table that shows labour cost increases and labour charge, capital and deferred projects.

A MR. OSLER: Yes.

Q Now, I just wanted some help in how I am to understand how to read this table. So at -- the first three lines are "O&M labour," "admin labour," and "Labour expense." And with labour expense being the total of O&M and admin, and then it shows the numbers for 2005 to 2009.

And as I follow it down to the bottom of the page, at the bottom of the

table, it has several, I guess, distributor. It says (quoted):

"Yearly increases as %
Economic increase January 1st each year
Number of new positions added
Number of positions cancelled."

So the way I look at this, and perhaps you can confirm whether I'm right or wrong, is that, for example, when I'm looking at the labour expense, or I guess the total for 2006, of $7.848 million; you see that number?

A MR. OSLER: Mm-hmm.

Q I am looking at the increase in 2007 to $8.395 million. The explanation for that increase is partly because of an economic increase in January 1st of 2007 and partly as a result of three positions added? Is that essentially how I'm supposed to read that?

A MR. MOLLARD: That would be the majority of it. There may be other smaller components; for instance, if benefits increased, that would also increase our labour costs. But those two factors would be the

major contributors to the increase.

Q Okay. So again, sticking with 2007, so for the 7 percent total increase as a percentage, approximately 3 percent of that would be due to an automatic adjustment, this economic adjustment, and then the rest was subject to what you're talking about, the other smaller amounts, I guess, that would be factored in, the rest of it would be the three added positions?

A MR. MOLLARD: Yes, that would be correct.

Q Now, this economic increase each year, is that -- I'm going to hazard a guess. Is that something that would be built into the collective agreement and then carried over into the people who are not part of the collective agreement? Is that how that operated?

A MR. MOLLARD: That's correct.

Q And the 3 percent -- I see 2006 is 3 percent; then 3 percent 2007; 3.75 and 3.5. Presumably those are all embedded in the collective agreement?

A MR. MOLLARD: That's correct.

Q I haven't checked this, but is that -- are the

actual numbers embedded in the agreement, or is that a calculation based on certain economic factors each year?

A MR. MOLLARD: The percentages are in the agreement.

Q So 3 percent for 2009, you are "stuck with " as a result of the collective agreement?

A MR. MOLLARD: That agreement has been signed, yes.

Q Sorry. That's -- I said 3 1/2. Sorry, I said the wrong line there. Okay.

Now, there's no -- oh, no. I'm sorry. Skip that.

Now, going to, then, Part (b), you were asked to provide a bunch of tables showing the -- for people who had compensation over $100,000 in each year, so 2005, 2006, 2007, all the positions that had salaries over $100,000. Sorry, compensation amounts over $100,000.

A MR. MORRISON: Total compensation, just to be clear, Madam Chair. Total compensation.

Q Right.

I think maybe part of what you described to me may answer this, but

I'm going to take an example so that you can explain it to me. And I can't help myself. I'm going to take the president and CEO. For 2008 and 2009 and just compare them.

So for 2008 the amount is $204,521.30 total compensation, and the 2009 forecast amount is $223,542.55. Do you see that?

A MR. MOLLARD: Right.

Q So as a strict percentage, that would be approximately 9 1/2 percent, I think you can take subject to check.

A MR. MORRISON: Maybe I'll just answer my own question, okay?

Q Feel free.

A MR. MORRISON: Okay.

Q And so as I understand what we have been talking about, part of that is a 3 1/2 percent automatic increase to salary; is that right?

A MR. MORRISON: Yeah, Madam Chair, I understand what my -- Mr. Buonaguro picked mine, but mine's not a good example. It's done differently. I have a separate contract. I think we explained that in interrogatory, but it doesn't work the same as everybody else's.

Q So do you have a different escalator between 2008 and 2009?

A MR. MORRISON: Well, and I think we explained that mine is done -- with the board -- especially for 2008 and 2009, my contract was looked at as in a hay plan performance-review process and it has very different elements. It certainly -- you know, it's just more difficult to explain. If you wanted to try to do a comparison of apples and apples, it's better to do anyone else.

Q So there's an interrogatory response in there somewhere that explains that?

A MR. MORRISON: That's correct, yes.

Q The one example I picked.

A MR. MORRISON: Yes.

Q So if I go through any one of the other ones, that would be generally the explanation, would be 3 1/2 percent plus or minus, I guess, an additional amount, possibly, due to variation of benefit amounts?

A MR. MOLLARD: As well as overtime for the union contract employees.

Q Okay. Thank you.

Now, in Part (c) of that

same interrogatory, which you have to go back from these tables, I think, we asked for a table that shows the "Average OM&A costs per customer." You are at that table? Okay.

A MR. MORRISON: Sorry, Mr. Buonaguro.

Q It's UCG-35, and it's Part (c).

A MR. MORRISON: Yes, thank you.

Q And there's a caveat where you say "Average OM&A costs per customer are provided as requested," and then I'll just paraphrase. Basically, you are saying but because YECL is one customer, which is much, much, much larger than the rest of the customers, the results don't actually have any meaning, something along those lines, right?

And we asked in this part of the procedure relating to the hearing if you could do the weighting and that didn't happen. Is the weighting process as simple as, for example, if we wanted to fix the column for actual 2005, where we have "Total customers* 1,786," would we basically take customer number, 1,786, which is YECL, figure out how many subcustomers are in that for that customer, and add that amount to the total, and

that would get to the number that we're looking for?

A MR. BOWMAN: Mathematically, if you were just looking to put a number in the numerator that was YEC's costs and a number in the denominator that was all Yukon ratepayers or all Yukon customers, that would get you to a number. I would have some questions or concerns about the meaning behind such a number, given these type of costs-per-customer ratio is typically linked to utilities whose costs are driven by the number of customers they have. At generation level, customers are not the thing that drives costs within Yukon Energy.

So if you wanted to come up with a metric, I presumably that would be the way one could come up with a cost-per-customer number that was driven down to the lower levels. I don't know what meaning one could ascribe to it.

Q Well, you talk about weighting in the response. Do you have a different way of weighting it that YEC felt would be meaningful?

A MR. BOWMAN: Well, there's -- there's

lots of different ways people try to turn their minds to metrics like this. In a cost-of-service study example -- for example, one will sometimes see that when you are allocating customer costs, general service customers get a bigger weighting than a residential customer, and a wholesale customer would be a different story all together.

So there's lots of different ways to do it. It depends on what you're trying to use it for. And as I say, in a utility where the bulk of the costs are generation and transmission, a divisor that's based on number of customers would not usually track or not usually be a metric that reported anything that's of particular note for the generation system. It's not -- you know, adding -- adding a customer at Minto mine versus adding a customer at a house do not drive the same type of costs on a generation-level system.

So I think that's why you don't normally see generation level costs as opposed to, say, distribution costs design to follow a cost-per-customer type of metric.

Q Is there a way that you can take out YECL, like, and have it -- and have -- I mean, you seem to be telling me that you can't -- you can't provide any meaningful metric that shows what you were spending on OM&A per customer. I find that hard to believe.

A MR. BOWMAN: I think the problem we're running into, Mr. Buonaguro, relates -- just relates to a general understanding of the -- of the way that the system works in Yukon, where Yukon Energy is basically a generation and transmission utility. It serves some customers, but they're by far the minority in Yukon, 10 percent.

So the costs from adding customers tend to be distribution-related costs, and they tend to link reasonably well for distribution-level changes in revenue requirement, and that's why distribution companies will often try to go to a metric of cost per customer.

Generation-level companies don't usually use that type of metric. They usually use different types of performance metrics, similar to some that

Yukon Energy tracks. And they of course have their own sort of story embedded in them, cost per kilowatt hour generated, let's say. That has its own issues related to when you have a system of surplus hydro.

But, nonetheless, those type of metrics track generation-level costs, at least, or costs per kilometre on a transmission-level system.

Cost per customer are typically more a distribution-level type of metric, so you're effectively taking one type of number, a generation and transmission cost in the numerator and another type of number, the number of customers, the denominator, and they don't mesh really well. That's all I'm getting at.

Q **All right. So you mentioned as part of your answer the metrics that YEC actually tracks, presumably because you find that those metrics are meaningful?**

A MR. BOWMAN: Well, Yukon Energy does have certain key performance indicators that are filed with this Board, and I believe Yukon Electrical has its own, and they come out

of much earlier discussions before this Board. They come out of a time when the two utilities were managed jointly. So whether they are perfectly aligned to a generation company as opposed to largely distribution company, I can't say. It's not something a have spent a lot of time on recently.

But costs per customer of this type is -- you know, wouldn't be one that probably carries a lot of meaning is --

Q So, again, when you talk about the metrics that Yukon Energy Corporation tracks, and you said you file with the Board, is everything you track already in the evidence?

A MR. BOWMAN: There is an annual KPI report filed with the Board. It's pursuant to the template that was set out by the Board, but it's a public document.

Q Is it filed in this proceeding?

A MR. BOWMAN: I don't recall that it's filed in this proceeding, no.

Q Perhaps you could file it in this proceeding, the most recent.

A MR. MOLLARD: Sure.

A MR. BOWMAN: That's fine, yeah.

1 **Q Thank you.**
2 A MR. BOWMAN: It's a public document,
3 yes.
4 THE CHAIR: Just to be clear,
5 Mr. Buonaguro, you are asking for what year,
6 the most recent KPIs?
7 **Q MR. BUONAGURO: I would expect we would**
8 **want the most recent one, and then I am**
9 **assuming, and maybe I'm wrong in assuming, but**
10 **that that would show relative to previous**
11 **years' filings how performance has changed, or**
12 **am I completely wrong?**
13 A MR. MORRISON: Madam Chair, if it's
14 helpful, could we give you a year or two back?
15 **Q That would be good. Since we are basically**
16 **dealing with a gap between 2005 and 2009, we**
17 **would get whatever you have for those years,**
18 **that would be fine. Thank you.**
19 A MR. MORRISON: That's fine.
20 **Q Thank you for the clarification.**
21 **I would like to turn to**
22 **UCG Number 38. And, in particular, I'm looking**
23 **at Attachment 1, which is response to Part (b)**
24 **of the interrogatory.**
25 **And on this particular**

table, which is "TOTAL HONORARIA PAID TO YEC BOARD MEMBERS FOR 2005-2008." We noticed a significant jump with respect to the chairman between 2007 to 2008, from $38,200 to $57,197.

So I was just wondering if you could explain why that particular position increased by, I think it is, something in the order of 30 or 40 percent in the one year.

A MR. MORRISON: Madam Chair, just can you just give me a minute? I just want to check something.

Madam Chair, if I'm -- I'll check something at the break, just -- but let me try to answer now, and I'll check it, and if I have something to add to it, hopefully I can add to it again for Mr. Buonaguro.

Generally, the chairman's fees are simply based on the amount of work that he does. So he's involved in a number of different things that he does. As you can see, obviously a lot more work than chairing meetings.

And a big part of what he does is dealing with -- it's the chairman's job

to deal with the Minister, senior government officials on issues relating to the corporation. He, in our case, has some specific expertise that we utilize, and so he's very helpful on a number of matters, including some of our water-related issues and First Nation relations and public meetings that we use him to go to. So there's a big jump.

What I'm getting at is the board -- board fees changed in -- and I can't remember whether it was 2006 to 2007 or 2007 to 2008, so part of it may be because some of the board fees increased, and I'll check that and just confirm, if that's all right.

Q When you refer to "board fees," like fees for particular --

A MR. MORRISON: For meeting fees.

Q I see.

A MR. MORRISON: Their remuneration for per diem for --

Q I see. Like a tariff of some sort.

A MR. MORRISON: Yes.

Q I could appreciate the clarification, if we could get that as an undertaking.

A MR. MORRISON: I'll do my best.

1 **Q And then -- okay.**
2 **So, basically, looking at**
3 **that table, between 2005 to 2008, it just so**
4 **happens that between 2005 and 2007, subject to**
5 **changing the tariff, the activity was**
6 **relatively stable, and then in 2008 the**
7 **activity went -- presumably there was increased**
8 **activity and that the chairman was then**
9 **charging or, I guess, docketing more time on**
10 **more different things and, therefore, incurring**
11 **more fees; is that generally the explanation?**
12 A MR. MORRISON: Yeah, that's generally
13 the -- I mean, the amount of work that he does,
14 it seems like it's been pretty steady, although
15 the difference between 2006 and 2007 is, you
16 know, $8,000. So it depends on what -- you
17 know, what kind of level of activity we have
18 going.
19 And in 2008 we were
20 building the line, and there was a lot of other
21 activity underway, and the chair is pretty
22 actively involved.
23 **Q Now, the -- my understanding is that there is**
24 **an order in council that sets the YDC chair's**
25 **remuneration at 38,000? Not YEC but YDC?**

A MR. MORRISON: That's correct.

Q Can you explain the difference between what the YEC chair does and what the YDC chair does.

A MR. MORRISON: The YDC and YEC chair do very similar things for their respective corporations: chairs meetings; undertakes, you know, briefings for ministers. Just given corporation, does the same things.

Q Thank you.

I'm going to turn briefly to UCG Number 94.

A MR. MORRISON: Sorry, 94?

Q Ninety-four.

This undertaking refers to the costs of the out-of-court settlement with respect to Mayo-Dawson transmission. And, in particular, we just wanted to confirm that the numbers at Part (b), do you see those, "Internal Labour 17,758," for example?

A MR. MORRISON: Yes.

Q So that, internal labour costs, would have been deducted from the labour costs that we referred to earlier in, I think, the table at 1-35, UCG-1-35. Has it been accounted for in that way?

I ask because internal costs would be something that somebody's already getting a salary for, and then I'm assuming that you've -- you've allocated an amount of their time to this particular task and then deducting that from your basic revenue requirement. That's what I am assuming is happened. I am trying to confirm that that's in fact what happened.

A MR. MORRISON: If you could just give us a second.

A MR. MOLLARD: Can you repeat the question so we answer the right thing.

Q Sure.

So looking at Part (b), you have identified all the different cost categories for the claims process. And then in Part (c) you have said that these costs are not allowed in regulated operations and so are excluded from this application.

So the first area of clarification was to confirm that the internal labour, which I have assumed is money that's being paid to internal staff already and, therefore, needs to be deducted from revenue

requirement in order to actually exclude it from the application, to confirm that that was done; that's the first part.

A MR. MOLLARD: There are no amounts in 2008 or 2009 revenue requirement that relate to this settlement.

Q What I'm trying to confirm, that that means that there was an exercise where somebody's salary -- like, presumably internal labour of $17,758 means that somebody in terms of the company whose salary is part of your overall revenue requirement, part of that time was allocated out of the revenue requirement. And I just want to make sure that that happened.

A MR. MOLLARD: Just to be clear, Mr. Buonaguro, the internal labour charges that are recorded in UCG-94 (b) were all incurred prior to 2008.

Q I see. So that means that the only, I guess, usefulness of those numbers in terms of evaluating 2008-2009 is with respect to -- I guess there would be 2007 that that number would have been included?

A MR. MOLLARD: Claims go back to, I believe, 2005, so . . .

Q Okay. So to the extent that they would have been removed from revenue requirement, they would have been removed in 2005, 2006, 2007, somewhere in there?

A MR. MOLLARD: They would have been taken out in -- in previous years of '5, '6, and '7.

Q Thank you.

For the rest of the expenses, I think you are saying that they were just never add -- are you saying they are also out of period, they are not 2009 costs?

A MR. MOLLARD: As the settlement occurred in 2008, there would have been some 2008 expenses. Those expenses were never included in the revenue requirement before us.

Q Thank you.

At UCG Number 46 we asked about payment in lieu of taxes. And I just have a very simple question: We were trying to figure out where exactly how it is that you are required to do that and the process that's required. We looked, for example, in the *Assessment and Taxation Act* and couldn't understand if that was what was directing you

to do payment in lieu of taxes.

Can you give me a summary of how your payment in lieu of taxes is done and under what act?

A MR. MOLLARD: If you give me a second, I just want to review the IR.

Q Sure. It's UCG Number 46.

At Part (e) we've said (quoted):

"Please provide documentation outlining YEC's requirement to make payments in lieu of property taxes to municipalities."

And the answer at Part (e) was (quoted):

"Yukon Energy is owned by the YTG and therefore it makes payment in lieu of property taxes to municipalities instead of actually paying property taxes."

And we just wanted a little more understanding of where that requirement comes from, that's all.

A MR. MOLLARD: So the payment-in-lieu-of-taxes requirement,

Madam Chair, comes from the Yukon *Assessment and Taxation Act*.

Q That's what we thought, but I guess -- and maybe it's just a -- is there a particular section I should be looking at?

A MR. MOLLARD: I believe I have a reference, if you just give me a moment.

Q Sure.

It's not something I need right this second. If you want to do it at the break or by way of undertaking, that's fine. I don't want to dwell on --

A MR. MOLLARD: Sorry, I have found it.

Q Okay, great.

A MR. MOLLARD: It is sections 63 (1), 64 (2), and 66.

Q Thank you.

Now, we asked you some questions, or at least one question, about the wind turbines used for generation. Particular UCG Number 30, we asked for the production numbers. And I don't have actual questions specific to production, but I just wanted to reference that as where we asked about wind turbines.

Can you tell me, with respect to ratebase, what, if anything, is in ratebase for the test years with respect to wind turbines?

A MR. MORRISON: operating costs or capital and operating?

Q Well, I'm going to ask about both. So at ratebase there would be or should be something, or not, depending on whether it's been depreciated, depending on how it was paid for. I'm just trying to confirm what part of ratebase, first of all, is related to wind turbines?

A MR. MORRISON: I have -- Madam Chair, I would have to get the number. It's not a number I have at the top of my head.

Q Okay.

A MR. MORRISON: Just in -- for the record, though, one of the wind turbines was paid for by capital contribution. So I think we've had this discussion previously, and we'll dig out the numbers.

Q I think you anticipate the second part of the question, the O&M costs, I guess, per turbine.

A MR. MORRISON: We'll -- I think we'll

have to do the same, Madam Chair.

Q Okay. Thank you.

And then as part of that undertaking too, if you could, for the O&M costs, if you could relate that to the kilowatt hours produced or anticipated reduced, I guess, over the test period 2008-2009, so we get a sense of how much you are spending OM&A per kilowatt hours for that particular area of generation. Thank you.

A MR. MORRISON: Yes.

Q Now, I would like to talk a little bit about customer complaints. Not that I have a particular complaint, but rather the process that's involved with respect to making customer complaints.

My understanding is that the *Electric Service Regulations*, for example, don't address a complaints process, but rather the complaints process is through the *Public Utilities Act* -- part for the *Public Utilities Act*; is that correct?

A MR. MORRISON: I'm not sure.

Q You're not sure?

A MR. MORRISON: I don't know the answer

to that. I can certainly find out for you, if you would like.

Q I think that's true, but let me put it this way, then: From YEC's perspective, what do you do to facilitate the reporting and resolution of customer complaints with respect to this service that YEC provides to its customers?

A MR. MORRISON: Well, we -- A) we take customer complaints and look at them and make every attempt to resolve them. I can't recall any that have been, at least in the recent while that I have been around, that we have any that have been resolved to a higher authority to be -- to be dealt with.

Q Now, in terms of --

A MR. MORRISON: And, sorry, and Mr. Mollard would like to jump in.

A MR. MOLLARD: Just if I can add to that. We do -- customer services is in my area, so my front-line staff usually get the first-line complaints, and we have an escalation within the company that we go through if customers are dissatisfied with the response they get from front-line staff. They will elevate to a supervisor, to a manager, to

myself. And if at that level they're still not satisfied, I generally will refer them to the Utilities Board to forward their complaints.

Q Now, in terms of this process, in particular with respect to escalation and the ultimate potential reference of the Utility Board, is that something that's -- well, first of all, is that something that's documented? Is there a policy with respect to that?

A MR. MOLLARD: There is not.

Q So as a customer entering into that process, if I have a complaint, then I call up YEC, there is nothing in writing that I may have been able to see in advance to understand what the process I'm about to enter into is going to be like?

A MR. MOLLARD: Outside of the *Utilities Act* Rules, there's not.

Q And in terms of customer communication, do you put anything out there to your customers to explain that they have this process available to them?

A MR. MOLLARD: We're pretty clear that -- I mean, we try as much as possible to indicate to customers the contact available to

them, to the company, so that there's multiple ways via email, our web blog, and via our customer service hotline; they can get in touch with us if they have an issue.

Q **Okay. But beyond the notice as to, You can get a hold of us here if you have a problem, I guess which I presumably --**

A MR. MOLLARD: Yeah.

Q **Is that through advertising or through billing services or --**

A MR. MOLLARD: It would be on our bills; it would be on all our communication.

Q **Beyond that, the process is something which is -- I'm going to call it "informal," only because you don't have a written policy; is that fair?**

A MR. MOLLARD: I would agree it's not written.

Q **Would you agree that it's informal?**

A MR. MOLLARD: It's well understood by the people that are -- that are involved in it, if I could say that.

Q **When you say "involved in it," you mean from the perspective of the company?**

A MR. MOLLARD: Correct.

Q As opposed to the people who are complaining?

A MR. MOLLARD: I can't presuppose what they would understand.

Q Okay. Thank you.

I would like to ask you some questions about Rider J. We asked about it at UCG Number 14, for example. Now, this is the -- this is the rider that, I guess the way I have understood it, replaces lost revenue from the Faro mine; is that a simple way of putting it?

A MR. OSLER: That would be a simple way of putting it.

Q And throughout the interrogatory responses, I note that you have been very specific that it covers both recurring costs, so costs that have been recurring since the mine left or closed down, but also one-time costs, from --

A MR. OSLER: What you said the first time was that it deals with the lost revenue from the shutdown of the Faro mine. And today that's essentially what Rider J, in simple terms, is doing.

Initially, when it was first instituted, it had some other functions

as well, to do with what you're calling "one-time costs." But Yukon Energy came to the Board when those one-time costs had been amortized and completed and requested that the rider be reduced to reflect the fact that those were no longer appropriate. So I forget the -- about 2003.

Well -- and Mr. Bowman reminds me, the Board, on an interim basis, has recently reduced it to do with the revenue reductions that the company has brought forward in this application. So we're moving further and further away from the relevance to the Faro mine.

At the moment I think the history is less relevant than the reality that this is a method for collecting revenue, until such time as somebody goes through the process of adjusting rates to not need the rider. The rates have to go up; the rider could go away.

You have just seen the same thing happen, Madam Chair, with the Rider F. I mean, since the two utilities were before the Utility Board in '97 and had GRA rates fuel price forecast then, we have not had

the opportunity for both utilities to be brought whole in terms of fuel costs into their revenue requirements until YECL was before the Board last year.

Now that YECL's revenue requirement has been determined, it includes fuel price that are up to date, so to speak. And as you have seen, the Rider F has now gone to zero.

And, you know, there's a proposal in compliance with Order 2009-2, a proposal as of January 1, 2010, to increase -- put in a new rider of 10 percent in order to recover all those fuel costs plus a little bit more that the Board has allowed.

So, essentially, Rider J is the same type of thing. It was an interim measure that the company proposed to the Board, the Board approved in 2008 as a quick way to deal with the closure of the Faro mine, in a simple, expedited manner. But we never contemplated at the time that we did that that this would be around this long, okay?

There was a general expectation in the atmosphere in 1998 that we

were just about to have another GRA. So that's -- forecasting is not always an exact science.

Q Thank you. I found that quite useful.

So, I mean, it sounds like I hit the nail on the head with my simple summary of it, which is that really it's -- it represents a portion of your normal revenue requirement, not related at all to costs anymore with the Faro closing, but rather costs that would normally be allocated across all classes based on the cost allocation, but since you don't have an up-to-date cost allocation.

And I also because presumably you are restricted through OIC from increasing costs, for example, to industrial customers, that you use a rider to allocate this missing revenue to remaining classes.

A MR. OSLER: Okay. I'll try and keep it simple.

The revenue-requirement issue and the rate issue, in the sense that we're talking about, are quite separate boxes.

Q Okay.

A MR. OSLER: One tells us how much we are allowed to collect and need to collect from customers in order to make the company whole, or YEC whole, and the other one is the authorized method of doing it through rates.

To keep it simple, 1997, the Board had approved, assuming the Faro mine was there, a revenue requirement and a bunch of rates without any of these riders. Faro mine closed. The company lost a lot of revenue. It had some costs reduced as well. The net difference was in the order of magnitude, and I'm speaking entirely from fading memory, 5, 6, $7 million out of 13 or 12 or something total revenue. So there was a net amount we still had to pick up from other customers because of the fixed cost to the system.

We were all alone, YEC, before the Board. YECL wasn't there anymore. The Board had let them off. And, essentially, Madam Chair, we had to pick up that amount of money. And the simplest way to do it was simply to have a Rider J that applied to all retail customers in the Yukon, there was the amount of percentage that would recover that

shortfall, was about 15 percent, let's say. That's all that's happened today. It's just a method of collecting money from all the retail customers in Yukon by a percentage.

And it's adjusted in -- it can be adjusted from time to time over this history as the Board authorizes adjustments in how much should be collected. It just sort of moves up and down.

This new rider that YECL is bringing in is a similar one. Rider R that's there right now and the new ones they are talking about are just simple methods of across the board, all customers, both companies, all rate blocks, all charges, customer charges, demand charges, first-rate block, second-rate block, everything gets applied this universal number. It's a very crude method of collecting money compared to redesigning rates.

But the redesigning rates, as we have just been talking about, is a different process from collecting -- from determining how much you should collect.

Q And I think, just for the reference, I think in

UCG-5 (c) you explained, I guess, the complexities of trying to incorporate Rider J into base rates?

A MR. OSLER: Oh, yes. I can remember that.

Q I am going to leave that now.

Now, and also through interrogatories, you have confirmed that -- and I'm just going to reiterate from my understanding, secondary energy users are charged Rider J, correct?

A MR. OSLER: Right. And the reason for that is that they have a very specific rate. It's based on value. Certain percentage of their alternative fuel cost. I has got nothing to do with cost of service; got nothing to do with revenue requirement or our cost. It is just a method of taking some surplus energy and collecting some money to keep rates down for everybody else.

Q And industrial customers are exempt specifically because of the OIC?

A MR. OSLER: Yes, the OIC 2007-94 relating to the rates to be charged to them.

Q Okay, thank you.

A MR. OSLER: Well, Mr. Buonaguro, just there was a fuel element in the rate that is charged to the industrial customers up to November 2006, and there is an adjustment mechanism for adjusting what they are charged based on fuel price changes. So the concept was that that particular element does fluctuate in their charges, but all the rest of it was locked down by the order in council.

Q Okay. Thank you for that clarification. My clock says 1:30 p.m. I think that's central.

THE CHAIR: We are coming up to the time that I think we would take a 15-minute break, if that is an appropriate time in your questioning.

MR. BUONAGURO: That would be great, thank you.

THE CHAIR: In that case we will take a 15-minute break.

(BRIEF ADJOURNMENT)

THE CHAIR: Please be seated. Would you like to proceed, Mr. Buonaguro?

MR. BUONAGURO: Thank you.

Q MR. BUONAGURO: I have a couple of questions on Rider F, and I guess the best place to be looking at while we are at the questions is in the application at page 321, I believe, at Section 3.6 has a description of the rider.

My understanding, simply put, is that in your rates, you have a forecast fuel price and a forecast fuel consumption, and that this rider tracks deviations from that; is that correct?

A MR. MOLLARD: Just price; not consumption.

Q Okay. So does that mean that when you calculate the rider to be applied in order to capture the variation in price, you are only capturing the variation in price as it relates to the amount of fuel you forecast over the test period, to consume?

A MR. BOWMAN: Perhaps, Mr. Buonaguro, just to help people out and make sure we're all on the same page, Rider F is an account that Mr. Osler referred to earlier is the account that effectively is a pretty typical type of fuel stabilization mechanism. Most utilities

that use a lot of fuel would have something of this sort.

The account effectively simply calculates off of the price. So when Yukon Energy had its last rate application, 2005, there was a set of fuel prices approved for 2005 for each community, and they're unique by community. My recollection is 56 cents for Whitehorse. I can look up the exact number if you want. There is a price for Faro and for Mayo and for Dawson.

From that time forward, 2005 forward, whenever Yukon Energy consumes fuel for operating purposes, fuel that goes through operating maintenance, the fuel is booked at that standard price.

Any variation in that price -- in the price, up or down, in terms of what Yukon Energy's purchasing fuel for or consuming fuel flows through the account. So if a litre of fuel is used out of the tank that was bought with an average price of 66 cents and the amount in rates would be 56 cents, Yukon Energy would book 56 and it would charge 10 cents to the Rider F account, what's

actually called the "deferred fuel price account."

Once that account, which has the 10 cents charged to it, and then all of the other adjustments both ways, reaches a certain trigger or balance or forecast between Yukon Energy and Yukon Electrical who each have these accounts and they manage them effectively in a coordinated way, a rider or a refund will be put in place with customers to deal with the balance in the account.

So the rider side is different than how the charges arise -- give rise to the balances. But I hope that's helpful to people in the room.

Q Well, I think so.

The problem I'm having in, I guess, understanding it, and maybe it's a small point, but I understand it tracks the variation in price, but price by itself is meaningless unless you have a volume and the year that you are applying it to, so a volume of diesel fuel consumed.

And maybe I'm misunderstanding, but I assume that if you are

fixing a price in your rates; for example, you are proposing a new price for this rate proceeding to be embedded in rates, correct?

A MR. BOWMAN: Correct.

A MR. OSLER: Yes.

Q But that price is to go along, I would assume, and maybe I'm horribly wrong, with a certain volume to create an amount that's simply recovering rates.

A MR. BOWMAN: Yes. When you're developing a revenue requirement, you need a total number of dollars. So in this application there is a price for -- forecast price for Whitehorse for 2009 that would be $1 and 14.9 cents per litre for a given number of litres forecast.

When actuals arise, the way forecasts work, the price won't be right and the volume won't be right. They never are. That's the way forecasts work. So if the price, instead of a $1.15 went to .85 cents, so you have a 30-cent gap, and if the litres, instead of whatever number is in here, 300,000, became 500,000, Yukon Energy would be crediting back the account 30 cents for all 500,000 litre

consumed, every litre consumed, for operating reasons.

Q Thank you. So that really helps, because the stress has always been on the price, it seemed, in the way it's described. But, in fact, you are actually -- that account also accounts for variations in volume.

A MR. BOWMAN: Well, no. I don't agree.

Q Okay.

A MR. BOWMAN: I want to --

Q I misunderstood what you just told me.

A MR. BOWMAN: Well -- the account doesn't deal with variations in volume to the extent that those variations in volume reflect a change in cost to Yukon Energy at the GRA-approved price. It deals with all units consumed, so it deals with variations in volume at the variation in price. And these conversations can get hard to follow if we're not careful.

But the -- at the end of the day, Yukon Energy, as we have covered before, is at risk for its load forecast and how it supplies its load forecast. That's a pretty typical standard in dealing with

utilities. So if there is an outage and you have to burn fuel, Yukon Energy pays for burning that fuel. If loads come -- it gets cold, so there's peaking diesel, Yukon Energy pays for that diesel. If loads are higher than forecast or lower than forecast, Yukon Energy absorbs the change in revenue and the change in cost to supply that.

At the same time, one thing that Yukon Energy does not take the risk for, similar to almost any utility that is in a similar position, is for changes in price that it can control. So this account is designed solely to deal with the risks related to changes in price. And in that regard, every litre of fuel that Yukon Energy books is at the GRA-approved price. It's at risk for changes in consumption, changes in volume at the GRA-approved price.

If there's costs related to changes in the price, it goes through the Rider F account. That's not something that the utilities are at risk for.

Q Okay. So that's -- I understood that differently than what you had said just prior

to that, so I am going to try an example again to see.

So in 2009, for example, what's the forecast fuel price that you're using for the 2009 test year?

A MR. BOWMAN: For Whitehorse is $1 and 14.9 cents.

Q **And what's the forecast volume of diesel consumption?**

A MR. BOWMAN: Well, the forecast volume for the entire company is 451,300 litres. And that would be in CW-17.

Q **Okay. It's just an example, so if -- it doesn't need to be precise.**

A MR. MOLLARD: Yeah.

Q **So you have a forecast price, you have a forecast volume. If the price doubles, the account will capture that?**

A MR. BOWMAN: If the price doubles, the account will capture that for every litre consumed, correct.

Q **If the volume is cut in half but the price remains the same, the contract's nothing?**

A MR. BOWMAN: The contract's nothing. That is a volume-related variance, so that's a

load-forecast related variance, which Yukon Energy is at risk for. Whether that volume of litres goes in half or doubles.

Q Okay. That's the clarification I was looking for. Okay.

So if we can move on. I have, I guess, something -- it's a related question about the DCF, which we spoke of briefly earlier, the diesel contingency fund, which is on described on the same, page 3-21. And you mentioned -- actually, in your earlier description, you mentioned triggers, and that's precisely what I wanted to confirm, because I don't think -- it's not in here.

My understanding is that that fund is supposed to protect against variations in water flow, simply put, in the first instance.

A MR. BOWMAN: Correct. Correct. It's -- yes. It's called the diesel contingency fund because it protects against changes in the amounts the utility has to pay for diesel as a result of water-flow variations. The name sometimes causes confusions; it's a water-related fund not a

fuel-related fund.

Q So if water flow remains as forecast but load doubles, for example, this fund isn't triggered?

A MR. BOWMAN: If water flow results in hydrogeneration being equal to the long-term average, which is the numbers that the DCF works off of.

So if you still get as much water as a long-term average would say you should get but the load doubles, this fund is not triggered.

Q Right.

And, similarly, if your production is cut in half because of a technical failure in a turbine, that has nothing to do with this fund?

A MR. OSLER: We'll have to be careful. It deals with generation, hydrogeneration being able to produce based on assumed long-term water. And certainly if there was a transmission failure that led to a problem that would not trigger the fund, I think we'd need to check that in history there weren't -- how do we deal with some problems with generator

units not being able to perform. You know, there may have been some history there.

But this fund is only relevant when there is diesel in the margin, the way I was talking to Mr. Keough yesterday. So back in the '90's when diesel was being used in the Whitehorse-Aishihik-Faro system. So you were running diesel, and the water flow -- you know, secondly, it's not based on a forecast. We changed all that in the early '90s. It is just based on the long-term average, so that we are not getting into the game of trying to forecast water for each GRA or something.

This is the long-term average. If we're above it or below it, and you had diesel in the margin, you would have to run more diesel or less diesel, if the water flows better than long-term average, or more diesel if the water flow was less. And this fund picked up the difference so that people weren't having GRA revenue requirements bouncing up and down depending on water flows. That's the essence of the point.

In the history of dealing with it, I just don't remember -- I don't know

how we'd find out real fast, but whether or not there were some examples when we had a problem with the, say, Whitehorse Number 4 or something operating because of a technical malfunction, whether that was used to be recover from the fund or whether it wasn't. That's the only query that I have.

Q So from what you are telling me, you are saying A) historically, it may have been used in that situation. But as I understand, I think it's right in the description, this is a fund that was created subject to -- or pursuant to a negotiated settlement?

A MR. OSLER: Yes.

Q And presumably the settlement contains the terms under which the fund was supposed to be used?

A MR. OSLER: It's a short document and, you know, things evolve, so I don't think this -- it's filed with the Board and was approved by the Board in the '96/97 GRA, so it's a matter of record what the settlement is. And it's not that long a document that covered a lot of different topics. This is just one.

Q Is it filed in this proceeding?

A MR. OSLER: No. It's filed in -- no. I would expect it's attached to an order that approved it.

A MR. BOWMAN: I will just add on, the negotiated settlement from the '96/97 GRA is what Mr. Osler was referring to that dealt with establishing the DCF out of the earlier low-water reserve fund.

In implementing that order, Yukon Energy ran the fund for three years, '96, '97, '98, and came back to the Board and got an order confirming how it had used the fund. And it's an order from 1999 dating, if I recall correctly, and there's a filing related to that that basically describes the fund and how it was implemented, and that was confirmed by the Board.

So, if anything, the operating rules took a bit of time to get confirm in the right way. But it is a way they are now applied.

But every year the additions and deletions to the fund, which have basically been only interest for the last few years, are filed with the Board.

A MR. OSLER: We -- okay.

Q Okay. So maybe if I could ask for a copy of the original settlement and then the second order you are talking about, which confirmed how it was used, between the time of the settlement and that order. I wasn't following all the dates, but I think you know what happen I'm talking about.

A MR. OSLER: We can give you the Board order and the -- and the settlement that the Board approved back in '96 and the one that Mr. Bowman was referring to later on where the Board -- we'll give you that order that --

Q Thank you.

A MR. OSLER: And whatever is related to it that's useful.

Q Okay. Thank you.

Now, you did mention, you said this account is only -- maybe I'm mischaracterizing what you said, but I thought you said that this is only an issue when diesel's on the margin. But I think you agree that when -- the second point at page 3-22 with respect to the fund says (quoted as read):

"When diesel is not in the margin, the

account can, in certain circumstances, be used to pay for the cost of generation using diesel, i.e., in the case of drought."

A MR. OSLER: Well, we're using the language "on the margin" is being used here as base-load diesel running all year round, and it's just allowing for the possibility that because of low water flows, there may be certain months that diesel had to run. And if that could be established, that it was due to the low water and not due to something else, there would be a basis for charging the fund.

Even when the Faro mine closed, after it closed, the fund was charged, if I'm not mistaken, in the subsequent spring, because water flows were very low. So it was -- it was even without a high load, if the water gets low enough, there could be certain months when the water flow, being low, is what's causing the diesels to run.

Q Okay. Thank you.

I'm going to look at UCG-1, UCG-1 (d), which I think is a quick question. You are asking -- we asked (quoted):

"Please provide details of service reliability criteria that YEC uses as a policy guideline."

And the answer, I think, quite simply was (quoted):

"YEC does not use service reliability criteria as a policy guideline."

Could you describe that more fully. Because I would have expected that you would have some sort of reliability targets or some such that you strive towards, something like that, at a matter of policy, and this suggest that you don't.

A MR. BOWMAN: I think, Mr. Buonaguro, we might need you to repeat the question. I think the 1 (d), which is about the criteria is referenced as a policy guideline, and I think the essence of the response is focusing on there is no policy along these lines.

But I think your question may not have been about that, so perhaps we could --

Q Sorry.

A MR. BOWMAN: -- benefit from a repeat of the question.

Q So what you just said suggests to me that you do have service reliability criteria that you use.

A MR. BOWMAN: Well, all I said is --

Q Whether it's uses as a policy guideline or not, we can forget that part of the question first. Does YEC have any kind of service reliability criteria that it uses in any capacity?

A MR. MORRISON: We are having a little internal debate. We are not exactly sure what you are referring to when you mean reliability standard. So I guess that would help if you could help us with that a little bit.

Q Well, how do you measure your actual reliability in a particular year and how do you determine what reliability standard you want to achieve, and then therefore how does that drive your investment, presumably, or your spending on reliability?

A MR. MOLLARD: So it actually is part of the KPI documents that we're going to provide to you. There will be reliability data in there, the standard Canadian SAIDI, SAIFI, and CAIDI, don't test me what those acronyms are.

Q I have heard of them. I'm not sure what the

acronyms mean either sometimes.

All right. Thank you. That will be very helpful.

I haven't seen those documents yet, but presumably the reports don't just set out the criteria but talk about how you use them and what you intend to use them for, is it?

A MR. MORRISON: Well with, again, Madam Chair, I'm not exactly sure of the question. But what the reports outline is what our reliability experience is and compares it to other parts of the country, and there are discussions around that, and it also explains what the standards mean and how they're measured.

Q Okay. I guess I'll see when I read it. Thank you.

Now, I would like to ask you some questions about the proposed runoff rates for residential customers, which you went through, I think, a bit yesterday already, so I'd only have some what I call "follow-up" questions. And I think a useful place to be looking at would be the application, 4-10, page

4-10 and 4-11, I think.

And this is where you start to describe the runoff rates and the requirement under the OIC and so on.

And over at page 4-11, at the top, you talk about trying to provide -- and I'm paraphrasing, trying to provide a strong economic disincentive to customers from using electricity for space heating at that time. And the impression I get from the evidence is that the primary goal in -- or the primary behaviour that hopefully the runoff rate is supposed to incent is to refrain from space heating for using electricity.

A MR. OSLER: I think the impression that the filing gave was that -- I don't dispute that, but in retrospect, it's not a good impression in the sense of the full purpose of the runoff rate.

First of all, the runoff rate applies to customers in general service as well as residential, and the concept, as buried in Rate 39, even for industrial.

So the whole idea of having an efficient price signal on the runoff

rate has got a lot to do with efficient price signals for all customers and not just to do with electric heating. So I think in that respect the application focusing on electric heating wasn't helpful to get people's minds around the problem.

It was a useful example, given that we were focused on the residential runout rate, as it changed for this application and was meant to be only nothing more than that, as an example that people could relate to it. But I think it, in some respects, has not helped all the parties come to grips with what's really at stake here.

Q So I understand your point about it being a concept across rate classes, but for the residential rate class, the classes that we're talking about, the -- I think it's fair to say, or at least the assumption appears to be in the evidence, that what puts people into the runoff rate block in terms of energy use, i.e., using more than a thousand per month on average is space heating, largely?

A MR. OSLER: Well, it may be a major factor for the overall numbers, but there are a

lot of other equipments and electrical uses that can push up electrical use per customer in the residential sector that don't have to be just electric heating. So the concept of an appropriate efficiency price signal would apply to all of those uses, not just electric heating.

Q I want to take you to a table, Table 4.11 in the application. This table breaks down your calculation of the bill impacts per consumption level for residential nongovernment, use this as an example.

A MR. OSLER: Yes.

Q And, presumably, you are looking at this, people who fall under the thousand kilowatt hours per month average and below are getting -- or receiving a rate decrease as a result of the proposal?

A MR. OSLER: Yeah. If you look at the table, a couple of points. The table shows, down under "Cumulative percentage of customers," down below all the table itself; you see where I'm looking?

Q Yes.

A MR. OSLER: So it shows you that at

750 kilowatt hours a month, you are talking about, you know, 56 percent of the customers over the year in the last year of record. So the average is not a thousand; it is somewhere down in the lower level, the average use per customer. It's not a thousand kilowatt hours, it's closer to 700.

Q Sorry. I think we are at cross purposes in what I was trying to say.

If I look at that have column, "Monthly Consump. (kW.h) 1000," that is a customer who averages exactly a thousand kilowatt hours should have those bill impacts, according to your calculation?

A MR. OSLER: Yes, yeah, yes. If they exactly use that level, that's what the numbers should be.

Q What you are saying at the bottom here is that approximately 70 percent of the customers are in the 800 to 1,000 --

A MR. OSLER: Right.

Cumulative.

Q Sorry. Seventy percent of the customers are below a thousand?

A MR. OSLER: Yes, or up to a thousand,

yeah.

Q Right. And I can tell that the people that are in the 800 to 1,000 category are actually 70.1 percent minus 56.4 percent?

A MR. OSLER: Yes. And the final part of what you originally asked was, looking at this table, where does the proposal lead to a customer getting -- up to what level on this table does a customer get savings on a monthly basis from the proposal in the application. And -- if I heard you correctly.

Q Well, I was just pointing out that, for example, 1,000 -- if you hit 1,000 right on, you are saying someone in the high -- in the first zone will get a decrease of $22.26?

A MR. OSLER: Yeah.

Q I just want to make sure I was reading that correctly.

A MR. OSLER: And these numbers are all based on the bill that existed at that time.

Q Right.

A MR. OSLER: Because you can see it all on the bottom and what the rates were assumed. This is all changed now because of the Rider F, you know, et cetera.

Q I am just using it as an example of how you have done the calculation; that's fine.

A MR. OSLER: Good.

Q Now, when you say monthly consumption 1,000, is the assumption that in each and every month of the year the consumption is 1,000?

A MR. OSLER: If you were applying this to an annual number, you would have to take this and multiply it by 12. This is the monthly bill.

Q Right.

A MR. OSLER: If you said what is the effect on this on the customer for the year and you multiplied it by 12, you would be assuming that customer had 1,000 kilowatt hours each month for 12 months.

Q Which is getting to my point, which the assumption there would be that their consumption is flat?

A MR. OSLER: Yes.

Q And now we have already talked about the fact that for residential customers, one of the major factors affecting their movement into the runoff rate above a thousand is probably space heating?

A MR. OSLER: It would certainly be one factor, yes.

Q And you would agree with me that, well, space heating, almost by definition, is a weather-sensitive load?

A MR. OSLER: Yes.

Q Which means that the consumption for somebody who's using space heating over the course of the year isn't flat; it's depending on the weather?

A MR. OSLER: Correct, and there are probably other elements that deal with temperature, light availability, and everything else that would lead to variability, even if somebody didn't have space heating.

Q Okay. That means if I'm trying to look at what the annual impact of the changes are or the -- on a particular customer who has space heating, for example, I can't just take -- for example, if I look at -- let's assume, for the sake of example, and I don't know this to be accurate or not, but let's assume we are looking at someone 1,250 kilowatt hours per month average, and let's say that person is space heating. This suggests that over the course of a year,

250 kilowatt hours will occur in the second rate block, in the runoff block?

A MR. OSLER: The table itself just tells you a monthly bill. It doesn't purport to extend it to an annual bill, right?

Q Okay.

A MR. OSLER: So the table is there so you can look at it and say, If you want to assume that somebody's flat all year round, you can calculate an annual number. If you want to assume somebody's got half of the year where they are at 2,000 kilowatt hours a month on average versus the other half of the year they are only -- you can do the calculations. It's that type of use.

Q Okay. I think that's helpful to me.

So if I want to -- if I'm a customer and I am looking at this to try to figure out what my rate impact is going to be as a result of your proposed changes, I actually have to look at my winter peaking months, I guess, would be January, December, so see what my consumption is in that month to determine the maximum impact on a particular bill I'm going to get; I can't just look at my

yearly consumption?

A MR. OSLER: Right. You are right.

Q Okay.

A MR. OSLER: So these annual averages, so if you looked at the percentage of customers in each group, that's an annual average. So if we were looking at the picture for the winter months or the -- there would be a higher percentage of customers in the higher levels than you see here. And if you looked at it during the summer months, it would be the other way around. There just is a lot of different data, depending what you're trying to do.

This type of a table has been used in previous GRAs to provide customers and the Board and intervenors with an understanding of how does their monthly bill change, and then given the range of different consumption levels that might be relevant to different people, they can see how it affects them. And it's also to help the Board and intervenors understand the extent to which the rate changes are universal across all these levels or whether they are focused on certain levels of consumption.

Q Now, forgive my ignorance, but when you say continual percentage of customers, I'm assuming that you are talking about YEC residential customers, as opposed to Yukon-wide, or I'm wrong?

A MR. OSLER: No. The point was made that these are residential nongovernment customers in Yukon, YEC and YECL. They all pay this rate, and that's what this percentage is, and the same with general service, if it is in the general service.

Q Thank you for that clarification.

A MR. OSLER: Well, yeah. I mean, the -- it's effectively, on an average basis, 84 percent of the customers are consuming between 1,000 -- consuming less than 1,300 kilowatt hours a month. This proposal is saying that, you know, 84 percent of Yukon residential nongovernment customers would end up with no higher rate or a rate decrease under the proposal. That's what it's telling you.

Q I'm afraid I'm a little confused now, because it strikes me that, particularly when you're talking about the heat-sensitive load, i.e., the people using electric space heating, that

the percentage of people that fall into any particular category would depend on which month you are looking at, and I'm trying to figure out -- I can't tell that from here. This is looking at the average month, right?

A MR. OSLER: This is looking at a month when somebody is consuming that level of consumption and what their bill would be before and after the proposal.

Q Right. But the --

A MR. OSLER: The cumulative percentage of customers is looking at the average annual -- looking at all the customer bills over the 12 months and saying what percentage of those bills involve customers that didn't consume more than, say, a thousand kilowatt hours in a month over the whole year.

Q So, for example, if I look at "Monthly Consump. (kW.h) 2000" --

A MR. OSLER: Yes.

Q -- and it says 96.1 percent of customers --

A MR. OSLER: Yes.

Q -- that means that only 3.9 percent of the total annual bills were above 2,000, for example?

A MR. OSLER: Total annual bills. It means that 3.9 percent of all the bills issued to nongovernment residential customers were less than -- were over 2,000 kilowatt hours a month.

Q In the year?

A MR. OSLER: In the year. This was the year before the test year.

Q Okay. So you've got monthly consumption at the top, and then in terms of where people fall, it's based on the average -- based on the numbers for the annual?

A MR. OSLER: Right, yeah.

Q Okay. Thank you.

A MR. OSLER: If you take all of the bills that are issued in a year, each customer, if they're around the whole year and they're not temporary, some part of the year, they have 12 bills a year. So all those bills, it's telling you that 3.9 percent of them were over 2,000 kilowatt hours.

Q Okay.

A MR. OSLER: And it's telling you that all the bills issued in a year, if it's the same percentage distribution in the future test

years as it was in the last year before, of all the bills issued in a year, 84 percent of them would have a rate decrease or no change in rates under the proposal. That's what it's telling you.

Q Okay. Thank you.

I'm turning to UCG Number 30. And we asked a number of questions. And if you could skip down to the answer to (b), (c), and (d), and (i), (j), and (k) -- sorry, (f), (g), and (h). Those questions had to do with specifying the cost on one system versus the other, the WAF system versus the MD system.

And the general answer to those six questions was -- and I'll just get the exact wording here -- (quoted):

> "Yukon Energy cannot provide this information as a substantial component of YEC's costs are not functionalized and separated by system."

Do you see that?

A MR. BOWMAN: Yes.

Q So basically what I took that to mean is, when you look at the costs of the system, you don't

distinguish between, for the most part, WAF and the MD systems; you are not separating them that way?

A MR. BOWMAN: No, that's not what it says.

Q Perhaps you can explain it. This is a cost-allocation question, is it?

A MR. BOWMAN: This is exactly a cost-allocation question of the way that one would go through analyzing costs by function in preparing a cost-of-service study, the generation, transmission, and distribution broken out effectively of sort of fully loaded, if you like, so that administration costs are built into there and allocated to the function that is needed.

And in this case it asks for them broken out by system. In Yukon -- even if we had done this in -- you know, had a cost-of-service study up to date and handy and ready to go, first of all, it probably would not address all of the years there. It would be to deal with a test year. And, second, it would never break it out by system because the cost-of-service study is done on a unified

basis for Yukon.

But the form of functionalizing average cost per kilowatt hour generation would have to take into account not just an O&M budget for generation but a capital amount for generation, the debt that gets allocated to that system, the administration costs that get allocated to that system, and all those other functions, which is exactly the work of the cost-of-service study that has not been done.

Q So can I take it from that answer that once you have completed the cost-of-service study, as contemplated, for example, in your letter to YECL, May 1st, that this type of analysis will be available, this part of the product?

A MR. BOWMAN: In respect of the questions that are asked here, the average cost per kilowatt hour of generation, average cost per kilowatt hour of generation, average cost per kilowatt hour of transmission, average cost per kilowatt hour of distribution would be able to be derived from the cost-of-service study. It probably wouldn't be oriented that way for some of the things that you and I were talked

about earlier. Transmission costs are not usually thought about as a kilowatt hour type of cost. They are thought about as a peak type of cost, let's say, so kilowatt. But the data would be available to have a fully loaded functionalized cost. So in regards to the functions, yes.

In regards to doing it by system, no. And that's because a cost-of-service study for Yukon, in the way that rates are set, is done for the Yukon as a whole. It's not meant to set rates on each system on their own. In regards for having one for 2005, '06, '07, '08, and '09, no, it would be done for a year where you have a consistent set of costs between the two utilities, presumably a test year for each utility.

A MR. OSLER: Let's be very specific. We would propose it would be done for 2009, when there has been an approved revenue requirement for each utility for that full test year. Secondly, it would be a consolidated number for the two companies. It would not be separated out. And, thirdly, it wouldn't be separated out for system.

But it would be itemized as to generation, the cost that went into the generation number, the cost that went into the transmission number, and the cost that went into the distribution number. There would be tables that would show where the heck did all these numbers come from. But you couldn't trace them back even to each company unless you buried yourself in the bowels of the initial melding of the numbers.

Q So I'm just going to test my understanding a little bit. What I understand you to be saying is that the reason why, for example, you couldn't -- you wouldn't be able to separate them out into system, so WAF versus MD systems, is because the exercise that you will be going through in the cost-of-service study would be to take the costs and allocate them to customer classes and not necessarily to take -- not necessary to take your, for example, your administration costs and allocate them to the systems?

Like, you have direct costs, direct identifiable costs, that are directly attributable to the WAF system and the

MD. And to that level you have separate costs for each of the systems, but you haven't fully loaded -- you don't calculate fully loaded costs for those systems. Instead you fully load the costs to the customer classes?

A MR. OSLER: Yes. And the reasoning is that you can theoretically do this at all sorts of levels of data if you have the time and the money. That's not -- the point isn't could you do it. It isn't done because you are not trying to waste money, essentially. And the point of the cost of service is to inform parties of how consolidated costs of the two utilities affect customer -- if we looked at them by customer class, where the customers paying for those costs, or are they paying a lot less for those costs or a lot more, and perhaps to give advice on individual charges, such as demand charge versus a customer charge, although historically the charges have not tended to track what cost of service shows.

So for that reason to do what -- the job that's been assigned to people to do and to do it as cost effectively as possible, it focuses on what Mr. Bowman's

1 describing, the consolidated systems and the
2 consolidation of the two companies, because
3 that's how the rates have to be set.
4 **Q I think I understand.**
5 A MR. OSLER: Then somebody will come
6 in inevitably and ask us to do it at some
7 other, and if the Board so directs, we would do
8 it. But we wouldn't do it automatically
9 because it's costly to get more detail.
10 **Q So, for example, if the Board were convinced**
11 **that it was important to understand how one**
12 **system is more or less expensive than the other**
13 **on a fully allocated basis, that's when you**
14 **would undertake that kind of study?**
15 A MR. OSLER: Yes. And if you look
16 back on the sort of mid-1992 or '93 when there
17 was a generic cost-of-service review, some of
18 those questions were asked, and a lot of
19 different tables were produced, but we didn't
20 keep doing it for each GRA thereafter.
21 So if there was a major
22 hearing process to sort of get everybody
23 comfortable, you might have a lot more things
24 looked at than if you were just doing a regular
25 ongoing GRA.

Q Thank you.

I would like to take you to UCG Number 38(a). And you provide a table in response and the only part of it I'm actually interested, in at the moment is the qualifier at the bottom. It says (quoted):

"There are no profit sharing or incentive plans in the GRA revenue requirement."

Do you see that?

A MR. BOWMAN: Yes.

Q Does that mean -- does that mean that these numbers have been "scrubbed clean" of profit sharing or incentive plans but they do exist?

A MR. MORRISON: No.

Q Or simply --

A MR. MORRISON: They don't.

Q -- YEC doesn't have those things, YEC doesn't have profit sharing or incentive plans?

A MR. MORRISON: No. No, we don't.

Q Okay. Thank you. That was the clarification I was looking for.

At UCG Number 47, we asked about depreciation rate study, and the answer is that, to paraphrase Yukon Energy

currently has no plans to undertake a further depreciation study at this time, and you refer to the fact that the current depreciation rates were approved -- established and approved by -- in reference to the 2003 Garrett-Fleming study. Do you see that answer?

A MR. MORRISON: Yes.

Q Now, my understanding is that that same report suggested the completion of a full depreciation review should be undertaken every three to five years. Does that sound familiar?

A MR. BOWMAN: I notice that you reference it in the question from an interrogatory from McMahon-YEC-16 in the 2005 application. So I have not reread the report to see if it's indeed in the report or whether it's just in that interrogatory response. But people who do depreciation studies recommend you do depreciation studies quite often.

Q Right. So that depreciation study was done in 2003 which would put it at the five-year -- this is five years or more than when that depreciation study was done the last time; is that right?

A MR. BOWMAN: 2003.

A MR. OSLER: Well, it was done 2003 for a 2005 hearing. So the time period since the 2005 hearing isn't that long. I mean they always do it for a period earlier than the period of the hearing, because they have to use the numbers. They have to have actual numbers.

Q So it may be you may be at the three-year, you may be at the five-year range depending on when the start date is?

A MR. OSLER: Yeah.

Q So when would Yukon Energy's plans be to update it's depreciation study?

A MR. MOLLARD: We have no plans at the current time to update those.

Q UCG Number 72(b). We asked for analysis that YEC had made to verify that the miscellaneous charges within the electric service regulations are still appropriate given associated costs. And the answer was (quoted):

> "This type of analysis is not available and cannot be provided."

When was the last time that type of analysis was available and provided to the Board in support of what's in the electric service regulations?

A MR. OSLER: The miscellaneous charges you are talking about would be various items in here. The last time this was reviewed at best would be the '96-'97 GRA. I mean in the 2005 GRA, Yukon Energy addressed some specific items in here and got some changes approved for them, but they weren't the miscellaneous charges. It would be a matter that would probably -- would definitely require the involvement of the two utilities. And if the planning was going forward, it would be next addressed in the context of this upcoming Phase II review.

A MR. BOWMAN: I want to add, Mr. Buonaguro, in case that wasn't clear. The charges are in the electric service regulations, which as I say, consolidated for the two utilities, it would relate primarily to dealing with customers and customers charges. So they are actually a very small item for Yukon Energy. Most of the charges that occur in Yukon under any of these are related to Yukon Electrical, not Yukon Energy required -- because Yukon Energy deals with very few customers.

Q Okay. I will take that point, thank you.

So this is something that if it's going to be reviewed would be reviewed in connection with Yukon Electrical. So just looking at the B-13 letter, you refer to (quoted):

"...jointly proposed changes to the Electric Service Regulations (Terms and Conditions of Service)...."

Would that come under that heading?

A MR. OSLER: Yes.

Q Thank you.

I think you can tell I'm picking up the last little pieces here. UCG Number 77. At Number (a) it talks about line losses. (Quoted):

"No detailed calculation of line losses has been performed. In general terms, Yukon Energy's transmission level losses on WAF approximates 7%-8%...."

The background data that leads to the conclusion, is that on the record? Obviously that's the result of some sort of analysis.

A MR. BOWMAN: Well, it's the result of operating experience. The data required to calculate loss numbers is included in Table 2.5, and it shows that on a company as a whole it's 8.42 percent, and there's some discussion of losses by system in one of the interrogatories. And I can look that up in a minute. That would include any distribution system losses that Yukon Energy incurs related to the small amount of distribution it owns. At the transmission level, 7 to 8 percent is a number that is routinely used, and it was discussed at some length in the resource plan hearing is my recollection. I think there is even an exhibit filed in regards to it.

But certainly there is an interrogatory in the materials that deals with the losses by system.

Q Okay. Thank you.

Now, can I take you to UCG Number 81(b). And this line of questioning actually applies to a number of questions that follow it. And I think maybe once you see what I'm talking about you will understand. So UCG-81(b) we asked for confirmation (quoted):

"...that the budgets for customer extensions would be less of a contributor to YEC's revenue requirement if this budgeted amount was removed and a deferral account was established to collect actual customer extension costs as they are incurred for disposition in a subsequent year."

And the answer for this one was (quoted):

"Not confirmed. The amounts are already capital and consequently depreciated over time."

Do you see that?

A MR. OSLER: Yes.

Q So there was a series of questions after that that a very similar question and answer were given. And it was based on the idea, for example, that -- the question was based on the idea, for example, that (a), if you have a budget for 2008 of 400,000 and you have actual spending of only 84,100, the presumption was, well, if you'd used the actual, one way or another there would be savings to a customer in that example. And the answer was no.

(Quoted):

"The amounts are already capital and consequently depreciated over time."

Could you maybe explain more fully what that answer means? Because I have sort of an idea what you may mean, but I don't want to mischaracterize it.

A MR. OSLER: Could I suggest that we explain first what we do.

Q Okay.

A MR. OSLER: And then see if you have other further questions. So from the gentlemen to my right, you know, how do we actually just explain simply what we do?

A MR. MOLLARD: In any given year we'll have a varying number of customers that will show up on our door requesting service. We don't know what that number is going to be at any given year, but we are required to serve those customers, and it also varies in complexity in terms of somebody might be right next to a line or they might be quite a distance away, so we don't know what that cost is. However we are required to forecast that. That's a cost that we're going to incur. So we

1 look at our historical spending in that area
2 and come up with a number to forecast what we
3 think it will be. Now, those costs are capital
4 in nature. Generally customer connections are
5 an asset that has about a 45-year life. So we
6 will capitalize those costs on any given year,
7 and it will be added into revenue requirement
8 at a 45-year rate.
9 Q **When you say they are adding into ratebase at a**
10 **45-year rate, the critical question is what**
11 **number is put into the ratebase. And I think**
12 **what your answer to (b) means is that for 2008,**
13 **for example, even though the budget was**
14 **400,000, are you telling me that from a**
15 **ratebase perspective that doesn't matter**
16 **because what actually goes into ratebase is the**
17 **184,100 was actually spent?**
18 A MR. BOWMAN: Well, you want to be
19 careful when you talk about ratebase as opposed
20 to spending, because these are largely offset
21 by amounts the customer pays in order to be
22 connected. So these are very small amounts
23 when we get down to it. I realize just as a
24 correction 2008 we list the budget of 400,000
25 in that IR. That is actually a typo. It

should be 475,000, and you find that in Table 5.2.

The issue is that although Yukon Energy forecast to spend $475,000 on these hooking up customers, it forecast that the customers themselves would hand back 400,000 of that 475. So the total amount that would go into ratebase would be 75,000, because it's offset by customer contributions. That 75,000 that goes into ratebase would then be amortized over the life that Mr. Mollard notes. This asks for the actual spending in 2008, which was 184,000. I can also note that the actual contributions in 2008 were on the order of 130,000. So the amounts that went into ratebase in -- in actual 2008 was closer to 50,000 rather than 75,000. And that amount would be amortized over the 45 years or whatever the number that Mr. Mollard had.

Your question had gone to what if it was done using a deferral account. Well, in effect, because it's capital, it's already deferred. There is no expense of 75,000 or 50,000 in the test years. It's

amortized over that whole life.

Q That's very helpful. So I guess the critical point is whether the budget is twice as much as you spend or half as much as you spend, what actually affects rates is actuals when it gets capitalized or whatever amount gets capitalized after customer contributions as an example.

A MR. BOWMAN: Well, what is in ratebase for 2009 or 2008 is what was forecast, 475,000 to be spent, 400,000 received from the customers, a net of 75. By the time we use the next GRA, those would be trued up for actuals in ratebase the same way that 2005 numbers are here. But it's 475 to be spent offset by 400,000. The remainder is the maximum company investment that we talked about in the --

A MR. OSLER: But in addition if you are going to the bottom line how is it affecting test year 2009, whatever that number is, the net is then amortized over the life we're talking about, and only the first year of that amortization goes into 2009.

Q So just to close it off, then, to the extent that the budget amount is higher than the actual amount in the year, there would be an

increase or an increase in rates relative to that overbudgeting amount. What you are telling me is, A), that is because it's amortized over several years, that amount becomes smaller, and B), it becomes corrected at the next general rate application once the actual and the budget are reconciled?

A MR. BOWMAN: Yes, and it's only the variation in the net that matters. So as Mr. Osler noted, this GRA forecast, a net spending in 2008 of $75,000 amortized over 45 years, that's $1,500 a year plus return on 75,000. But -- so it ends up being a very small amount. Even if spending is under, because you connect less customers, it's still the net that matters. And the net as I said for '08 is still in the order to 60,000 compared to 75,000.

Q And I guess in this particular example you talked about the budget actually being 475 but then there would be an offsetting forecast of customer contributions?

A MR. BOWMAN: Correct.

Q And I am assuming that the offsetting customer contribution forecast is accounted for when you

are putting this forecasted budget into ratebase for the purposes of the -- of rates for the test years and then reconciled a few years later when you do the next GRA?

A MR. BOWMAN: Well, correct. It's at Table 5.1.

Q Okay. Thank you. So I can tell you that 82 -- UCG Questions Number 82(c), you don't have to turn them up right this second, but 82(c), 83(b), 84(c) all had very similar question and answers where you said don't worry about it; it's already capitalized. And I think your explanation would apply equally to all those questions.

A MR. BOWMAN: Well, without turning them up, I can't confirm what each of them was about. It's not any given item in capital. Not all of them have the same offsetting contributions like we talked about --

Q Right. I understand.

A MR. BOWMAN: -- for contributions. But I issue is -- the question effectively goes to deferral accounts. And rather than taking a whack of a cost in one year, can't you defer it over time to make things more stable? When you

are talking about stuff that's capital, it's not taking a whack of the cost in one year. It's already deferred over its life. So the question -- in that regard the question -- the answer would be the same.

Q Thank you. I think that was the curdle of my clarification I was looking for, thank you. In UCG-86, 87, 88, and 90 we asked you about actual expenditures for certain projects, and in each of those cases the project spending that was illustrated for 2008 was it appeared to be coming in under budget. I don't know if you want to look at an example first. Turn to Number 86. The spending in 2008 for disaster recovery plan/business continuity plan was forecast to be 150,000 in 2008 and the actual spending, it's at (b), was 73,000; do you see that?

A MR. BOWMAN: Mr. Buonaguro, yes. I have those responses. This same set of questions went from UCG-85 to 88 on a series of projects.

Q Right.

A MR. BOWMAN: Three of them, the '08 spending was below forecast in the GRA. One of

them the '08 spending was above forecast in the GRA, which was a SCADA replacement at UCG-85, and in fact that project was completed ahead of schedule. It was forecast to continue into 2009. It was completed in 2008.

Q The question --

A MR. BOWMAN: That's --

Q The question with respect to the ones that are showing underspending the simple question was are the projects themselves coming in under budget, or is the spending just deferred to 2009? Are they actually coming under budget, or is this just a matter of timing?

A MR. MOLLARD: I believe in the case of those examples that it's a deferral. The spending will still happen. It's just been pushed to later.

Q Okay. Thank you.

So maybe I can -- that is with respect to the projects referenced in Number UCG-86, 87, 88 and 90 are the ones that I think are coming in under budget, and I'll take that subject to your checking if you want to check each of those to make sure that's the case in all four. I don't want you to leave it

out there.

A MR. BOWMAN: We can confirm the first three. UCG-90 we haven't had a chance to look at. But for the first three we can confirm.

Q So do you want to look at 90 right now or do you want to take it as an undertaking? I don't need it right now.

A MR. BOWMAN: Well, I know you have got am plane so perhaps we --

Q No, no. I still have five minutes and less than five minutes of questions.

A MR. MORRISON: Mr. Buonaguro, we would have to get back to you. I can't answer that one right now.

Q That's fine. So is that just with respect to the project at UCG-90?

A MR. MORRISON: Yes.

Q Okay.

MR. BUONAGURO: Thank you. Those are my questions.

THE CHAIR: Thank you for sticking to your self-imposed time lines, and I hope that there will be some people left around for some Board questions later on as well and people don't exit as well.

And we'll take a break for lunch and we will return around 1:30.

(PROCEEDINGS ADJOURNED AT 11:54 A.M.)

(PROCEEDINGS RESUMED AT 1:33 P.M.)

THE CHAIR: Please be seated.

Just before we get started, I just wanted to put everybody on notice that it will be the Board's intent to sit later this evening, until maybe 6, 6:30, and it appears, based on estimations of cross-examination times, that that should complete our hearing. But I will have a better update at the break to see how cross-examination is going.

Mr. Landry it looks like you want to jump to your feet there.

MR. LANDRY: Yes, Madam Chair.

I just have one undertaking to deal with, and that was the undertaking to Mr. Buonaguro regarding the key performance indicator reports. I have given a copy to Ms. Lemke, a hard copy. I would ask that it be marked as the next exhibit. But I did it a little differently. Because it's a little lengthy, we emailed it to everyone,

including the Board. If somebody would like a hard copy, we can do that. But in speaking with others, they have already received it electronically, and the Board would have received it electronically. But Ms. Lemke has a paper copy that can be mark as an exhibit.

THE CHAIR: Do we have a number for that?

B-14, so marked.

Exhibit Number B-14:

Key performance indicator report.

MR. LANDRY: That is the only undertaking we have at this point in time. Hopefully before the break we will have more.

THE CHAIR: Thank you Mr. Landry.

Mr. Maissan, are you prepared to proceed?

MR. MAISSAN: Yes, I am ready.

I would like to start with, I guess, filing an exhibit. During the break this morning, I confirmed with the panel that they could access an Excel spreadsheet that they had provided as part of responses to interrogatories. It seemed it was going to be difficult. So what they did for me is make

paper copies of my notes on the subject. So I think for everyone's convenience, if we circulate this as an exhibit, when the time comes, then we can -- then we can just refer to the paper copy rather than dragging up an Excel spreadsheet.

THE CHAIR: So if I understand you correctly, it comes from an answer, an OIC answer?

MR. MAISSAN: Correct.

THE CHAIR: How would you like to mark that, Mr. Maissan, then?

MR. MAISSAN: I think from the exhibit list it would be C4-5.

MR. LANDRY: I'm fine with that, Madam Chair.

THE CHAIR: Maybe we will just mark it C4-5 for reference.

Exhibit Number C4-5:

Paper copy of OIC response.

MR. MAISSAN: The other thing I would like to say at the outset, for my convenience and probably for time saving as well, when I'm referring to interrogatories, I shall refer to the initial acronym and the final number,

instead of spelling out the long in between. So, for example, if I'm referring to Leading Edge-Yukon Energy-1-12, I would just say Leading Edge-12.

THE CHAIR: Thank you.

MR. MAISSAN: And same with the other interrogatories.

YEC PANEL QUESTIONED BY MR. MAISSAN:

Q My first question is of a general nature. From the various acronyms that are used in the application and the IRs, I had to do a fair bit of figuring to figure out what numbers belonged to what in the sense that substations are marked with an S, lines with an L and a number and so on.

I found that the line from Faro to Ross River, a 25-kV line, is referenced with two different numbers in different IRs. So I'd like to know whether that is in fact L3-56 or L3-55.

A MR. MORRISON: Perhaps, Mr. Maissan, you can tell us which two IRs so that we can check them, if you don't mind.

Q One of the . . .

A MR. MORRISON: I just want to make sure

we are talking about the same line.

Q YECL-17 is one of these, and Leading Edge-33, and YECL-18. One of those line's numbers is likely referring to the Aishihik-Haines Junction line and the other to the Faro-Ross River line, but just to keep the numbers straight.

A MR. MORRISON: Mr. Maissan, we are going to have to take a look at it and come back to you.

Q Sure. That's not a problem. And I wondered if there is a number for the new 138-kV line from Carmacks to Pelly Crossing. Is there a line number for the that or will there be?

A MR. MORRISON: I'm sure there is because we number everything, so I'll get you that as well.

Q One final comment, then, is in response to YECL-17, there is a list of substations, both by Number S and a particular number and a description of the substation. Having a list like that for lines and for plant numbers as well, we get into P numbers as well, would be convenient at future proceedings.

Could someone please explain to me what a pothead is and what it does.

A MR. MORRISON: Well, let me give you the nontechnical version of the pot -- well, you know, I guess I was going to -- never mind. I won't go there.

Q Yes. There are --

A MR. MORRISON: Let me give you the nontechnical version of what we refer to as a pothead. It is a connector for cabling.

A MR. MOLLARD: It is an electrical connector for a reactor.

Q Does Yukon Energy carry spare potheads?

A MR. MORRISON: Let me -- let me be careful -- I just want to be really specific about that. Whether -- we may have a few spare potheads because they are an old technology, if you will. And, generally, what we would do is if we had -- if we were changing them out on a -- say, on a maintenance basis, we would change it to a different kind of a connector, not a pothead.

Q Now, you anticipated my last questions, which was, Are these maintained on a regular basis or

on a preventive-maintenance basis, et cetera?

A MR. MORRISON: No. We try and maintain everything on a maintenance basis, but these are similar to -- I feel like I'm explaining something to the expert. I'm -- you know. So the -- you know, what they are is an enclosed metal connector, and so the maintenance piece on it is an infrared scan, and we do them. But if between doing the infrared scan and doing the next one you have a problem -- you can't see inside it, I guess, is my point.

Q Thank you.

These questions of course stem from the pothead failure at Aishihik that caused the outage.

A MR. MOLLARD: Correct.

Q Secondary sales, I understand that the notice period for secondary sales customers that are not SCADA connected is 24 hours; is that correct?

A MR. BOWMAN: Trying not to rely on my memory, it is 24 hours, and it would be the Secondary Sales Rate Schedule 32, which is attached to Tab 4.

Q Thank you.

And the notice period for SCADA-connected customers, of which I understand there are only one at the present time --

A MR. BOWMAN: It is stated in the same rate schedule of 15 minutes' notice.

Q Fifteen minutes, right.

Is there any possibility of the SCADA control secondary sales customers being interrupted on an instantaneous basis in a load shedding kind of format during system upsets to try to maintain the rest of the system whole?

A MR. MORRISON: Are you talking about the ones that are not connected by SCADA?

Q The ones that are SCADA connected.

A MR. MORRISON: The ones that are SCADA connected?

Q Yes.

A MR. MORRISON: I guess we could interrupt them at any time within that 15-minute period, as long as, let's say, as an example, it was in the middle of the summer and didn't need their heating system and we called them and said, Is it okay if we just turn it

off. Or B) in the winter, the 15 minutes is to give them time to switch on their alternative source of heat.

So the capability is there, but the fairness option is we have to let them turn on whatever they need to turn on.

Q Right. So I'm thinking of the situation in which there is perhaps a failure of a generating unit. I understand the system as a whole operates by a load-shedding mechanism and drops certain areas, say, Riverdale or Porter Creek or whatever to try to maintain the rest of the system whole and keep it operating, minimize the outage numbers in terms of customers interrupt, and I just wondered if secondary sales -- SCADA-controlled secondary sales had some potential to be of assistance in that?

A MR. MORRISON: I think it's very difficult to get it closer than that. You know, you are talking about the hospital, to start with, which is, you know, pretty important that we know that they've got their heat on, and I'd be loathe to even talk about

that just in the fact that what happens if they don't get their heating system on and we have got them turned off. So I wouldn't -- I wouldn't like to go there.

Q **Fair enough.**

In answer to Leading Edge-12, Yukon Energy says that (quoted):

> "...there is no reasonable temperature at which peaking diesel would be...required on a 24 hour basis."

Am I correctly interpreting this to mean that during our cold winter weather, for instance, in December through January, when the diesels were being run in the daytime, that it was still possible to sell secondary sales to a SCADA-controlled customer?

A MR. MORRISON: I guess maybe a little clarity around the question, Madam Chair.

When I look at the question and the answer, I'm not sure that -- I'm just not sure what you are asking me in relation to this question.

Q **Well, I understand that diesel -- when diesel**

peaking is required --

A MR. MORRISON: Right.

Q -- it's only required for a certain number of hours a day; it's not required 24 hours a day.

A MR. MORRISON: Right.

Q So the load drops down at night. If, for instance, from midnight until 5 a.m. diesels are not required, you have spare hydro capacity, do you in fact do some secondary sales during that nighttime window?

A MR. MORRISON: Well, it would depend. And let me say that. First of all, if we -- if we're in a situation where we have secondary sales turned off, we can certainly turn the SCADA customer back on and off.

We don't generally, because it's a manual disconnect and reconnect, we don't do that with all the other customers until we're sure we're out of the woods in terms of the peaking.

So yes, we can with a SCADA customer and yes, we would with a SCADA customer.

Q Thank you.

Could I ask you to turn

to Leading Edge-14, please.

A MR. MORRISON: Sorry, Mr. Maissan, I think Mr. Bowman would like to make a point just in addition to that answer, so if you don't mind.

A MR. BOWMAN: I was just going to say that in the type of situation you are talking about, one would also need to be attentive to what else is happening overnight. The example being, if you are in these very cold temperatures, the people operating the system are doing their best to supply all the load they can during the day with hydro so you run the least amount of diesel. One of the tools available to them is to deal with the storage at Schwatka Lake, which is a very small amount of storage.

But, nonetheless, by drawing that down some amount, you can push through a bit more water during the day in order to help meet those peaks. But you can only do that if at nighttime you are allowed to back off and let Schwatka come back up. So during those cold periods, we would have to be attentive to whether that water that one would

otherwise sell for secondary is really better used to help refill Schwatka for the next day's bit of daily peaking.

Q **Understood. Yes, I think that's also explained in another IR.**

Leading Edge-14, if you could turn to that. We were talking here about the Aishihik storage. And the answer in the second paragraph, and I should read it for everyone's benefit (quoted):

> "In regards to the test years, Yukon Energy assessed the situation where Aishihik started fall 2008 at full levels, and using forecast loads (including secondary sales) determined that even with Aishihik inflows at 50% of normal during the following 1.5 half year period (to spring 2010) Aishihik would reach its lower supply level by that time."

I understand that answer, but what I'm not sure about is the practical implications of that. Would that mean that if there were secondary sales customers available, you would continue to serve secondary sales

customers during drought period, even if it meant drawing Aishihik Lake down to its lower licence limits; i.e., at what point do secondary customers get cut off out of concern for the water storage at Aishihik?

A MR. BOWMAN: Yes, your question, if I have it right, was, If you were in the drought, would you keep making those secondary sales? And the answer is, It would have to be something that was assessed on an ongoing basis.

What we know in terms of this filing is that we were in -- making the filing in preparing the filing in the middle of 2008. We were looking forward to a future situation once Minto mine connected and the Carmacks-Stewart was up and running, that would bring the WAF system to a load level that hasn't -- in fact, has never really been experienced. The WAF system has traditionally either been Faro mine is on, you are burning 100 gigawatt hours of diesel, you are running diesel whether it is good water or bad water, basically, and so there are no secondary sales at all. Or it has been the situation where

Faro mine is off, there's a hundred gigawatt hours of surplus, so you could make secondary sales basically all the time.

We're moving into a bit of a different world going forward, which is the load is starting to get close to the long-term average amount of hydro, and we haven't really dealt with that before. So that would be sort of a preliminary comment.

In preparing the application in mid-2008 and looking forward, and this was a matter discussed somewhat in relation to the secondary sales forecast provided to the Yukon Electrical before their GRA, people have had to wrestle with the question of what happens to secondary sales.

We know that when we're making secondary sales, there is a revenue source that helps keep other ratepayers' rates down. So people want to try to keep the secondary sales on as much as possible, and of course there is a benefit to secondary sales customers who have made that investment.

At the same time you don't want to be caught in a situation where

you make some secondary sales today, at a price of 5 or 6 cents, and as a result use water that some -- at some later event you realize you could have used to displace diesel at 30 cents. That's a more difficult type of tradeoff.

And what we concluded in going through it is we're not quite at that threshold yet in 2008 needing to be able to deal with that. Looking through this application, looking forward, this application, we assessed whether secondary sales would stay on in a substantial way through 2008 and 2009 for the purposes of setting rates. We concluded that it would. We concluded that even under a very extreme water flow scenario, 50 percent of normal inflows for a sustained year and a half period, we would not today forecast an interruption to secondary sales. So we were confident that we could file the information that's here.

Now, that doesn't mean it doesn't have to be continually assessed. And if you did reach a situation where we had filed in October, and that winter it had been, you know, low in-flows and next spring there was

low in-flows and you got to summer 2009 and Aishihik was getting low, and you were looking forward to where the next water was coming from, that's where Yukon Energy will have to continually assess and decide, Is it time now to say we are approaching a situation where we need to cut off secondary sales for energy reasons.

And it is a process that people need to pay attention to. Thankfully we are not there. The water is there at Aishihik right now, so we didn't run into that situation in any event.

Q Right. So you would not automatically just run it to the low supply level, correct?

A MR. BOWMAN: No, absolutely not. The water at Aishihik gets monitored quite carefully, and this would be a key item on people's minds as they watch the water coming down.

Q Thank you.

UCG-29, could you turn to that, please.

On page 2 of 2 in the response -- or in that IR, which, under (b),

UCG-29 (b), there is a table of secondary power and for three years, 2005 through 2007, these are what I believe to be actual sales, and 2008 forecast sales; is that correct?

A MR. BOWMAN: Yes, Part (b) of the table is actuals for '05 to '07 and forecasts in '08 and '09.

Q Right.

Now, the question actually asked (quoted):

"Please provide details of the amount of surplus power available..."

as opposed to the amount of surplus power sold.

Is that information which you would have available? Because that's -- what you could sell and what you actually sold can be quite different.

A MR. BOWMAN: Yes, they can be quite different. But the question, as asked, could not be addressed or presented in a format similar to the answer that it's given. The question with respect to what could be made available if you were trying to make as much secondary power available.

And the reason is that

in -- was particularly with respect to Aishihik, we are not dealing with the run of the river plant. We are dealing with a multiyear storage, although -- or at least more than annual storage.

So what power is available in any given month is a function of how much you made available the previous month. You can only use any bit of water once.

So trying to say in May '08 there is this much available, and then go to June '08 you say, How much is available, well, it depends on whether it was used in May '08 or not. So the numbers sort of start to become very hypothetical or scenario based.

And what you really need to do is consider your load levels, what power is being used in any given month, as well as your in-flow levels, which could be anything from very low to very high in order to do that. It becomes a fairly complicated exercise very quickly, and it is a matter that has been talked about in other places here that people have put a lot of time into doing longer term water modelling to be able to figure some of

that stuff out.

It will never get you to the point where you could do a short-term type of number like this, because it depends on if it rains or not, and it depends on if you used it last month. It doesn't lend itself to a presentation of this sort.

Q So can I also assume from the information here, given the relatively low sales in the summertime, that had you had more secondary sales customers, your secondary sales could have been higher?

A MR. BOWMAN: Yes. Absolutely.

A MR. OSLER: Just for the record, UCG-8 (d) did discuss sort of the broader question of how much surplus is there versus long-term average generation, for those that are interested, because the numbers are different, as has been pointed out, from how much we sell.

And, secondly, you would have to get the load up quite a long way before the summer sales are all absorbed, as they were when we had the Anvil mine on -- Faro mine on, so that even when we're looking forward to

base-load diesel situations the next few years, some of the models that we're seeing are showing still some surplus, but it's all in the summertime when there's no customers looking for it, yet.

Q Now, one further question on secondary sales, YECL-2.

On page 3 of 5, in the paragraph underneath the table of long-term average hydro capability, and the short paragraph following that, there is a discussion about how much -- at what load there would no longer be secondary sales available. And if I understand correctly, what's being stated here is that when the overall load reaches 380 gigawatt hours a year, we would be at a point where the hydro is -- and I think this is a situation with the Aishihik third turbine in operation -- we would be in a situation where there would be no surplus hydro available essentially at any time?

The (quoted):

"...380 GW.h is consistent with a long-term average hydro capability of 356...,"

which I think is the full utilization.

A MR. BOWMAN: Yeah, no, that's not quite correct.

Q Okay.

A MR. BOWMAN: And this is -- this is a matter that we were -- we're still learning our ways to be able to talk about and explain this, because it's a fairly complicated topic.

What the response is basically saying is that when people looked at the hydro system back in '96 and '97 and the load that was on the hydro system in '96/'97, they said, How much of that load could be served by hydro, and how much should we assume diesel, at long-term average water flows, and they came up with a number of 351.

That requires some complicated modelling, and that's been a number people have used ever since. But how much your hydro system can produce is dependent on how much load you have to put on the hydro system. The more load you have, you start to squeak those last bits of energy out of those other bits of water, and so at lower load levels, your hydro system long-term average number

doesn't look very high. At really high load levels, or if we had an export market or something of that nature, it starts to come up.

What this response is saying is, it's at about 380 gigawatt hours of system load that one would calculate, through the model, that the hydro system long-term average generation is about 356, and that includes the Aishihik.

That doesn't mean that there's still no surplus or no water that could be used to generate that isn't being used to generate. If you had a load, instead of 380 gigawatt hours, if you had a tie line to British Columbia and you could sell as much power as you possibly could, you would see the generation even a little bit higher than 356.

Without that type of load or that tie line, that bit of water that you would have used just south of BC is available for secondary sales. So you could still have some summer evenings, warm summer evenings, where there is still opportunity for some secondary sales, like where Whitehorse is not using every bit of water it could running

through every turbine.

When you get to those levels, you also have to think about things like that's also the opportunity, the time when your people want to do maintenance on the unit and the like. So you are right at the margins or you are right at the edge of the system's capability.

A MR. OSLER: Let me adjust one thing, if I might.

Sitting outside Whitehorse you have got four units, and we all know that we don't sell -- we can't sell all the power that those units could generate during the summertime. As the system load goes up, we manage to sell more and more of that power that is used -- that's there in the summertime.

The secret to this answer is that the 380 gigawatt hours has recently been figured out to be the number for the system load on WAF where this long-term average, 351, is relevant. If the load is higher than that, we can get a bit more out of this existing system. If the load is lower

than that, we get a bit less, in terms of talking about useful energy that we could use to serve customers based on long-term average hydro flows.

Q **Right. Okay.**

The reason I was asking is that I recall when the Faro mine was on and our loads were in, I can't remember, 420, 430 gigawatt hours per year, on paper we required 90 gigawatt hours a year of diesel generation, and yet there were still times in the summer where we had the capability of surplus sales.

A MR. OSLER: And that's -- at times people used to say we used diesel all year round, and other times some people said we had some power in the summertime; we could never sell it. But that's the point we are getting at is that we can't store the water that's used in Whitehorse, so therefore we use it or we lose it. And if we lose it, it's because we don't have a load for it.

The load maintains the characteristics we have historically and doesn't suddenly shift. In terms of

seasonality these numbers make sense.

It also means that we have got to get more sophisticated in talking about what is the long-term average generation we can get from hydro. The answer is, it's starting to become internally now, it depends on what the load is. As Mr. Bowman says, this is a challenge for communications. So welcome the opportunity to keep trying.

Q Right.

Aishihik. The Aishihik monitoring group that was examining the results of the fisheries studies, have they made a determination yet whether they are accepting the analysis by Yukon Energy's consultant or not in respect of the health of the fishery?

A MR. MORRISON: No, they haven't, Madam Chair.

Q So at this point you don't know whether there is going to be an impact on storage range?

A MR. MORRISON: At this point, that's correct, I do not.

Q All right.

Can you tell me how the costs for these kinds of periodic studies are

recovered?

A MR. MORRISON: I'm going to -- you want to --

A MR. MOLLARD: They're included in our licencing differed costs.

Q So they are amortized over the licencing period?

A MR. MOLLARD: Over the life of the licence, yes.

Q For a study like this that was done partway through a licence, is it amortized over the remainder of the licence period?

A MR. MOLLARD: That would be correct.

Q Thank you.

I have some questions about hydro systems generation. And, in particular, I would like you to turn to YUB-29. I'm sorry. That should be YUB-31. I apologize.

A MR. MORRISON: You are disappointing Mr. Bowman. He was going to explain the graph for you.

Q I know he was keen to discuss those load duration curves. Right.

On page 2 of 3 there is a

coloured graph called "Hydro Plant Utilization." And on the left-hand axis there is a "% of Maximum." And I just wanted to confirm that the percent of maximum is based on the installed capacity as opposed to the energy available. For instance, I understand that approximately 246 gigawatt hours a year is available at Whitehorse Rapids. Installed capacity is 40 megawatts. So the full utilization of the hydro energy available through that plant would result in the utilization of 70.3 percent, as opposed to a number like 100 percent; am I correct?

YUB-31, page 2 of 3 at the top.

A MR. MORRISON: We're there.

A MR. OSLER: I don't know that there's anybody on the panel who can answer this specific question. It does say "rated capacity," and the implication is that it's based off a simple number like the plant capacity. But unless somebody knows something that -- for sure.

A MR. BOWMAN: We could put it this way: I am almost certain it is megawatts in each of

the numerator and denominator. And if that's not correct, I will come let you know -- I will come back and let us know.

Q Yeah. The point I was getting to, I guess, is it looks, from this graph, as though the Aishihik facility is being underutilized, because the numbers are relatively small, and that's really a factor of the large installed capacity and the limited water flows, i.e., energy available. So when you divide the energy available by megawatt capacity, you get a relatively low percentage utilization factor, but it is in fact a very valuable plant and fully used to the extent possible.

A MR. MORRISON: Thank you for that, Mr. Maissan.

Q Is that not correct?

A MR. MORRISON: That's correct, yes. Just for the record, so that everybody does understand how we operate Aishihik, we generally don't run Aishihik all through the summer. So basically Aishihik stores water all summer, and we operate it in the winter, which is exactly the point Mr. Maissan was getting at, is, so where it

might look like the utilization isn't 100 percent, well, if you had the plant available 12 months of the year, utilization would be a lot higher, but it's based on that six-month operation.

A MR. OSLER: And just to give why we think we know what the answer is here but we will come back to you if it isn't, if you took Aishihik and the system is fully loaded and you are looking at long-term average, it would be under 40 percent, I think, would be the utilization that you'd get.

At the moment it's not being used the same way because we don't have the same load. It's not surprising, therefore, that its utilization is quite low. It has got nothing to do with the energy available; it's just to do with the fact that plant was designed to be run that way.

Q All right. The Mayo hydro plant, could you tell me what the long-term average energy available, hydro available is from that plant, gigawatt hours per year.

A MR. BOWMAN: The Mayo plant is -- it's going through some of the same type of work we

were talking about for the WAF plant, that long-term average depends on the load you have on the system.

But in general it is -- if you have it loaded, which is not particularly difficult when you have one plant compared to when you balance two plants, it's up in the upper 30s, but we have been talking in the range of, you know, 35 to 40, but it's depending on the particular load. And that's sort of a long-term average in gigawatt hours.

And the only other comment I'll make is in the case of Mayo, given the installed capacity of the plant, it is not particularly sensitive to water flows. In very, very low in-flow years, it can't produce that much, but in average years or higher-than-average years, it doesn't pick up the extra water. The units are already fully used.

A MR. OSLER: Just so the record in the future is clear, that's the Mayo plant that exists today, which is sort of analogous to the Whitehorse situation before we built the fourth unit. The three units of Whitehorse can pretty

well take the river flow, even at its lowest level; add the fourth unit and you are into sensitivity as to all sorts of things.

If we get a Mayo B, we will be doing the same thing at Mayo that happened -- we will be roughly doubling if we keep building the capability of the plant, and it will be more sensitive to water flows.

Q In answer to PWP-18, there is an estimate of short-term incremental costs for hydrogeneration of about .5 cents per kilowatt hour. And I just wanted to understand that this .5 cents, just what goes into that .5 cents. Is that essentially the incremental maintenance cost? Does that include any allocation of operating, labour, system controls centre, insurance, water licence costs, et cetera?

A MR. BOWMAN: I'm not sure we're going to be able to answer that to a level of detail. This is a number that has been used for a long period of time. Determining the costs -- the incremental costs of operating a hydro unit to generate a kilowatt hour is not like determining the incremental costs to operate a

diesel unit to generate a kilowatt hour.

If you want to run a diesel unit and generate a kilowatt hour, you know you need the fuel to operate it, and it's reasonably easy to calculate the fuel, and then you know that you need oil changes at certain hours of intervals and the like, so that you can come up with some estimates of what it costs to generate a kilowatt hour versus not generate a kilowatt hour.

Hydro units are much, much more difficult to do that with. In any given moment the question is, How much more would it cost to take a bit of water that is otherwise going over a spillway instead of run it through a unit to produce a kilowatt hour. It's not insurance. It's not any of those types of items, because those don't vary with generation. It's not water licence fees, because those don't vary with generation.

But it's intended to capture operating and maintenance costs you incur as a result of that one bit more water going through the turbines. But this number is not something that is particularly robust,

unfortunately. It's very, very hard to estimate. It doesn't hold up very well under -- you know, the range of circumstances people could -- could come up with.

The answer, it's effectively a way of simply portraying that the incremental cost of generating a kilowatt hour with hydro is very, very low. How low it really depends on a multitude of factors.

Q **Thank you.**

Turning now to oil prices. In answer to YUB-30, YEC indicate that they do not wish to update the GRA fuel cost forecast. If fuel prices remain as they were as of January 22nd, '09, at 77 cents a litre on the WAF system, which was an answer to another interrogatory, will the Rider F become a negative rider and actually return money to ratepayers?

A MR. OSLER: If the fuel price stays below the GRA forecast price for the two utilities, the fuel rider would become negative. And in, say, the number you gave, I think was in the 70s, as you said, if it stayed --

Q Yeah, 77 cents a kilowatt hour is a number provided by Yukon Energy in response to an IR.

A MR. OSLER: Yeah. And so the GRA fuel prices in both utilities' applications are higher than that by significant degree. And, therefore, if the fuel price stayed at that level, there would -- there would be a requirement to pay the companies based on their fuel prices and give a rebate to the customers through the fuel -- Rider F until the situation changed.

Q Thank you.

A MR. OSLER: And, secondary, as well, there would be an issue of keeping track of what the price is for secondary, if the -- in the case of Yukon Energy's application, the price for secondary is also -- which is based on the last quarter of last year in terms of what was being charged to customers, is also higher than the actual price that's being paid by customers so far in 2009, first quarter, second quarter, and what we can see in the third quarter, and the price has been going down, which means that the company -- the customers, in effect, are not paying the price

that's out there, and they -- and the effect on the Rider F account would be the exact opposite. It has to, in effect, reimburse YEC for costs that it's not recovering by charging the customers and, therefore, that offset, to some extent, the rebate amount that would be paid out net through the Rider F account -- through the Rider F adjustments to customers.

Q **Thank you.**

I have some questions about peaking diesel. First of all, I'd really like to get my head around the, if there is such a thing, the definition for baseload diesel. We have talked about it in a couple of different ways, and I would really like to understand what is meant by baseload diesel.

A MR. BOWMAN: Yes, I can deal with that. The classic definition of baseload diesel in the system is when diesel is being run for energy purposes that there is an inability from the hydro system over the course of a period of time, typically a year, to be able to produce enough energy to supply the load and as a result diesel has to be run for energy purposes.

Q And whether or not that happens over a period when you need diesel anyway for peaking is immaterial, correct?

A MR. BOWMAN: Well, the classic other definition is peaking diesel, which is diesel that is run for capacity reasons, not energy reasons. And we spent some time on this, in the resource plan going through the difference between capacity and energy. There are times like now or like last December where the system did not have enough units of hydro on the system, enough wheels turning to be able to produce the instantaneous load of the system and had to run diesel. That's a demand-related quantity of diesel, and we call that -- that's classic peaking diesel. Back when the Faro mine was on and there was 100 gigawatt hours of diesel being run on the system a year, that was -- there is simply not enough water over the course of the year, so we have to run diesel to make up the difference. That's classic baseload diesel.

Somewhere between the two is a grey area as to whether you are running it for peaking or baseload. But classic baseload

diesel is wouldn't matter when you are running it, because you are simply running it to be able to hold back some water. I don't care whether they hold back that water at night or during the day. Each of them goes to keep the lake up.

A MR. OSLER: The models you used in the resource plan, you are correct. Once we got to the point where we were predicting that the energy situation demanded that we start running diesels, we started to create all of the diesel for the sake of just talking about it as baseload diesel. But we would be subject to questioning as to precision in doing that.

Q Yes. The reality of the system is that we now already require diesel peaking in extreme cold weather. If energy requirements increase more, peaking diesel requirements are likely to increase. So one could over periods of cold weather run diesels both for peaking and energy?

A MR. BOWMAN: Yes, that's correct.

Q Thank you.

Now I would like to take you to that Exhibit C4-5 which is the Excel

spreadsheet which was an attachment to YECL-23(b). It's in fact an Excel workbook with three spreadsheets in it. And I apologize for my scribbles. These are from my own notes, and I just made -- copies were just made today.

The first page in that exhibit is what is a tab called "Summary Table," the first spreadsheet. I do not have any questions on that one. But if we go to Tab 2 which is -- well, I'd like to take you to the third page in, which says across the top, "January First Part" which is a screen print from a very large Excel spreadsheet. And in the middle of the page roughly there is a column called "Max Capacity" which I believe is in megawatts, and I just wondered if somebody could confirm to me how that Number 56 was derived and whether it is in fact megawatts.

A MR. BOWMAN: Yes. Maybe I'll, just to be thorough, note the Excel file that this exhibit comes from is the response to YECL-23(b), and it was provided in Excel format with the interrogatory responses as when that response was filed.

What the question was

asking was showing detail how the secondary sales forecast was developed for the test years, but in fact as you note, there's a lot more going on in here than just the secondary sales forecast. The column that you're referencing, as you say, it's a screen shot. The first couple of columns are simply have been data that that goes into this. The first dark column is effectively a number that is an indexed amount of energy over the course of an hour that would need to be generated at some point during the month in question. This is a January month.

Q Yes, January.

A MR. BOWMAN: And what it's saying is that if -- we don't do a hourly forecast for a test year. There is a monthly forecast amount of energy, but there's not an hourly forecast. So how do you know how much peaking diesel you're going to use or how do you know how many hours you're going to have interrupted of secondary sales becomes quite a tough question.

And so what this is effectively doing is trying to say that based on what the forecast says we're going to sell

in January 2009. And based on what Januaries typically look like, starting from the highest hour to the lowest hour and ignoring what order those hours occur in, but what is the highest we tend to have in January and what's the lowest, what megawatts do we think we'd be running at any -- from highest to lowest during all of the hours in January without thinking about whether that would be on the 6th of the month or the 9th of the month. And that's what's in the 2009 forecast with secondary sales.

It compares that to a number that's 56 megawatts, max capacity as you note, which is our benchmark number for how much the hydro systems would be maxed out at before people start turning on diesels. And that number depends a bit on the water flow for the year. It depends a bit on the time of the year and how much one is drawing down Marsh Lake.

But typically when this system starts to get to the mid-50s, diesels have to start being turned on. So 56 is the number that's being used there, megawatts.

Q If we turn the page, I've had to paste the header in. This is in fact from the middle of the spreadsheet, and it's for the last part of the month of July. And I see the max capacity is still at 56 which surprised me. I expected the max capacity available in summer months to be the 40 megawatts from Whitehorse plus if you had the water available up to 30 megawatts capacity from Aishihik.

A MR. BOWMAN: Yes. I know what you are referring to there. If this sheet was being used with a particular focus on July and how the system would be dispatched over the hours in July, 56 would not be the right number. I appreciate that. At the end of the day because it seems to forecast secondary sales interruptions over the winter, it was really only five months that mattered with respect to this part of the sheet. The load duration curves that arise from the index numbers under load ration, those were used in another response, and it gives an idea of what the load duration curve in June or July or August might look like. But if you are only trying to track this portion of the page, the 56 is not a fair

number for July. It's a fair comment.

Q Thank you.

The final page of that exhibit which is the third tab in that spreadsheet, there is a column called "Secondary Sales Potential." The next column is total energy sent out, E.S.O. Can you confirm the secondary sales potential is in fact not the potential but the actual sales?

A MR. BOWMAN: No. Secondary sales potential as the term used on this sheet, the fifth page of your exhibit, is the potential in terms of the market. That is what the potential sales given the customers we have and given the loads they have and given the fact that customers don't buy all the time have a tendency to be broken down once and a while, the potential market is 22.

Q So the potential market of customers connected at this time is 22. That's not the limit of the generation capability of secondary sales at this time?

A MR. BOWMAN: Correct.

Just Mr. Osler was noting for me that you can -- you can see that when we

turn to the tab -- take you to Tab 2 numbers that of that 22 gigawatt hour potential market, Yukon Energy forecast being able to supply basically 16 of that 22. The remainder will go unserved because it will occur at times when we have to interrupt for diesel -- for running peaking diesel.

Q **In answer to Leading Edge-16, Yukon Energy states that the output of Whitehorse Rapids has varied as much as 7 megawatts from peak to low. Is this, in effect, the 24 megawatt long-term average that's sometimes talked about plus or minus 3 1/2 megawatts? Would that be a fair characterization?**

A MR. BOWMAN: It is the -- it is the generation average for the day plus or minus 3 1/2 megawatts related to the matters that we discussed in terms of overnight secondary sales being able to use Schwatka Lake and the like. It is not necessarily varying around 24.

Twenty-four megawatts is an output one can rely on depending, you know, if the -- given the water at Marsh, one can rely on 24 for the winter. In any given year it could be a bit, if not a fair bit, higher.

Q But that number would be the midpoint of the 7 megawatt range?

A MR. BOWMAN: It is not plus or minus 7. It's plus or minus 3 1/2.

Q Thank you.

At this time in terms of hydro capability, there has been no discount for possible loss of licence range due to fisheries constraints because we don't have the answer yet. And I understand from an IR that this might be in the range of I think it was 3 to 6 megawatts was quoted.

So if a third turbine -- when the third turbine is in operation, I note that it will produce an estimated 5 gigawatt hours a year additional energy from the water available. It sort of balances, I suppose, the loss from possible range of the licence. Has -- is -- was that the consideration for not making any adjustments to the long-term average energy available from Aishihik at this point in time?

A MR. OSLER: Just to be really careful here, long-term averages that we have been using change when we add in the Aishihik third

turbine, if we're looking in a forward-planning sense.

The issue that you are talking about to do with Aishihik licencing matters is that there is a constraint right now on the operation at Aishihik in the licence relating to fish issues, and I think the number you are talking about that's in an IR somewhere would probably be in gigawatt hours, not megawatts.

Q Sorry, gigawatt hours.

A MR. OSLER: Something like 386 gigawatt hours, somebody may have estimated. It may even be, you know, more than that.

But right now the long-term average that Yukon Energy can generate, if we were getting into situations where we were talking about it as a constraint, is in fact constrained by that licence. What the whole exercise of the fish studies that you were talking about is to try and see if we can use those studies to justify getting rid of that constraint so we could get back to the 351 gigawatt hours.

But if in a couple of years' time that constraint hasn't been removed and we were sitting before this Board, or even sooner, talking ability long-term averages and planning it, we would have to talk about that constraint being in place. And until it gets rid of that constraint, that's all we've got. If we got Aishihik third turbine, it still adds 5 gigawatt hours to whichever situation we're in.

It hasn't been this focal point of the attention today because that constraint, we aren't quite at that stage yet. But everything that we have been talking about is that we are getting there very soon, and those types of issues will be very much front and centre.

Q Thank you.

I have some questions about wind generation now. In answer to Leading Edge-26, Yukon Energy lists a number of difficulties to explain why the wind turbine generation has been decreasing in recent years.

Has Yukon Energy ever contacted wind turbine operating and

maintenance companies for assistance with these turbines?

A MR. MORRISON: Madam Chair, I don't have the answer to that. I would be happy to find out if the operational people have been talking to the turbine manufacturer.

Q I wasn't referring to turbine manufacturers, but to turbine operation and maintenance companies. There are copies that specialize in operating and maintaining wind farms.

A MR. MORRISON: Okay. I would be happy to find out if we have done either.

Q Thank you.

I understand from the response to Leading Edge-28 that there are no plans to bring the wind turbines under SCADA control. Do you know what it would cost to bring the turbines under SCADA control?

A MR. MORRISON: I don't have that number at my fingertips. If you would like me to --

Q Would you --

A MR. MORRISON: -- get it, I'll -- let me say this: I will see if I can get that number, you know, in the purview of these hearings. It may take some time to get that number if we

haven't done any work on it.

Q Okay. Thank you.

Given the amount of money that's being spent looking for other new renewable resources and developing them, including a potential or new expanded wind plant, do you think it would make sense to spend a little more money on these turbines and get to know how a wind plant would operate when under SCADA control?

A MR. MORRISON: I'm not sure if that makes sense or not.

Q Right.

I understand that Yukon Energy has done a prefeasibility study on wind and is looking seriously at the potential for wind energy; is this correct?

A MR. MORRISON: Yes, Madam Chair, we have. As part of our resource plan, we have followed up on all of the items that were in that resource plan that we indicated that we were going to follow up on, and we have looked at all of the -- for the most part, all of the hydro and all of the other resource options that we have.

Q On April 20th there was an article called "Wind power is not quite an energy cure-all" in the *Yukon News*. Let me quote, in part, what that says (quoted):

"When wind power goes head-to-head with hydroelectricity, there is really no competition; hydropower is easier and cheaper to produce, said Janet Patterson of the Yukon Energy Corporation."

And further down (quoted):

"Finally, she said, hydroelectricity costs 10 cents per kilowatt-hour while wind power costs 30 cents per kilowatt-hour.

'The economics just aren't there,'...."

Could you please elaborate a little bit.

A MR. MORRISON: On, what, Mr. Maissan?

Q On the -- well, two things. First of all, it appears that, from these comments, that Yukon Energy has already determined that wind energy is not competitive, and I'm surprised

that you will have done a prefeasibility study if that determination has already been made.

A MR. MORRISON: Well, I think to be clear, Madam Chair, we are talking about apples and oranges. We know the hydro business and we know what it costs to generate hydro, and we know a number of the options that we are looking at.

We also know what it costs us on calculation of kilowatt hours of output from the wind and what our costs are if we had to pay for the wind, you know, both on a capital and operating -- if you take both capital and operating costs into consideration.

And our output costs are around 30 cent a kilowatt hour. But that doesn't mean that you wouldn't go and look at a different wind option, or a series of wind options, and see whether or not those costs were going to be the same.

One of the issues -- and I'm not the wind expert; Mr. Maissan is. But one of the issues with the current wind turbines is their location. And as I understand it, part of the reason for putting

them there was a bit of an R&D because their mountain-top wind. And one of the issue we have with them is this Rime icing issue that perhaps I can be corrected on it if I'm not exactly portraying it correct. But I'm not sure anybody's really solved the problem, at least not as far as I'm aware of.

And that's an impediment or a constraint that we have with these turbines. They're not very big; they don't produce a lot of output for us. The real difficulty with wind on a go-forward basis in this system is what we need now is energy not capacity. And the energy from these from our current wind turbines is intermittent. So it's intermittent from A) the wind blowing or not blowing and B) from the operability in winter conditions of the turbines.

That doesn't mean that all wind would be -- you know, you could put all the wind into is the same category. So we looked at -- we made a commitment to look at wind options and whether or not they were feasible, and we have got a draft feasibility, and we will look at it some more. We are still

doing a little work around it. But it's not leading me to believe that we are any more competitive than -- the price might be a little bit cheaper, but not going to give us the same kind of energy we need from -- to meet system demands that hydro will.

Q Would you be prepared to table with this Board the background calculations that go into these two numbers, the 10 cent a kilowatt hour and 30 cents a kilowatt hour?

A MR. MORRISON: I will be happy to table our calculation on the wind. But I believe we have already discussed that at the previous resource plan hearing. I -- and I have a bad memory -- recall discussing that same information with the City of Whitehorse during those hearings.

Q Is this number a levelized cost of energy, the 30 cents?

A MR. MORRISON: I can't tell you that off the top of my head.

Q I would appreciate the basis for those calculations, those two calculations being provided.

THE CHAIR: Just for the record, I

have Mr. Morrison agreeing to do that.

A MR. MORRISON: Yes, sorry, I did.

THE CHAIR: Just clarifying.

Q MR. MAISSAN: I understand from the various responses about demand side management that in recent years, Yukon Energy has not contributed financially to DSM type of programs; am I correct?

A MR. MORRISON: That's correct, yes.

Q The Board has recently issued an order which requires Yukon Energy to work with Yukon Electrical on demand side management. And in answer to UCG-20, I believe Yukon Energy indicates that it is looking for further direction from the Board.

Can you please explain what direction you require from the Board to pursue DSM further?

A MR. MORRISON: Let me just say this: We will be looking for some further clarification, but not on whether or not we should undertake a joint DSM initiative with YECL. We will look for some clarity around exactly, you know, the -- I guess the breadth and depth of what we're going to do. But we have been asked by

the Board to do it; we will do that.

Q Thank you.

I believe the board order requires or asks Yukon Electrical and Yukon Energy to table their plans at the next GRA. And I suppose I am wondering when the next GRA is going to be. It seems unlikely it would be for a 2010 test year; likely to be later.

If the utilities wanted to institute, implement a DSM program prior to the next GRA being tabled, what do you think would be required from the Board?

A MR. MORRISON: Sorry, just so I'm clear, were you asking if we wanted to implement something along the DSM lines before the next GRA?

Q Correct.

A MR. MORRISON: Well, I may be wrong, but my understanding of DSM costs the last time we talked to the Board was we weren't very successful. So I would say to you at this point, in my thinking, that before we moved into a -- you know, a formal DSM program, that we would be back asking the Board whether or

not that was appropriate or not.

Q **Thank you.**

Can you turn, please, to UCG-59 (d). UCG-59 (d) asks about various things, including discouraging consumption overall or shifting demand to less costly periods, and they also talk about other things, including critical period rates.

The answer provided addresses the critical period rates but doesn't specifically talk about seasonal rates or daily rates. We already know the diesel peaking is not required for 24 hours a day. So it would seem that a daily rate, daytime rate, versus a nighttime rate might have some applicability. We also know that diesel is required in winter and not in summer, so some kind of seasonal rate may also have some kind of applicability.

Could you explain why you would not consider these kinds of options, or would you?

A MR. MORRISON: Just again so I'm clear, Madam Chair, we are talking about options that would increase our sales or options that would look at different rates for different periods

of the day from a conservation point of view?

Q We're looking generally at rate structures that would, I guess, discourage consumption during high periods and perhaps, by difference, encourage consumption during periods when hydro power is say available, i.e., encourage the summertime, discourage wintertime; discourage daytime, encourage nighttime.

And demand-side management is not just increasing or decreasing sales. It could be just shifting sales around to less costly periods.

A MR. OSLER: Right. That's -- the full concept of efficient -- encouraging efficient use includes the concept of encouraging more use when you have a surplus. So it's -- secondary sales is part of -- in many jurisdictions, part of an DSM concept.

Right now our minds are fixed on the secondary block and efficient price signals for that level of use. The concept of time-of-use pricing of some type or seasonal pricing of some type has been raised by many parties for ten or more years. It hasn't had much relevance during the period of

surplus, so the question is, Will it now have relevance as we move into the type of future we are talking about? I suspect it will be part of a discussion, so, you know, because people will raise it and we will have to examine it is the first part. It won't be dismissed out of hand.

I would just say this at the moment: In hydro-based jurisdictions, such as Manitoba or British Columbia, the time-of-use concept hasn't tended to take off to the same extent as some other jurisdictions. So to the extent that we are really relying on the grids on time of use -- sorry, on hydro based resources, we may see that it isn't really worth the effort to go through time-of-use pricing. And if you are looking at the other systems that are relying entirely on diesel, there is no particular apparent reason to think of time-of-use pricing.

So although it sounds like it's logical and we should all jump for it, there is a cost to implementing it. There is a whole bunch of rate-design issues that come with it, and I have experienced the

situation more than once, Manitoba one case, where people looked at this seriously at the industrial level and the utility level for a year, and in the end everybody came to the conclusion at that time that it just wasn't worth it.

So, you know, it wouldn't surprise me that we will talk about it, and it wouldn't surprise me if it didn't get acted on in the near term, for those types of reasons. But we weren't trying to suggest it would be dismissed out of hand in the answer here.

Q Thank you.

In Leading Edge-25 Yukon Energy says it uses electric heat itself only when available from surplus hydro. Can you confirm, then, that there is no electric heating in any of the hydro plants or other pieces of Yukon Energy equipment? For instance spillway gates and trash racks?

A MR. MOLLARD: Sorry, Mr. Maissan, just to be clear, the question refers to space heating in the plants?

Q Just let me refer to that, sorry.

Your answer provides --

talks to space heating, not to other electric forms of heating?

A MR. MOLLARD: To be clear, it says "such as space heating".

Q "Such as"?

A MR. MOLLARD: Yes. There is a qualifier there.

Q So it sounds like an example as opposed to --

A MR. MOLLARD: Yes.

Q So what you are saying is there is electric heating in trash racks and spill gates, et cetera?

A MR. MOLLARD: That is correct.

Q Thank you.

Turning now to staffing levels and Leading Edge-32. On page 2 of 6 of Leading Edge-32, at the bottom, I see in the -- sorry, you have that?

I see at the bottom of the page that through the period 2005 to 2009, in fact to 2008, the operations staff was increased from roughly 33 to about 40, which is, in round numbers, a 20 percent increase. Can somebody provide an explanation for that increase in operating staff?

A MR. MORRISON: So, Mr. Maissan, are you looking for something more than has been supplied in the answer?

Q Yes, please.

A MR. MORRISON: Can you help me out a little bit?

Q Well, you have listed the positions.

A MR. MORRISON: Yes.

Q And you go through each of them. But, you know, on a big-picture perspective, I don't understand, I guess, why the overall numbers just, you know, look really huge.

A MR. MORRISON: I'm happy to -- I'm happy to try to help you, but I'm not sure what you are looking for. You are looking for a better explanation of what we have got here? Are you looking for more? I mean, we have given you the position; we have given you the reason.

Q Yes. And each of the -- each of the explanations doesn't sound unreasonable. But when you look at the overall numbers, it seems -- it seems a very large increase.

A MR. MORRISON: Well, if you want to --

A MR. MOLLARD: Just some of the general things we think about when we look at our

staffing levels, if this is perhaps helpful, I mean, we have added significantly to our asset base in terms of kilometres in transmission line that we are dealing with. We have mentioned on a number of occasions the ages of our asset and the assets that we need to do continued maintenance on those and our reliability issues that we need to deal with.

We have new regulation all the time that we have to deal with. That doesn't speak necessarily specifically to operations, but we do have new regulatory regimes that we are having to deal with, and those sorts of things that are coming up sort of that we have to deal with and need people to deal with them, if that helps.

A MR. MORRISON: And, Mr. Maissan, sorry. Let me try to help as well too. I was just trying to look at kind of where you were zeroing in on.

Q Maybe I can help a little bit here, because the next question would be that I am surprised with the technical expansion, all the additional equipment, that in fact engineering services have gone down. And when you see is a decrease

in engineering staff with an increase in facilities and an increase in operations, I'm just wondering what's happening with those.

A MR. MORRISON: Yeah, I would suggest that part -- just excuse me for a minute.

So I just wanted to confirm that I was on the right track. I wouldn't look at it that way at all. What we have done is we have moved some people who were in engineering into operations. So it's just a structural change in that respect. So they haven't -- those tasks are still important.

We have also -- it's been very, very difficult to hire electrical engineers, specifically over this period of time that we're looking at. So some of that work is being done by contractors out of necessity, because it's been almost impossible to hire electrical engineers.

I don't know why specifically through this whole period electrical engineers, but there was a period when we were having a difficult time hiring power linemen as well. And I understand that, because it was a very busy period in the

industry, and there was lots of -- a lot of line construction and, you know, just a shortage of personnel. But just generally we have difficulty with that.

But in all this expansion, when I look at this in terms of people, it's been -- I mean, there is a number of things, and Mr. Mollard alluded to them, about additional -- not only additional facilities in terms of two large new transmission lines but we have also had a very significant increase in our load and our operation of the facilities has been on a higher level over the last number of years as well. And that also requires additional maintenance, additional capital planning, and all of those resources.

But on the regulatory side of things, we have experienced, you know, a really substantive increase in what I would call "regulatory affairs." Not just -- and I don't mean by that proceedings such as this. I mean on the environmental side the amount of permitting and environmental management issues that we have to deal with through environmental

legislation, through compliance with things like our YESAB processes and permits.

You know, we at one time thought we could deal with health and safety and environment all in one little position, and we can't deal with either one in a position barely these days. The amount of work that has to get done to comply with regulators, to comply with occupational health and safety regulations and WCB processes, as I said within environmental regulations, we can barely keep up.

In all the workload increase has been very significant for Yukon Energy. We are not a very big company. I would say to you that for a number of years the staff complements were far too low to get the work done that had to get done in order to efficiently operate the asset base that we have and to comply within the regulatory and legislative regime that we have to comply with. And that's strictly what all this is what you're seeing.

Q Thank you.

A couple of questions of

clarification on brushing. Could you tell me roughly what the total length of transmission lines were before the Carmacks-Stewart line was added.

A MR. MORRISON: We are just going to see very quickly if we have got that number.

Q In the order of 5 or 600 kilometres?

A MR. MOLLARD: I believe it's 600 including the new line.

Q And I understand from the information provided in the application that you are looking at brushing about 80 kilometres per year. Is this sort of the -- is that the brushing level that you feel is necessary on an ongoing basis to be done each year, about 80 kilometres a year to keep up?

A MR. MOLLARD: We are -- our operations personnel advises us this is sort of the leading edge of a cycle and that the 80 kilometres would represent a reasonable level in order to get caught up over the next three to four years, starting in 2009.

Q Right. Okay.

So the average frequency of brushing is, if it was 600 kilometres

divided by 80, about seven years --

A MR. MORRISON: Yes. And when I think I talk about that yesterday, Madam Chair, what we are noticing in some areas is -- and Mr. Maissan, I think, has reminded me, and I couldn't remember yesterday what year it was. We were on a seven-year cycle. We are paying attention to the brushing, and with wet conditions, we are finding that in some areas, you know, we have to look at it, you know, on a more frequent basis.

Q Yeah.

Turning briefly to return on equity. Are project capital cost overruns part of the risk that a generation/transmission utility would face?

A MR. OSLER: Could you repeat the question.

Q Yes.

Are capital -- are project capital cost overruns part of the risk that a generation utility would face -- generation and transmission utility would face?

A MR. OSLER: Well, I think generally speaking, any utility that's involved in

capital programs has a risk that the budgets that they establish for a program may experience overruns in the actual result. So, I mean, I don't think it's unique to generation and transmission utilities, except that it may be relatively more important if the generation utility and the transmission utility involved as a primary activity in capital development that is -- in development of new facilities that are very capital intensive, which would be a bit different than perhaps the relative distribution of costs within a distribution utility.

So if that's what you are getting at, in that sense it may be a bit more relevant to a generation and transmission utility that's in a development phase.

Q Right.

And in regards to the substantial capital projects that have been completed and are being anticipated, we have seen some significant levels of government funding. Do you think that in any way mitigates any of that risk?

A MR. OSLER: Well, my mind's getting

technical, but Madam Chair, the risk exists independent of the budgets that are set. The risk is that you will develop a budget that is firmly developed with all the engineering and tendering and everything else, and you then approve at the board of directors' level going forward.

So if we're talking about cost overruns in the question, I think that's the context we should assume we are talking about it in. a decision made to go forward with the right information and then experiences an overrun.

You would know what funding contributions you are going to get at that point as part of that decision, you would normally assume. The risk of an overrun is still the risk of an overrun. It isn't mitigated because somebody agreed to pay for 20 percent of your cost based on the budget.

And if I go one step further, I'd say, to the extent that you are getting a lot of contributions, it's clear that the contributors usually are not agreeing to pay for the overruns. That isn't always the

case, but it's -- it's not abnormal to assume, if you are using government as an example, that they agree to a fixed amount. They don't agree to, you know, a contingent amount, up to a certain amount, I'll put it that way.

So from a utility point of view, developing something with those types of contributions, first of all, the risk hasn't been mitigated at all by the contributor; they just contributed to reducing the total cost based on the budget, and the utility still has to deal with the risk to the total program in terms of possible overrun. I think we talked about that a bit yesterday with Mr. Keough.

Q **So an absolute amount reduction, for instance, the Phase II transmission project, if it's a $40 million budgeted project and you received contributions of 35, then the risk of going from a net cost of 5, say, to 10 million, you would view no differently as a risk of going from 40 to 45 ratepayer costs?**

A MR. OSLER: It would be the risk of going from -- having a $5 million overrun imprudently incurred costs. Because if it's not prudently incurred, there is no risk to

ratepayers; the Utility Board won't allow it to be included.

But assuming it's prudently incurred costs, the $5 million risk is a risk the utility has to observe and monitor and manage on behalf of ratepayers because nobody else is going to pick it up.

Q **All right. Thank you.**

Canada Trust note, that was talked about at length. The one thing I was a bit uncertain about was when this note becomes due in 2011, are there plans in place to refinance it with YDC, or are there any plans at all yet in place what to do with that facility when it comes due?

A MR. MORRISON: We have no firm plans on what to do with that note when it comes. We will look at financing at that time and see where we -- see where we're at.

Q **Thank you.**

In YEC's application at page 515, there is an indication that vehicle purchase in 2008 would cost $209,000, whereas in response to UCG-83, there is an indication that the actual cost, if I'm reading this

correctly, was 110,700. Is this correct? Is this the same vehicle purchase that's being referred to?

A MR. MORRISON: If you can just give us a minute.

Q Sure.

The application page 515 and UCG-83 were the two references.

A MR. MOLLARD: Just to be clear, those do refer to the same budget. I believe the application refers to service bodies. I don't believe the three units purchased were all service bodies.

The -- my recollection, subject to check, is that the -- when the forecast was done for the 2008 business plan, they -- they have to anticipate which units are going to hit their limits for replacement in a given year. And for two of the units that didn't happen, so they weren't required to be replaced.

Q All right.

I wondered whether that was a saving that was realized in 2008 and wondered whether a similar percentage of saving

could be expected in the vehicle purchase plan for 2009. And I guess I was wondering whether that is in fact related to the almost fire-sale prices available on new vehicles these days.

A MR. MOLLARD: I believe we still have the same plans as in the application to buy two service bodies, and I don't believe we're getting a deal on those.

Q Okay. Thank you.

One of the things in the capital plan as well is a tracked vehicle that is proposed to be purchased. Let me find the reference. It's in the application on page 5-16, off-road maintenance vehicle purchase. I just wanted to understand a little bit more about this vehicle.

This is a large track vehicle, something like what I think you call a digger truck, except on tracks?

A MR. MOLLARD: Its purpose built. Its brand name is a Nodwell, with a flat deck and a crane on it, so it can do similar functions to a digger-type truck.

Q Right.

And how is it moved

around if it's on tracks?

A MR. MOLLARD: Lowboy truck, truck and trailer.

Q So it requires a third party to move this?

A MR. MOLLARD: That's correct.

A MR. MORRISON: And just to add a little clarity to that, we have been renting one of those or leasing one of those vehicles for several years. And we did the -- we did an analysis, and it was clear that, you know, buying the vehicle was a much better way of going than leasing. We started out leasing it unsure of really how much use we really had for it. When we looked at the cost, buying the vehicle was a much cheaper alternative than leasing it when we needed it.

Q Yes. And it's a type of vehicle that can be used winter and summer?

A MR. MOLLARD: It is outfitted to run in the winter as well, yes.

Q I see in the specification, it's got an Arctic pack, including a 40,000 Btu cab heater. This means that even in the severe weather, if you have got transmission problems, the crew can be out and work safely from this vehicle?

A MR. MOLLARD: That's correct.

Q Have you a rough idea of what percentage of time you expect it to be in use versus on standby?

A MR. MOLLARD: I don't have that number, no.

Q In regards to the Carmacks-Stewart transmission project, in YECL-9, on page 2 of 3, there is a description of the scope changes.

A MR. MORRISON: We will get there as quick as we can.

Q Sure.

A MR. MORRISON: I think we're there, Mr. Maissan.

Q Are you there?

Yes. And there are a couple of scope reductions that are described here: one which was deferral of the Pelly Crossing substation, differed to Stage 2 and the $2 1/2 million saving, and there was also the more complex substation at Carmacks that was reduced to a switching station. And I wondered if there was a ballpark number as to the cost saving on that substation.

A MR. MORRISON: That's not a number I

have at my fingertips, Madam Chair.

Q Is that one that you could provide or ballpark?

A MR. OSLER: Not easily, because you are -- the numbers that are put in here are numbers that I'm not even sure are always met.

So if you go back to the initial cost estimates brought to this Board, Madam Chair, the substations in general were very low-budgeted amounts. The ultimate result is that the substations were considerably above even the cost estimates in the preliminary engineering.

So the amount of money that was in the initial cost estimates for whatever we were thinking we would do at Carmacks would not be a very big number, just as a common sense observation.

The bigger numbers in the original cost estimate, and they were still very small numbers, were at Minto Landing and at Pelly. And the Minto Landing number was assumed, Madam Chair, to be part of the spur line.

So when people would got to preliminary engineering stage in June of '07

and started seeing even the preliminary engineering estimates and were looking for ways to manage the budgets and everything else for Stage 1, decisions were made at that point to take the approach we took at Pelly Crossing.

I don't know that $2 1/2 million was saved in the gross sense. It sounds to me that it was somebody's estimate at that time of what it would cost at Pelly Crossing. We did incur costs as part of the package to do the work at Minto Landing. They were nowhere near 2 1/2 million, but I don't know what they were, and I don't know how we'd -- you would have to go and talk to a bunch of people to get an estimate of that.

The final costs, of course would affect this also. So it had become an analysis rather than something you just go and find. We don't have it sitting -- the decisions were made on a decision basis step by step, but they weren't necessarily all documented in a final nice way that we could discuss today.

Q And -- sorry?

A MR. MORRISON: Just to be clear,

specifically at Carmacks, one of the reasons that there is the scope changes is when we got our heads around what we really needed in terms of the operability of the system, and we had some of our -- some of the engineering people look at it and some of our engineering advisors look at it, there was a realization that they really didn't need the Carmacks substation that was previously proposed. And what we went to was a -- you know, from a design engineering point of view, was what was needed versus what somebody thought we had needed previously.

Q So there were no compromises in terms of operating the system?

A MR. MORRISON: Absolutely not.

MR. MAISSAN: Madam Chair, I estimate I probably have about half an hour left. Should we take a break at this time, or would you like to --

THE CHAIR: We had indicated we would like to have a break at 3:30. So could you try and finish up around 3:30?

MR. MAISSAN: Sure.

Q MR. MAISSAN: Minto diesels. I asked about the RPM of these units, and it wasn't

clear from the specs provided; are these 1,200 RPM units?

A MR. MOLLARD: They are high-speed units, but I can't recall off the top of my head.

Q High speed might mean 1,800 versus 1,200. Can you get back to me on that?

A MR. MOLLARD: I can get back to you.

Q The other question I have is, fuel efficiency, when they are running in baseload operation, would you have a number for that as well or could you provide that?

A MR. MOLLARD: We can get that for you.

Q All right. Thank you.

In the application on page 510, Yukon Energy says that new diesels for the Minto project would have cost an estimated 6.6 million, or 1.035 million per megawatt. Does this estimate include the issues like winterization and heating systems, more solid buildings, foundations, data connection, remote start, and visibility that are things that you needed to add to the used diesels as well? I just wondered if that comparison is an apples-to-apples comparison.

A MR. MORRISON: Sorry, Madam Chair. I'm not sure, apples comparison to what?

Q To apples -- for instance, you had to add these additional features to the used diesel units, and I wondered whether the same features were part of the 6.6 million estimate for new diesels, i.e., or would these new diesel have cost 6.36 million plus these other modifications?

A MR. MORRISON: I understand. It's my understanding, and subject to checking with my other, colleagues here, that the 1.1 per megawatt, the $1.1 million per megawatt, is for the diesels themselves. So whether they're new or old, we still have to do the other work.

Q Right. Okay. So the new diesels would have needed the same --

A MR. MORRISON: They would have needed a building. They would need all the other things that arises with that.

A MR. OSLER: And in this case of this situation, you were looking at a building and certain installations in place, you weren't creating a new diesel plant, so the rationale for that assumption isn't far off.

The question of actually figuring out how many extras you have to do for the new diesel, probably it's a bit conservative if you want to look at the number. You would have to get into more work, which wouldn't be worth doing because you've already proven that it's not cost effective.

Whereas with the other ones, you have been pushing yourself to make sure you've thought of all the little things you've got to go to get the total budget, not just the cost of whatever is the most -- the first ten things you think of.

So, if anything, if we're correct, and we'll get back to you if we're not, this number should be for the reasons you just gave a bit low for the new diesel. And if you were trying to build a new diesel plant that didn't exist, it would certainly be more than this because you'd have to spend all the money for the building and everything else. So, you know, you'd have to keep in mind the context of this estimate.

Q Sure. Thank you.

A MR. OSLER: We'll get back to you.

Q Thank you.

In Leading Edge 53, you described the process that you would go through for specifying large transformers for energy efficiency at, you know, the lowest life cycle cost, et cetera. Is this something for which you might have an example that could be provided?

A MR. MORRISON: Can you just give us a second.

Q Sure.

A MR. MORRISON: Sorry, I think in looking at the question, we have lost your question. Could you repeat it for us. It was LE-53?

Q Leading Edge 53, yes. The process for specifying transformers is described, and I wondered whether there was an example available that you could provide from a recent purchase?

A MR. MORRISON: You want to see the specifications of a transformer; is that what it is?

Q Yes. Yes. See what would have gone out to the -- to the manufacturer.

A MR. MORRISON: I guess we can provide it. We have it. We can certainly provide it.

I'm not certain how much benefit it will be for you, but . . .

Q All right.

A MR. MORRISON: We will certainly do that, if it's all right.

A MR. OSLER: But wouldn't you really -- you know, you're trying to get at how do you know what the most economical approach is taken, and you asked something about life cycle costs. Are you asking whether or not the specifications put out request the people to tell us life cycle costs? Is that what you're getting at?

Q Well, what's described here is -- well, let me just reread it and I can be more specific in my question.

You provide to the manufacturer, it says the load and no-load costs based on the kilowatts quoted to you on energy by the manufacturer. Yukon Energy uses a quoted loss bigger in the costs provided to determine the overall cost of the transformer over its life.

So what I'm looking for is just what does -- what are the numbers that

Yukon Energy provides to the manufacturer as part of requesting the quote?

A MR. MORRISON: We'll get that, Madam Chair.

Q Thank you.

Leading Edge 56 references the page 515, line 6 of the application, and it has to do with spill regulation at Whitehorse dam, and it seems to imply that a study is to be done on the spill regulation, and I wondered whether that was complete now and whether the expected expenditures in 2009 would happen as planned or whether this project has been deferred?

A MR. MORRISON: Madam Chair, this study hasn't been completed.

Q So will the anticipated $200,000 worth of work to be done in 2009 take place still this year, or --

A MR. MORRISON: I would anticipate that it would, yes.

Q So you still expect the study to be completed this year in order to do the work for this year?

A MR. MORRISON: Yes.

Q Thank you.

Question Leading Edge 58, electronic document management. This references the application page 517, line 15. And it appears that a consultant was to be hired to review the -- and assess the records management and to come up with proposed solutions, and I just wondered whether this has taken place.

Obviously from the response, that there has been no report, but I just wondered if the activity has taken place in a form other than a provision of a report?

A MR. MORRISON: No, not yet, Madam Chair.

Q Not yet, thank you.

In regards to the power line carrier system, Leading Edge Question 59 references the application page 517 and incorrectly, Madam Chair, references line 15. That should have been line 28.

I understand that Yukon Energy is replacing the Takhini to Faro power line carrier system. Do I correctly interpret that from the answer, as opposed to the Takhini-Aishihik system?

A MR. MORRISON: Sorry, Mr. Maissan, just could you repeat that again. I thought I missed the first part of it, so . . .

Q From the answer, the application proposes to replace the Takhini to Aishihik power line carrier system?

A MR. MORRISON: Right.

Q I understand from this response that that is now on hold and that the Takhini to the Faro substation is being looked at I think, including the new Carmacks-Stewart Phase I project. Is --

A MR. MORRISON: Yes, that's --

Q Is that right?

A MR. MORRISON: Thank you for that. Yes, Madam Chair, that's correct. We're having some technical questions around what is the best solution for Aishihik. We thought we had a solution working with Northwest Tel, but as it turned out, there were some technical problems more from the line of sight of Aishihik and how we get there, so we're having to reassess the options for that. That's why it's delayed, because we don't have the correct technical solution yet.

Q Is there any changes in cost due to this change in focus from one system to another?

A MR. MORRISON: Changes in cost in terms of instead of doing Takhini to Aishihik to Takhini --

Q Forecast, yes.

A MR. MORRISON: -- to Faro?

Q Now that you're --

A MR. MORRISON: I don't have that number at the top of my head, so . . .

Q Fair enough.

The next question I have is in regards to the Whitehorse-Aishihik-Faro transmission upgrades. I understand that there are these various projects described as in the application at page 518 and after that. And I was wondering whether this work is being done by contractors or by some of the Yukon Energy crews, the additional linesmen, et cetera, that have been hired?

A MR. MOLLARD: I believe that the answer is both. Some of the items specifically I can say. With respect to the insect infestation, they have to get contractors because it's a specialized technique, but the general upgrades

we'll be doing with internal crews.

Q And will your new track vehicle be in use on these projects?

A MR. MOLLARD: We're supposed to get it at the end of this month.

Q My next question is on deferred costs, and first of all, sort of a more general question. This references the application page 520. The deferred expenditures of 6.8 million are referenced here, and I understand from response to YUB-38 that this figure is now down to 4.3 million?

A MR. OSLER: YUB-38 has indicated that the number has been reduced to 4.3 million at the moment. You know, that's the more -- the most recent estimate.

Q Thank you.

Is there any capital cost range estimate for the Gladstone project? I notice it says that it's potentially very cost-effective energy, and I just wondered if there was a number you were prepared to or a range that you were prepared to mention at this time?

A MR. MORRISON: Madam Chair, no. I'm

reluctant. The reason that we would think of Gladstone as a very cost-effective project is because there's very little structural work that has to be done for the amount of gigawatt hours of potential production out of it.

So it's very early days. We have done very little work on the Gladstone project. It's one of those projects that isn't -- won't have a high capital cost just because you don't have to do a lot of work. It's the same as building a little -- it's a little control structure, a small weir.

Now, small in our terms might mean several million dollars. But, you know, if you look at it in that sense, the potential to get 18 gigawatt hours of additional energy out of the Aishihik system, I come back, you know, just in very general terms to this concept I was talking about earlier today.

If we just look at -- if we had to provide 18 gigawatt hours of energy and we could get this energy in the winter out of Aishihik, which is very valuable, and let's just say instead of getting it from the hydro

plant we had to get it from the diesel, we're talking about, you know, in the neighbourhood of $5 million to $6 million worth of diesel per year every year to generate that same 18 gigawatt hours.

So if the diversion at Gladstone costs even 10 or 12 million dollars, it's very valuable energy. It has a very quick payback. It's energy we get in the winter, which is tremendously valuable for us.

Now, technically it is not a difficult project, but it's an issue -- well, this is an issue, and Atlin and I would put Marsh in the same category, they will be very difficult to licence because they're -- they don't -- you know, the getting people to understand, you know, why we need to do these things and why we want to reverse water flows is very difficult.

There are a whole bunch of stakeholders in each of these that are involved, none of whom are particularly, you know, joyous about us going ahead and doing a project in their area where they have interest. So Gladstone will be a regulatory process that

will be very difficult, and so will Atlin from that point of view. Atlin is virtually the same kind of project. It's a small control structure on a river that controls water.

We have -- we are in the process of engaging some consultants to help us develop those projects on a technical basis and we'll have some more information. But I wanted to -- just add to this, this is about the most important thing that we do outside of, you know, our mandate of keeping a reliability and cost -- providing cost-effective electricity.

This is the long-term planning that we are mandated to do in YDC's legislation, that we are required to provide to ensure there's enough power available on the system for Yukoners. And if we don't do these things and if we can't implement some of these things, the solution is diesel, and I don't think that's our mandate.

I think our mandate is to look forward on the long term, make sure that we've got enough power at least always coming forward whether -- you know, we're not a big system. We can't be sitting out there with a

100-megawatt dam that we can just grow into because we have to pay for it.

So it's really tricky from our perspective trying to stay 5 and 10 megawatts ahead of growth because you can't build a hydro plant or you can't develop these projects as quickly as you can develop a diesel plant. So if we wait until growth catches us, that means we'll be running diesels, and so it's this very tricky balance.

And I know we talked quite a bit yesterday about the risk and who should take the risk and whether there were government contributions. Well, a big part of our strategy has been if we can get infrastructure contributions to build these projects, including Carmacks-Stewart, including Mayo B or the Aishihik project, which we have a 5 million contribution from Canada and the Yukon government to help build, those help offset that risk of the small system where we don't have very many customers, we're not connected to a big grid, and at the same time, we can get some projects into the system which don't put a lot of ratepayer -- they don't add

burden to the ratepayers. They're not coming into rates.

Thinking about the benefit of a contribution that the government and the -- and the customer Minto made to the -- keep the Minto or the Carmacks-Stewart line down to a 3 or 4 million dollar asset from the ratepayer's point of view in terms of cost, it's a benefit that the ratepayers get forever. I mean, that line is always there. It's always available to sell power over. And, you know, the ratepayers are paying 3 or 4 million dollars for it.

We have to be able to plan and find -- and we've been trying to find strategies to minimize costs to ratepayers, but one of the strategies that we feel very strongly about and is very important is the need to do these studies, the need to be looking very, very critically. And we have very critically looked at them, because if you recall, we came to you in 2005 with all of these in the resource plan and said they needed to be looked at, and we're looking at them.

We try not to overspend

on them. We try to balance what we're going to spend in one year by keeping it to a reasonable level and trying to find ways to mitigate that risk going forward with capital contributions for new projects. But these projects are absolutely some of the most important things that we're doing right now, specifically those projects.

Q Thank you. That's the next lead into my last couple of questions on Mayo B. And, you know, by comparison to these other projects you describe, and Aishihik third turbine among them, Mayo B is, you know, on a cost per megawatt and a cost per gigawatt hour per year basis, extremely expensive.

And even the Aishihik third turbine, which is principally for capacity, produces energy at, well, less than 2/3 the cost that the energy from the Mayo plant has gone to cost based on $120 million and 9 million for the third turbine.

And so I wondered whether we were really focusing on the right projects, because when you take Gladstone and Marsh and third turbine and Atlin and put them all

together, there is more energy there for Mayo and potentially for Mayo B and potentially at much lower capital cost.

And so I was just wondering about priorities of where we're spending our capital dollars, regardless of whether they are ratepayer dollars or taxpayer dollars.

A MR. MORRISON: Madam Chair, you know, it is a very valid question and very valid concern. I think we talked yesterday again about the fact that Mayo B at 100 or 120 million dollars is not a project that we could even consider going forward with without a significant capital contribution from someone else, and that at the moment is probably the Federal Government and perhaps the Yukon government in terms of assisting us to acquire the kind of dollars we need to do Mayo B.

We are very cognizant of the fact that we can't -- that Mayo B's expensive per megawatt of installed capacity if you look at it, but it has some real advantages from our point of view. A, from a hydro perspective, basically it's a brown field

development. It already has a dam. We don't have a rebuild a dam. And I would say to you that anywhere we have to think about a dam, it just adds years of regulatory time into the process.

So one of the reasons we're looking at Mayo B is we can build it quickly because the basic infrastructure is there. We have to -- we have to build a canal and a tunnel and a new powerhouse, but we already have a powerhouse, we already have an operation and an intake in that area, so yes, it's expensive. But from a regulatory point of view, it will take time, but it will take not as much time as trying to start from scratch.

The other important part about Mayo B is it's the only hydro project that we have in the development stage that can be built within the time frames that we have where we're going to -- where we anticipate or forecast we're going to need the power. So we have a lot of other hydro studies, but none of them advanced to the stage and none of the projects advanced to the stage where they're ready in a two- or three-year period to bring

online.

And that just really, really emphasizes the point I was trying to make earlier about the need to do research, the need to do planning and system studies on an ongoing basis, because we have to get some projects up to the point where they're shelf ready, and we can then take them off the shelf when we encounter these increases in load.

I mean, the best scenario is we start -- we're always in a planning mode and we always got something going forward. But the reality of it is when we brought forward the resource plan in 2005, nobody had done anything for years prior to that. So starting in 2005, we've got to this stage.

And I think you should -- we can look at that as saying that's where -- you know, it's taken us four years to get to where we're at today from starting where we were, and we can't let that happen again. We need to have the planning studies done, we need to have the information within the system, we need to spend a bit of money to make sure that when we've got new loads coming to the system

that we're not pulling out the diesel card and saying, Okay, well, let's just stick diesel on the system, because diesel isn't 20 cent a litre anymore.

And, you know, whether it's 70 or 80 cents today, you know, it's not coming back to the 20 cent level. Maybe it's not going to be 1.50, but it's certainly -- you know, it's going to be high, and ratepayers can't afford that diesel cost on the margin.

The problem with projects like Mayo is, you know, if you're in a large connected system, you know, it's a blip in BC or any place else. We're a tiny little jurisdiction. We don't have a lot of customers. So we have spent a lot of time trying to make sure if we are looking at something like Mayo B, that we're trying to get some money, enough money to make sure that, you know, we're not doing these projects in a way that's going to burden ratepayers.

And Cam might --

A MR. OSLER: I'll just add one thing to the question itself. Yukon Energy's assessment as of mid '07 was that they needed

to go out and get a priority of what they could get in terms of energy from renewable resources in the period 2010, 15 in, say, 25 to 50 million kilowatt hours range. And as we went through the next year after that, we realized that probably we should be asking the question more like 50 to 100 million kilowatt hours.

So the board of directors when we look at these matters is saying, We need all of these projects. We need the Gladstone, we need the Atlin, and we need the Mayo. And it's not that we're giving one more priority than the other. It's just that, you know, the Mayo project can be acted on in a decisive manner by doing some work and then filing an application with, yes, I've been trying to get some government funds.

The others ones are being acted on too, but they require us to go through some relatively prolonged regulatory processes that we can't predict the outcomes of. If we get through the regulatory processes in 12 months, you could probably have the facility in place at "a very simple cost." You just got

to get through Step 1.

A MR. MORRISON: And just to re-emphasize I think the point that Mr. Osler is making, we don't need Mayo or Atlin, Gladstone, Marsh. We need Mayo and all of those just to meet a very -- what I would say to you is a very conservative load forecast going forward for the next five -- four or five years, a very conservative, because it has two mines in it, that's it, one of which we know for sure and, you know, is moving ahead or we feel pretty comfortable with, and the other one is sitting there, you know, in kind of a holding pattern. But that accounts for nothing else going on in the Yukon.

And, you know, estimates I have seen even within the City of Whitehorse more recently and just a few days ago, if some of those loads happen, you know, we're going to have to add -- quickly add to those projects.

A MR. OSLER: And bottom line behind those things is in the last 12 months, we know that Minto is plaining to increase. They are going to be making their applications so that the number they are looking at right now is not

the number you should be assuming for a couple of years from now.

And there is a Faro reclamation plan that we're told will add a material amount of energy requirements to this system and will go on for some considerable number of years. So in the last 12 months, I haven't had anybody coming in telling me why we should really reduce this except for the fact that Minto's numbers when we started up were a little bit lower than we thought they were going to be given what they had told us, but they're learning like everybody else what they actually will need.

And they have to be conservative when they're talking to us, they have to make sure that we've provided enough for them, and then they'll do their best to keep it as low as possible. That's fair.

A MR. MORRISON: Just to be clear, the Faro reclamation load is as big as the Alexco mine load in the near term, and I have no idea what they're doing there, but they are doing a lot. And we're scrambling as fast as we can, but these studies are really important.

Q One final question on Mayo B. Is there a peaking capacity being installed as part of the project; i.e., will it be able to peak in wintertime with the fluctuating water levels in the four-bay Wareham Lake such as is being done at Schwatka? You are allowed to say you don't know.

A MR. BOWMAN: It's actually a bit of a complicated question, but the plant is not being designed at this point to make peaking a priority by any stretch of the imagination. And the main reason is because by the time you hook Mayo into the WAF system, which is the premise that we talked about yesterday with respect to the project, it's a relatively small plant. Even Mayo B is a relatively small plant on a relatively big system.

So you are designing the plant and figuring out installed capacity to put into it and trying to figure out the best way to make sure you're getting winter energy. There was an additional cost to trying to put in a peaking capability. The actual output or the number of megawatts you might be able to get towards a peaking capability is relatively

low in relation to the overall system. And for some other technical reasons related to the intake, it's questionable whether you could actually try to use that plant on a peaking basis.

And it's matters that the engineers are working through, but it is far and away down the list of sort of minor considerations by comparison to trying to make sure that the energy that comes out of it is maximized through the winter.

A MR. OSLER: But we are in a general sense of all the things we've been talking about, we are trying to look at the issue as part of the project of making sure we can get the best long-term average energy from the plant that's now being developed, which includes issues of storage at Mayo Lake, and I'll just leave it at that.

But it's not that we are just looking at energy and consolidating facility. We are looking at licencing issues that would allow the plant to achieve for reasonable costs the best long-term average energy, which includes some storage issues, and

Mayo Lake's the only opportunity that exists. Wareham doesn't really do that.

MR. MAISSAN: That concludes my questions, Madam Chair. Thank you for your indulgence.

THE CHAIR: Thank you, Mr. Maissan. And we will have a 15-minute break at this time.

(BRIEF ADJOURNMENT)

THE CHAIR: Thank you very much. Mr. Landry, do you have some undertakings?

MR. LANDRY: I do. Thank you, Madam Chair.

The first one I would like to deal with is -- it will be dealt with ultimately by Mr. Osler, but it's going to require the entering of an exhibit, but it is in reference to an undertaking at page 262, line 11. And it relates to, I think it was called, I don't have the transcript in front of me, but the security agreement that Mr. Marriott that talking about yesterday.

So what I will do is -- I think the best thing to do is enter it as an

exhibit now. I have given it to Ms. Lemke and people in the room. So if we could make that document as the next exhibit, with I understand to be B-15.

THE CHAIR: So marked B-15.

Exhibit Number B-15:

Answer to undertaking given to Mr. Marriott re security agreement.

MR. LANDRY: And Mr. Osler will speak to that, and then we have a couple of other undertakings we can give to the other panel members.

THE CHAIR: Thank you.

MR. LANDRY: Mr. Osler?

A MR. OSLER: Madam Chair, we were asked with respect to the flexible term note, which is in evidence. At paragraph 9 of that note, there is a reference to a security agreement mortgage, and could we find out what that was all about and what the current status of it was.

The document Exhibit B-15 is the mortgage that was registered pursuant to that paragraph 9 in the flexible term note to deal with the security with respect to that

note that the paragraph required.

The date of this document is 1993, so you can know that this was a registration that took place pursuant to the original transfer agreement when the note was still held by Canada. Yukon Development Corporation and Canada were the parties.

Since then this mortgage was in fact registered I'm told. Since then the flexible term note was purchased by Yukon Development Corporation from Canada, and at that time I'm told that this mortgage was assigned to the Yukon parties and away from Canada and has subsequently been registered in the land titles office.

MR. LANDRY: Mr. Bowman, I understand that you have a few undertakings that you can provide to the Board.

A MR. BOWMAN: Yes. Thank you.

There are two that arise from today, so I'm -- of course I don't have the transcript references for where they arise, but one was in regards to your cross-examination of Mr. Maissan just earlier today after lunch, and it was in regards to

line numbers.

And the numbers in question were line number L355. That is the number that's given to the line through Haines Junction. L356, which is the line to Ross River. And the question was whether the Carmacks-Stewart transmission project has a line number, and it does. It is L173. I believe that addresses that one undertaking from Mr. Maissan.

We also had an undertaking from Mr. Buonaguro this morning in regards to the diesel contingency fund, and it was seeking some rather older documents that set out the rules around the fund and how it operates.

And in order to complete this set, it -- I'll make reference to five documents, three of which are -- I have copies, one copy here which we can give the Board, and we'll email them out to people. They're not short documents. They are not long, but they're not -- they're submissions made that were made to this Board. And two of which are Board orders, so I'm assuming those will speak

for themselves.

The diesel contingency fund arises from the negotiated settlement in the 1996-97 GRA. So the diesel -- the negotiated settlement document itself is not a part of a Board order. And so I have a copy of that, and that will be one of the documents that we will circulate, provide a copy to Ms. Lemke and circulate. And of course that led to the order that was ultimately finalized, the 1996-97 GRA.

The diesel contingency fund, as I noted at that time, was not fully detailed in terms of some of the operating rules and the like, and that was ultimately addressed by Board Order 1999-3, and that again would be an order from the year 1999.

It is not particularly detailed in terms of what it's -- what the order itself says. The order says it accepts the documents as filed by Yukon Energy. But it references two documents filed by Yukon Energy, one a document dated June the 6th, 1999, which was a report filed by Yukon Energy, and the second was a document of October 7th, 1999,

which was additional comments filed by Yukon Energy in response to submissions received by the Board.

So it's those two other documents, the June 6th, '99, and the October 7th, '99, that set out how the fund operates, and the Board ultimately made its decision on Order 1999-3.

So those two submissions from Yukon Energy again I have a paper copy I can give Ms. Lemke, and those will be circulated in a scanned version via email and, we can make paper copies for anyone who wants them on paper the same way as the further exhibits were dealt. It be easiest to do them by email given that the size adds up.

MR. LANDRY: Perhaps, Madam Chair, to help Ms. Lemke, I just took a note of the documents, we could mark the documents as an exhibit. We will get you the hard copies now. You can put them in that way. When they come electronically, we know what exhibit numbers they have.

So if we go in the order of the documents that were referred to by

Mr. Bowman, the first one would be the settlement agreement, and which exhibit number would that be, B-16?

THE CHAIR: B-16 so marked.

Exhibit Number B-16:

Response to undertaking containing documents dated June 6, 1999, and October 7, 1999.

MR. LANDRY: The next one would be Board Order 1999-3, which would be B-17, Madam Chair?

THE CHAIR: B-17 so marked.

Exhibit Number B-17:

Board Order 1999-3.

MR. LANDRY: The next one would be the June 6th, '99, correspondence report, so that would be Exhibit B-18?

THE CHAIR: B-18 so marked.

Exhibit Number B-18:

June 6, 1999, correspondence report.

MR. LANDRY: And the last one that was referenced was an October 7th, '99, additional comments.

Exhibit B-19, Madam Chair?

THE CHAIR: B-19 so marked.

Exhibit Number B-19:

October 7, 1999, additional comments.

A MR. BOWMAN: Thank you. And then there's two more undertakings we can deal with now.

Mr. Mollard?

A MR. MOLLARD: The first item I have is dealing with an undertaking from Mr. Buonaguro this morning. He was asking regarding some capital projects. We had provided some actual spending in 2008, and he -- that was lower than the forecast in the application.

We had one we had to go back and check on, and we discovered that there was an error in the response to the interrogatory. It was UCG-YEC-1-90. The table lists the actual spending for the Aishihik water licence renewal project at 118,325. That actually should read 165,764, which is approximately the budget that we quote in the application of 167,000, so I think that addresses the undertaking.

THE CHAIR: Thank you, Mr. Mollard.

A MR. MOLLARD: I also had one other

item, the request from Mr. Maissan regarding the Minto diesels. I can confirm they are 1,800 RPM units, and the fuel efficiency is 3.7 kilowatt hours per litre.

THE CHAIR: Thank you, Mr. Mollard.

MR. LANDRY: Madam Chair, there will be just on our count a number of undertakings that will be outstanding presumably if we do finish this evening, and maybe when we can -- before we break we can just set a date by which we get the balance of the undertakings. And I don't expect that it's going to take long, but we can do that before we leave.

THE CHAIR: Certainly.

In that case, we will proceed with the Board questions.

Ms. Bentivegna, are you prepared to proceed?

MS. BENTIVEGNA: Yes. Thank you, Madam Chair.

<u>YEC PANEL QUESTIONED BY MS. BENTIVEGNA</u>:

Q Good afternoon, panel.

First I want to refer you to YUB-YEC-1-4(b), Attachment 2.

A MR. BOWMAN: I think we're there.

Q Thank you.

Now, based on that information in that attachment, it seems that YEC has paid InterGroup 3,189,000 for the years 2005 to 2008 inclusive. Now, do you believe that's correct, subject to check of course?

A MR. MOLLARD: Subject to check.

Q Thank you.

Now, of that total, 190,000 is classified as administrative. The remainder is capitalized. Now, the descriptions for the capital work implies items largely of a regulatory nature, so I'm wondering what kind of administrative services would InterGroup be providing to YEC?

A MR. MORRISON: I think Mr. Mollard will answer a little bit, but nonadministrative services are classed address administration?

A MR. MOLLARD: Yes.

A MR. MORRISON: In --

Q If you could explain.

A MR. MORRISON: Sorry. So not providing administrative services but services that were provided would be categorized within the administration category of expenses. And I

will see if my colleague Mr. Mollard can give you some details.

Q Thank you.

A MR. MOLLARD: I will just take a minute with the IR, please.

Okay. I think I can respond to this. I would classify the costs in the administration categories in two forms. On a regular basis, they would provide -- InterGroup would provide us with support for our regulatory filings, which is our annual filings due to the Board, running the regulatory model, making sure our results make sense. That would be one aspect.

The other aspect is support. What happens when we have a project such as a GRA filing, we have costs that are incurred that are included as the costs that we present to you and say, These are our actual costs for the GRA process. There's always follow-up work that comes out of Board orders, making sure that we're doing all our filings and making sure that we're complying with everything.

I can't charge those

costs to the project because the project is closed, so I spend that -- I carry that charge on my administration budget. So it would be that sort of thing on administration.

Q All right. Thank you.

Now, would YEC seeing that amount, that 3,189,000 I referred to previously, would YEC and the Yukon as a whole be better served with in-house expertise if it were developed and the resources and experience retained in the Yukon rather than consulting using a consulting group?

A MR. MORRISON: You may find that this is strictly my opinion, but my opinion, I think, based on at least my experience over the years that I have been involved in these utilities, and A, being able to hire and maintain a core of regulated -- of regulatory staff is A, a challenge in not just here, but across the North.

The second issue from my perspective is that we're -- we have not -- we have gone through a period of having basically no regulatory experience in the sense of no experience before the regulator. For years we

were never in front of the regulator. And it seems that during the period that we have gone through, the period you talk about, as we mentioned earlier, we have been here four times or five times.

So, you know, having a full-time staff that has that capacity and that ability and that expertise would be, you know, in terms of workload would, you know, in my view kind of be kind up and down.

This -- we may go through this period -- and, yes, it's been very busy. We may go through a period where we're back to, you know, every two or three years we are in front of the regulator. So we've looked at from that point of view. Have we looked at it in terms of an absolute analysis of if we could get a staff? No, we haven't done that.

The other issue that I would have is that -- that most of the -- not most. Certainly a large number of the questions that have been answered have been provided or are -- we're able to answer them because of InterGroup's continuity over the years of they know the -- they have been

involved in these hearings even though we've had different people sitting at this table from the Utilities' point of view in terms of utility staff. So they have been the one piece of continuity that we have had.

So if we think good value for the money, I think it's very good value. And could we do it with internal staff? I think it would be very, very difficult.

A MR. MOLLARD: I could also add something to that. I have had the benefit of working with another small Northern utility, and that utility did actually have a regulatory affairs group and still did rely quite heavily on consulting advice, especially for the processes that Mr. Morrison referred to.

Q And does YEC have any type of regulatory capacity, any in-house or any staff that deal with regulatory matters?

A MR. MORRISON: The only staff that we have that we would classify that deal with regulatory matters are our day-to-day accounting staff. So they certainly provide some of the input here, but it becomes very onerous on a very small accounting staff when

we start looking at the amount of work that goes into these rate filings.

Q Now, under the capitalized costs from InterGroup from 2005 to 2008, again this is the YUB-YEC-1-4, the revised attachment to, it includes work on the 20-year resource plan, the 2005 revenue requirement, the CSTP Stage 1, Minto PPA, and the 2008-2009 GRA.

And my first question is, Why are these costs not applied to a regulatory hearing account? Why is there no deferral account? Why are these costs capitalized?

A MR. MOLLARD: Sorry, in our parlance, those are what is charged to capital. That includes deferral accounts. So those charges where they reference to specifically, for example, GRAs, those are ultimately charged to deferral accounts. We only have two categories. We have admin or capital, so the deferred costs include our regulatory accounts.

Just for clarity, the CSTP is a capital project, so it would be included in our fixed assets: property, plant, and equipment.

Q Now, are you saying that when you want to use

the funds in the deferral account then you will ask the Board to use those funds as any other deferral account if we're talking regulatory costs to recover the costs out of that and to apply them against the costs that were actually allowed by the Board?

A MR. MORRISON: Ms. Bentivegna, Madam Chair, I think we just need a minute.

Q Sure.

A MR. MORRISON: I think we're getting the terminology off track here.

Q Certainly. Go ahead.

A MR. MORRISON: Ms. Bentivegna, I think we are having a debate around deferring costs versus a deferral account, so could you maybe help us a little bit here. Can you give us a little assistance as to kind of what you are looking for.

Q Certainly. Well, I mean, I can take you to each of the costs that you've put in as these capital costs that appear to refer to regulatory matters or proceedings. So, for example, and you can go to your Table 5.7. That might be of assistance.

A MR. MORRISON: It's late in the day. I

don't think our brains are working very well.

THE CHAIR: Another reason for a computer, Mr. Morrison.

A MR. MORRISON: As usual, Madam Chair, I got your message the first time.

THE CHAIR: That's debatable.

A MR. MORRISON: I know. I know. I just thought I'd make my point.

I think we're there, Ms. Bentivegna, thank you.

Q MS. BENTIVEGNA: All right. So if you look at the bottom where it say "Rate case completed," so the first amount you'll see is GRA Phase I revenue review 800,000. And I understand this to be, and it was updated in your updated amounts to over a million, that this would be costs related to this GRA?

A MR. MORRISON: Correct.

A MR. MOLLARD: That's correct.

Q So now looking at that cost, would that be considered a deferral account item over which before the money was used in that deferral account there would be Board oversight?

A MR. MOLLARD: Well, we -- if I understand correctly, we would apply to the

Board with our actual costs of which the money we spent on InterGroup to assist in the process would come to the Board for their approval to be included in that account.

Q And I guess now I've meant it to a broader question as well. All the costs, for example, that are included in your application and the updated amounts of over a million for this GRA, you mean all those costs would come to the Board and would be determined and that's what would be reflected in a deferral account for hearing costs?

A MR. MOLLARD: Yes, that's correct.

Q All right.

Now, when you estimate the 800,000, or now the million and so, of such costs, are you estimating the costs of consultants and legal services to be at the scale of costs the Board's scale of cost rate, or are these the actual charges that you estimate will be charged to you?

A MR. MOLLARD: They are intended to reflect the Board's scale of costs.

Q All right. Thank you.

Now, the next item listed

under that rate case on Table 5.7, I'm still there, it talks about YUB-2007-7 and 9 resource plan, 643,000. Now, again, is that -- was that a cost award since that's been completed, that proceeding, was that -- at that amount of 643,000, was that -- was there a cost claim, was there a cost award in that proceeding and this number reflects that?

A MR. MOLLARD: I just need to check one thing there.

Q Sure.

A MR. MOLLARD: Mr. Bowman just provided me with a reference, under Tab 6, directives, Table 6.1, the costs of the -- at page 6-8, sorry, there is a listing of the resource plan costs, PPA costs, and Part 3 costs and the respective board orders in which those costs were approved.

Q So just to confirm, those costs that are reflected here are the same as in the cost awarded by the Board and those pages that you are referring me to?

A MR. MOLLARD: Yes, that is correct.

Q Now, what about -- what is the -- I see reference to YUB-2007-8 Part 3 hearing. What

is that in reference to?

A MR. MORRISON: That --

Q Sorry. Go ahead.

A MR. MORRISON: Sorry, Madam Chair, that is the Carmacks-Stewart transmission line project energy certificate Part 3 hearing under the --

Q And does the Tab 6 at page 6 -- sorry, 6-8 also refer to the hearing costs on that?

A MR. MOLLARD: Yes, it does.

Q And they are the same as the 185?

A MR. MOLLARD: That's correct.

Q Now, I notice in your April 24th update, and still on costs, and it refers to the GRA application at page B-3 under "Administration," the third bullet, and it says (quoted as read):

"Regulatory Affairs .094 million expenses to participate in YECL hearing without seeking cost recover."

A MR. MOLLARD: Yes, I have that.

Q Now, why did you not seek cost recovery. And what I mean by that is put in a cost claim, if your intention was to put it in your hearing reserve account. I assume that that's where it's going?

A MR. MOLLARD: No, it is not in our hearing reserve account.

Q Okay.

So how are these costs different from the costs we have just spoken of?

A MR. MOLLARD: It wasn't our process, so we discussed it internally and decided that we would not put a claim in.

Q All right.

So how do you arrive, then, at the .094 million costs, and what do those reflect, and can we have a break down? Can you undertake to have a break down?

A MR. MORRISON: Madam Chair, we can certainly undertake to provide a breakdown. That would be the easiest.

Q Can you give me any indication of how that sum was arrived at?

A MR. MOLLARD: It was largely a cost associated with drafting IRs and reviewing IRs in participation of the hearing for legal counsel and consultants.

Q And again how are those costs different than the rate case?

A MR. MOLLARD: These costs are charged to our operations and maintenance budgets. They are not deferred in any fashion.

Q And though there is a mechanism, can you clarify whether those costs are according to the scale of costs?

A MR. MOLLARD: Those are actual costs, so they are what we paid.

Q All right. And would you have recovered your actual costs had you put in a cost claim?

A MR. MOLLARD: Not all of, I believe, with respect to legal. The rate would have been above the Board-approved scale of costs, so that wouldn't have been approved in total.

Q Thank you.

Then I noticed as well, in that same bullet, that it says (quoted as read):

"Legal and other services related to the Minto PPA."

And that's .078 million. Sorry. Do you see that? It's on the same page as that update. It's just under it.

A MR. MORRISON: Madam Chair, that's, just so that we're clear, and I want to make sure

that I'm clear as well on the question, but I think I am. The cost of .78 that we're talking about here is not for the Minto PPA GRA. It's not that proceeding. It's legal costs in drafting and dealing with the issues around the actual PPA document itself and dealing with Minto mine in '08 -- in 2008.

So it's not part of a regulatory -- that regulatory process.

Q Okay. That's fine. I just wanted to clarify.

Are there any other costs in your O&M that do not relate to regulatory proceedings, however are legal costs or other consulting costs other than what's listed in that 5.7?

A MR. MORRISON: Madam Chair, before my colleague Mr. Mollard answers that question, I just want to be clear, when we're talking about regulatory costs, we are talking about rate application costs?

Q That's what I want to clarify is what do you consider, because -- what do you consider rate-case costs and what do you consider regulatory costs?

A MR. MORRISON: Okay. And to me that's

important, because what I'm trying to make sure that we -- and I want to be careful. When we're talking about this proceeding or these types of proceeding or rate matters including the resource plan in the Part 3 hearing, we -- I just want to make sure that we give you an answer for that.

When you say "regulatory costs," I may have -- we may have costs related to getting a permit or something even just something entirely small operationally, but it may have a regulatory cost but not the same regulatory cost. So I'm just trying to be careful.

A MR. OSLER: And just we started with an exhibit on interim costs, and some of those costs have nothing to do with rate regulation at all or appearances before this Board. I don't know off the top of my head what portion, but a material portion deals with the other type of regulation, environmental, the filings for the two permits that have been filed for so far, one succeeded, the Carmacks-Stewart YESAB filing, and now the Minto -- the Mayo B YESAB filing, as well as a bunch of other stuff that

would not come to the Board but would be related to those projects.

Some of the -- the corporation does have regulatory staff. If you start using the word broader than we are using it at a moment, in the environmental and the permitting field, and Mr. Morrison can address that. But there may be some need to be very clear about what we're talking about.

A MR. MORRISON: So I just want to make sure I'm clear from Mr. Mollard when he is answering that question on that number, just to make sure that he's clear with you.

A MR. MOLLARD: Could you repeat the question. Sorry.

Q I wanted to know what -- how the service -- legal and other services related to the Minto PPA, how that .078 million was arrived at.

A MR. MORRISON: So the .78 related to the PPA.

A MR. OSLER: 078.

A MR. MORRISON: 078, sorry.

Is arrived at from legal costs that are related to the development, the

actual writing of the power purchase agreement.

A MR. OSLER: This is 2008 --

A MR. MORRISON: I'm sorry. Yeah. So this -- again, but it's to do with the agreement itself and costs related to working on that agreement and working with Minto on issues surrounding that agreement, but not in a regulatory proceeding is what I'm trying to get at.

Q Would it be very onerous for YEC to provide to the Board a breakout of costs, not rate case, but the regulatory costs that it has that you put under O&M for permits and matters related and other matters such as what we're talking about here?

A MR. MORRISON: For 2008-2009?

Q Yes.

A MR. MORRISON: Madam Chair, we're having a debate over here. If it's -- if it's O&M, I'm not -- we don't necessarily -- other than rate cases and major regulatory proceedings, like the YESAB process, we don't necessarily classify them as regulatory costs separate from, you know, general admin costs.

A MR. MOLLARD: I could perhaps give an

example. In my own department, within the finance group, I will have a consulting budget of, I'll say, 25,000. Now, I may spend 5,000 of that on InterGroup to assist me in my annual regulatory files as part of my normal O&M. I also may have occasion to hire an IT consultant to help with my financial information system or a local CA to help me if I need some help with a complicated accounting matter.

As a matter of practice, we don't differentiate at the budgeting stage what that 25,000 is going to be spent on. It's just budgeted as a bucket of dollars that the manager can draw on, or consulting dollars. I couldn't tell you what the split is, whether it's regulatory or IT or other matters. So that's sort of where we're struggling with the '08-'09.

A MR. MORRISON: I think probably, from my perspective, the more difficult pieces, we have a whole series of regulatory items that we deal with, and so let me use a couple of examples. And I'm just trying to think as I think through this of how difficult it might be to do what you are asking me to do, because if we could do

it, I would like to do it.

We do a series of regulatory matters that are related to our existing water licences, as an example. And we would consider those, in one sense, regulatory. And we also consider them from an O&M point of view as just admin costs. So -- or they may be capital, depending on what they are.

But what happen I'm getting at is, we have reports that we write. We have a hydrologist, an engineer, who actually spends part of his time probably doing regulatory work, but I'm not sure that we could pick all of that out of there very easily is what I'm saying.

And so those are more the kinds of examples and what Mr. Mollard was talking about. We have an environmental manager, and he does a whole series of regulatory things, including getting permits for things that we're doing on the Carmacks-Stewart line, which his time would be assigned to. But he also does diesel permits and, you know, environmental permits for things that we're doing or moving or small capital

projects. So picking it all out would -- may be very difficult. We could certainly have a very good look and see what we could give you, but I'm not certain it would be very easy to do.

THE CHAIR: Are you undertaking? I think the question was, was it too onerous.

A MR. MORRISON: We will look at that, if you don't mind.

Q MS. BENTIVEGNA: You can use your best efforts and see what --

A MR. MORRISON: See what we can do.

Q Exactly.

Leaving those costs, now going to YUB-1-3 (c) regarding the Alexco mine.

A MR. MORRISON: 1-3?

Q 1-3.

A MR. MORRISON: Thank you.

YUB-1-3?

Q Yes.

A MR. MORRISON: I'm sorry.

Q That's okay. I just didn't rattle off the whole chain.

A MR. MORRISON: I was listening to Mr. Maissan's explanation. I got the 1-3 as

13.

THE CHAIR: We should standardize this in the future.

Q MS. BENTIVEGNA: Sorry, are you there?

A MR. MORRISON: Yes, we are.

Q All right.

With the potential of the Alexco mine in 2010, are there any forecast regulatory costs in 2009 for this customer addition, including progression of the Carmacks-Stewart transmission project, Phase II.

A MR. OSLER: We are having one problem. The question seems to deal with the Carmacks Copper mine, and you are asking us about Alexco mine. So I want to be clear, before we start answering, which mine you are after.

Q It's the Alexco mine, and -- but also I'm referring to the progression of the Phase II of the Carmacks-Stewart transmission project.

A MR. OSLER: Okay. So, sorry, could you -- does it? Okay. Sorry.

Can you please repeat the question.

Q Certainly.

With the potential of Alexco mine in 2010, are there any forecast regulatory costs in 2009 for this customer addition, and then consider the progression of Phase II for the Carmacks-Stewart transmission project.

A MR. MORRISON: We're not -- we do understand your question this time.

Q Oh, good.

A MR. MORRISON: We're having a debate about whether or not they are in regulatory costs or not, and so . . .

Q I was hoping I was leaving the subject, because this question again refers to regulatory costs.

A MR. MORRISON: You are in a way.

Let me try to answer it this way: What we're doing in 2009 is negotiating a power purchase agreement with Alexco, with the view to them coming onto the system in 2010. We have some money in -- as I understand it, in that table that you previously related to, and it's $300,000, but it's offset by a customer contribution of $300,000.

So, basically, on the premise that if we are incurring some costs, they are going to have to cover the cost. So more like a spur line kind of a treatment than the main line of the Carmacks-Stewart project. Okay?

So we don't have anything other than that. I'm looking at these guys. They are not answering.

We don't have anything else other than that, so whether -- and we haven't got -- as a for instance, we haven't got funds in to do a major Carmacks-Stewart, you know, hearing or anything like that because we're just not sure on timing and where these things are going. So those would be things we'd bring at a later date.

A MR. OSLER: There are budgets -- to the best of my knowledge, there are budgets that are referred to in Tab 5 for Stage 2, Carmacks-Stewart, as well as Alexco, I guess. And I think those are what you gentlemen are looking at when you look at the schedule.

Those costs in each instance, I think, are stated to be -- assumed

to be offset by customer contributions. But not Stage 2, in the case of the line.

Beyond that I don't think anybody has broken those costs down in the GRA purposes, as developed last year, into subheadings or anything else, that I'm aware of, particularly with respect to Alexco.

Alexco, there are some issues that may involve some transformers or other things that they would pay for as well, so there is a series of different things that have to be worked out that might be a part of the cost picture.

In terms of affecting the GRA, the bottom line was that Alexco certainly didn't affect it net, and I think Carmacks-Stewart Stage 2 is only in work in progress through the test years.

Q I guess just to follow up, does this potential of the Alexco mine enhance or promote the Phase II Carmacks-Stewart transmission project?

A MR. MORRISON: It provides the prospect for some near-term benefits if the line is developed fast enough and the loads of Alexco are what we are forecasting. But it is not

determinative of whether one would go forward or not go forward with the line, for all of the reasons we have talked about.

Q All right.

And can the load for the mine be managed without construction of any new facilities? I thought I heard you just say something about a transformer or . . .

A MR. OSLER: Well, the mine -- Alexco's mine is essentially a mine and a mill at different locations, and each has to be connected into the existing system at Keno. It would be very much the nature of a normal type of connection situation where you have to add -- you do have to increase for the mill. You have to get a transformer and provide a connection.

For the mine we are busy examining exactly what it would be. It might require some upgrades to a transformer.

So in that sense there are some requirements that are being discussed from the point of view of the customer paying for them. But there is nothing like a spur line or major development of the type we had

for either Minto or we would need for Carmacks Copper.

Q All right. Thank you.

Now I would like to take you to YUB-YEC-1-12. It's regarding the Minto diesel business case.

A MR. OSLER: We are there.

Q Now, is YEC planning to continue refurbishing all the Mirrlees units?

A MR. MORRISON: Well, I think -- and Mr. Osler can jump in on this, he talked about it a little bit, I believe yesterday if not today. The part of the benefit of the Minto diesels is we can -- we can look at and delay timing on the Mirrlees units.

And the reason for refurbishing the Mirrlees and looking at the Minto diesel is to provide capacity, as we talked about. So they are there to provide the backup and the capacity on the system. So depending on the timing, whether or not we need to do Mirrlees in addition to Minto, whether we need to do Mirrlees two years from now and three years from now, is also going to depend on the load. But we would do them if we needed

additional capacity, that's for certain.

A MR. OSLER: The basic plan is still to do them. The timing of the last one is the major question mark, as discussed in the application.

Q Now, are the Minto diesels and the Mirrlees, based on the planning criteria N minus 1, are they needed? Are they both needed?

A MR. MORRISON: I'm going to -- I think while I'm going to let Mr. Osler, or perhaps Mr. Bowman, add something to this, but I just want to make sure that we're careful that when you say needed, it's when they're needed is important. So I'm going to -- based on that, I'm going to let my colleagues jump in.

A MR. OSLER: We'll do it. I'm not going to have my mind around the actual numbers, so Mr. Bowman can check on that.

But the short answer is, they are needed in the time periods that are being discussed in the application, to the best of our understanding. In the case of the sequence with the Minto and the first two Mirrlees units, it looks like they would be needed in a pretty predictable time period.

And the actual timing of the third Mirrlees unit at Whitehorse -- sorry, the Faro unit plus the two units at Whitehorse, are fairly predictable in terms of their timing, it appears. But the fourth Mirrlees unit, the third one at Whitehorse, the timing is the one issue which we are retaining some flexibility around.

I understand that they meet the tests of the criteria when we say "needed."

Do we have any other numbers we could add?

A MR. BOWMAN: Probably the easiest thing to do in respect of numbers is refer you to page 5-10, which deals with the criteria, as you say. It references in respect to the N minus 1 criteria, which is the driving criteria on the system today, and it is the one on which there is basically no debate on how to apply it.

So that has left us with some comfort as to how the criteria is to be applied for at least this time period.

The peak that was

forecast, and as noted there, for the end of 2009 effectively said, if you did the Faro Mirrlees, as is underway, and you did the first of the Whitehorse Mirrlees, WD-3, as is also underway or basically done, by the time you got to the end of 2009, you would have a surplus of three megawatts, based on the forecast at that time, if you didn't have the Minto diesels.

That is a problem, first, because the peak this last winter was about 2 megawatts higher than had been forecast; second, because if you only have a surplus of 3 megawatts, you don't have an easy ability to take out of service a 5 megawatt unit and do the work that's needed on it. Because when you take it out of service, you are driving yourself into a deficit, or you bound yourself into having to do it over the course of the summer, when the capacity is not required, with no ability to have it take longer or run into any trouble.

So the Minto diesels have provided that cushion, that flexibility, that once the Faro Mirrlees is done and the Whitehorse Mirrlees is done and we head into

2010, and the loads grow at the level that we are expecting, the second of the Whitehorse Mirrlees can be taken off-line and be refurbished in 2010 and brought online, and there wouldn't be big risk about making sure that you absolutely have to have it done for the start of winter.

As we noted, that once that unit was brought back on, you would now have a small bit of cushion on the system, and the question is how quickly that cushion gets used up. And it could get used up by increases in peak load, which we continue to be surprised by, the extent to which Whitehorse's peak load is increasing, or it could be used up by addition of other loads, or by a loss of a unit, catastrophic failure, the type of things that can happen and that this whole criteria is designed to address.

And it gives you the flexibility to then decide, do we want to incur the costs on WD-1 at a half a million a megawatt to get it back in service, or can we defer those costs, having spent a half a million a megawatt on the Minto diesels, and

save the exact same amount of money. You are no further behind. So that's what the Minto diesels do. They are needed, and they are no more expensive, and they give flexibility in respect of the criteria, the N minus 1 criteria.

Q Now, if I can refer you to -- this question deals with the 20-year resource plan. During that proceeding you will remember, because I don't have a copy of the transcript, but that YEC committed before the Board that it was going to come before the Board for projects exceeding a $3 million threshold. In light of the Board's recommendations on that issue, has YEC reconsidered this commitment? And if you will remember, the recommendation was for projects exceeding 1 million.

A MR. MORRISON: I don't know why I get the hard questions at the end of the day.

No, we haven't reconsidered it. And I guess, you know, the important part of that is trying to find a level. And let me say this: I'm probably already in trouble with the Board and the Chair about following -- following direction, but I

try to -- we try to do as best we can. With no disrespect to the $1 million level, we spent a lot of time on the $3 million level, trying to find a way to get in here with large projects where there was no requirement.

We would, I say to you this -- maybe say it this way: we would be in here -- a consideration is major projects that aren't more operational in nature than in terms of capital, and that's where we are trying to find this balance. So what's the difference between just a general -- we call "maintenance capital," which is our general capital budget that has projects in it that might be, you know, overhauling the Whitehorse 4 hydro unit on a -- which happens on a regular basis after so many hours of operation, that project could be a million dollars. Now, do I have to come to the Board to overhaul a unit because it's got to -- you know, it's houred out? I don't -- I don't think that's what the Board means either. And so we're trying to find that balance.

We're happy to make -- we're happy to try to find a number. If it's

not 3 million, is it 1? Is it 2? We're -- I think we're -- our offer of coming before the Board for 3 million was an offer to make sure that we were getting in here with major capital projects and getting them reviewed by the Board prior to us building them. But it didn't generally relate, our thinking, to operational capital items. And that's where we tried to find the balance.

Now, you know, we certainly are happy to have a discussion with the Board about that and see if we can find some definition around what it is the Board is thinking versus what we're trying to do. I don't think we have built anything in addition to what we have said that's over a million since then. I can't -- I can't think of anything where we've not come back to the Board with a project that's a million or more since that plan.

Have we rethought about it? We have. We've struggled with it. As I say, what is it that the Board is looking for us to do. And certainly we would be happy to -- and I think that was my commitment, was

major capital projects, we're happy to come into the Board, because I think it's a -- I think it's a wiser process, from our perspective, because it gives us a review of those projects and an erring of whether or not the Board looks at them in a positive light prior to us building them and then coming back and arguing the need for the project and the money.

So I think that's where we're at. You know, we haven't -- as I say, we haven't not followed the order, because we haven't built anything over a million that we haven't brought here, but we are having that struggle between how we get from our number to the Board's number and deal with those kinds of operational issues.

And Mr. Osler, I think, has a point he wants to make.

A MR. OSLER: In order for the company to be able to exercise what it's trying to do, it has to rely on the government to also provide the order in council framework for appearing before the Board, either through the type of thing we had on the resource plan,

which was setting for a hearing, or through the energy certificate route, which the government used on the Carmacks-Stewart.

And there is a series of parallel conversations and questions going on about the Minister's letter to the Board in the summer of '06, saying that the government is committed on major energy projects. And I don't know what -- I don't have the wording in front of me, to require in the future energy to be order in council declared as energy projects that would require us to come before the Board.

So in the overall context, the one comment I think we should make is we would like to find an overall framework in all of these things that would work and achieve the objectives we are talking about, however that's done. Because it requires the government, not just us, and anything we can do to facilitate that, so that there is a clear set of rules and we can all plan with.

The intent is, I think, clear, and the problem is how to execute it. And whether it's 1 million or 3 million or whether it's some other type of wording as to

what a major project is that gets around from the dollar limits, we're all open to discuss and find the vehicle that works.

Q Thank you.

Now, if I can take you to YUB-YEC-1-15.

A MR. MORRISON: I think we're there, Ms. Bentivegna.

Q Thank you.

Now, for YEC's 2005 required revenues and related matters application, YEC applied for and received approval to have its ROE based on the BCUC benchmark for a low-risk utility. The Board in Order 2009-2 directed YECL to use a similar approach in its 2008-2009 GRA compliance filing. YEC, for its 2008-2009 GRA, has applied for the same approach in determining its return on common equity.

Now, in response to Part (b) of that question, YEC responded that Board Order 2005-12 did not necessarily impose a precedent in the Yukon for the determination of return on equity. Given the direction in Order 2009-2 in YEC's current request before

this Board, is YEC satisfied that such a precedent exists for the setting of the ROE on the BCUC formula or benchmark?

A MR. OSLER: Yukon Energy would be happy if that was the Board's conclusion, that this is the process.

We know that in 2005 everybody around the table said this isn't a precedent, so that's not the issue. But now that the Board has made a determination for both utilities using the same approach, it would be good, from our point of view, if that was viewed as precedential so that we can all rely on that going forward as a simple method.

It doesn't necessarily involve all of the things that happened in British Columbia flowing from that determination. But it just simply means when we come for a GRA, we all know how we're going to determine an ROE for that GRA purposes at the moment. That's a baby step.

So if it is viewed as a precedent, Yukon Energy, as far as I'm advised, has no problem with it.

Q Thank you.

Now, is YEC requesting the Board use 8.47 percent based on the BCUC Letter L55-08 to determine YEC's ROE for 2009?

A MR. BOWMAN: The simple answer is yes. It's addressed in Exhibit B-10, page A-1 to A-2. The update that Yukon Energy filed reran the numbers for Tab 7, recalculated the revenue requirement, as was stated in the opening statement, and it's based now on an ROE of 8.47, which was the 2009 number that we calculated based on the BCUC letter for that year. And I note it is November 20th, BCUC Letter L55-08. I didn't catch if that was the same number you used, but Letter L55-08.

I apologize. Hang on one moment. I was referencing the wrong number. 8.47 is what the letter sets out for a low-risk utility. Yukon Energy's process for '08, the same it's proposing for '09, and the same it used in '05 would be -- have to adjust that for two items: One is that Yukon Energy, similar to any of the utilities, has an adder for not being the benchmark low-risk utility, and separately has an item subtracted from its ROE

pursuant to the order in council, which requires it to be lowered by one half percent. So the end result is not 8.47, it is 8.49, and it is in the same paragraph. It is at the end of the paragraph.

Q Thank you.

Now, if I can take you to YUB-YEC-1-27, part (c) of that question.

A MR. MORRISON: We are there, Ms. Bentivegna, sorry.

Q All right. Now, in that part (c) it states (quoted):

> "The development of an Independent Power Producer's policy is being addressed by the Yukon Government as part of the recently released 'Energy Strategy for Yukon.'"

What has YEC's role been in that process?

A MR. MORRISON: We haven't had any role yet in that process. I don't know whether we will have or not. But we understand there is a process.

I would like to add something to the issue, if it's helpful. We

don't have a -- I get asked this question quite often, you know, What's Yukon Energy's independent -- do we have an IPP policy. And the good news is we don't. The good news is that we don't have anything that says we can't do -- we can't entertain proposals from IPPs, and there's no rules around that you have to do this or you have to do that.

To me what that tells us is we can certainly entertain submissions or proposals from IPPs, and we would happily do that. We would happily -- be more than happy to sit down and chat with someone if they have an independent power producer proposal of any kind, and we've never had any in all the time I have been here. And we have had people come in and ask us, Is -- you know, do you have a restriction? Because they seem to think that there is a restriction. Do you have any restrictions about independent power producers hooking up to the grid? And we tell them absolutely not. If you have got a proposal and you would like to bring it to us, we would be happy to.

And particular today. To

be -- you know, to be kind of very clear, several years ago we did have a discussion with a group that said they were going to do -- they had a proposal to do a project, and I said to them, You know, we would be very happy to talk to you, but please consider this -- and this was five or six years ago: we have a surplus in hydro, and, you know, you need to consider at what price we can duplicate hydro production. So if you were looking at timing-wise, we would be glad to talk to you, bring your project forward, but right now we're probably not going to buy it if you are telling me that you are going to have something to connect to the grid today.

That's a very different story, and that was several years ago. Today if we had somebody come along and say they had an independent power producer policy, and that wasn't, in my mind, just to be clear, turning on a diesel somewhere, because we can do that, we'd be very happy to entertain them, just based on the load forecasts that we're looking at and the need to get all of those Mayo B and Atlin and Granite [*sic*] and everything else

onto the system. If somebody else has got a good idea, you know, there is nothing to stop them from coming to us, and there is nothing to stop us from entertaining.

Even without a policy, I say we have one: we would be able to talk to people.

Q Do I take from your answer that YEC hasn't at this point undertaken any demand-side management initiatives?

A MR. MORRISON: You would be correct, yes. Yes.

Q Thank you.

Now, if I could take you to YUB-YEC-1-40.

A MR. MORRISON: We are there.

Q Now, it states in that IR that (quoted):

"At the September 2007 Board of Directors meeting, this estimate had increased to $8.8 million. This amount was based on tendered cost for most major components (excluding substations). The construction decision was based on this figure, not $3.83 million. Updated economics

assessments confirmed that even with the final cost number, the project still yields Minto material cost savings over its life."

Now, are all the costs for the Minto spur paid by Minto?

A MR. MORRISON: That's correct.

Q Thank you.

Now if I can refer you, this one is CW to YEC-1-23 (a).

A MR. MORRISON: Could you repeat the number again, please.

Q Sure.

1-23 (a).

A MR. MORRISON: We are there.

Q Now, in that response you refer to (quoted):

"Professional development is a contractual obligation related to employment. The budget was used in 2005, but no activities occurred in 2006 and only limited professional development was taken in 2007. The 2008 and 2009 budgets include the expense as a required component of Yukon Energy's costs."

So my question is, What do you mean by "contractual obligations"? What type of professional development is part of a contractual obligation?

A MR. MORRISON: It -- Madam Chair, we were talking about my contract, and it's part of a -- it's in my contracted that I'm provided -- or I have an allowance for professional development training every year, and it's $15,00, and it's in here. Some years I have used it and some years I haven't.

Q That leads to my next question. Is there any assurance that the expenses will be incurred over the test years?

A MR. MORRISON: Well, to the best of my ability, I would answer that question yes. The only reason it isn't used is that I just, you know, find myself without the time to do it. And I keep getting chastised for that, but some years it's just busy. But there are plans to use it, and that's why it's there, yes.

Q Now, I want to take you to the energy project certificate for the Carmacks-Stewart transmission project Stage 1. And I did give your counsel some aids to cross so that you

have the numbers as to what was in that application.

Now, page 1 of the application for the energy certificate describes Stage 1 of the CSTP as approximately 98 kilometres of 138 kilovolt line and substations at Carmacks, Minto spur, and Pelly Crossing. Schedule 1 of that application shows the high-end costs for the project to be 25.9 million.

Now, at what point in time did YEC approach this Board for its recommendation to proceed with the project. And what I mean by that, was it at the preliminary stage or had final engineering, had it been substantially completed?

A MR. OSLER: So, essentially, as I think I said earlier, the resource plan numbers and the numbers that were used in the energy project certificate in Schedule 1, because these were the same numbers as has been used in the resource plan, just calculated to 2007 dollars and in-service dollars, those numbers were developed, obviously, by the fall, I think, of 2006, when we made an update filing

during the resource plan in November, I believe, of 2006.

They did not include preliminary, let alone final, engineering. They were estimates that had been initially developed based on information the company had. And the company's senior people visited with some engineering firms and potential people that could be involved in the design of the plan, of the development I believe in the fall of '06, and they updated the estimates at that time, and we filed an exhibit with the Board in early November that effectively reflected those new -- any new information we had in that regard at that time, and those became the numbers that we used for the resource plan hearing. And they were the same numbers that were effectively incorporated into Schedule 1 of the certificate application.

Q So then how are those numbers developed if it wasn't even with preliminary engineering? I mean, you mentioned that there was, I think you said, visiting, some people were sitting down with some people, but how can the Board rely on numbers that are in an application as to what

costs a project might be if the underlying or underpinning for those costs isn't established?

A MR. MORRISON: Well, let me talk about that for a little bit. We were -- when we came before the Board with the resource plan application and this energy certificate application, we were -- we were -- we did not allude to the veracity of these numbers being any more than what we just talked about. We were very clear that we didn't have anything more than very preliminary numbers here.

And I seem to recall a debate that we were having about whether or not we were prepared to provide certain amounts of tendering information or budgeting information, which we weren't, because we didn't want to get numbers being driven up.

We engaged some of our internal engineering staff along with external engineers to give us preliminary estimates on these costs, and that's what we brought forward were these preliminary estimates. We didn't make them up. You know, we had some engineering expertise that went out and looked at, you know, pricing, current, you know, jobs

of similar size, you know, length, wires, and substations.

But by the time we got to building these things, we were in the middle of a very heated economy that had prices going out of sight. We always committed to the Board, and to everyone else, including our own Board, and our own Board held us to those terms, is that we would not go forward on this project without tendered information. So as concrete a number as we could get.

So not just preliminary engineering and somebody doing an estimate, not final engineering and somebody doing an estimate, actual tendered costs. So we tendered the line construction, and we brought that back. And so we had -- we had what we thought were very -- you know, 80 percent certainty that our numbers were pretty good.

We still didn't get the -- I guess, the grace of an economy that, you know, kind of went along for a period of time and we were able to keep those numbers. There was a lot of inflation, a lot of prices being driven up.

But when we went forward with the project, we did not go forward except and until we had tendered numbers. And the number that we got Board approval for was $8.8 million for the spur line, not 3.8.

Now, 3.8 was what we entered into discussions with Minto with, and we told them it was very preliminary numbers, and they wanted to go ahead. We have never had them tell us stop; we don't want to do this. And we have been very, very clear. Minto, during the process of the construction of this line, got a monthly report from us, and that monthly report was comprehensive, where we were at, what was being done, what the costs were. We have -- they have been informed all along as to where this project went.

And all I can say to you is that, you know, if you have years and years and years of advance time, we could go out and we could do preliminary estimates and final estimates and tender and get all the numbers and then come in and see if we could get permission to build something, but that generally hasn't been the case. We don't have

those kinds of time lines. We built this project, brought it forward. We're happy to be -- to be scrutinized on our costs, but we are very clear about what the costs were and when we got them and what certainty we have around those numbers.

Q Now, with respect again still talking about the Carmacks-Stewart transmission project.

A MR. MORRISON: Yes.

Q We understand from the filing that the connection to Pelly Bay Crossing from Carmacks --

A MR. MORRISON: Yes.

Q -- was to be 138 kV transmission line and 138 substation, kV substation, be constructed at Pelly Crossing.

A MR. MORRISON: Right.

Q Just to clarify, did I understand correctly yesterday that you indicated that Pelly Crossing is currently connected by a line built to 138 kV transmission specification but it's energized only at 25 kV voltage?

A MR. MORRISON: That's correct. The line -- the line to Pelly Crossing is the 138-kV line, and it's just energized at a lower

level because to step it down at Pelly, it's a lot easier to be energized at 25 than it is at 138.

Q And does the decision to energize it at 25 kilovolt imply higher line losses for that segment?

A MR. MORRISON: I'd have to get back to you on that.

Q Certainly.

A MR. MORRISON: The decision to energize it at 25 is a decision -- is a practical decision of we can't -- if we're -- you could look at the project. You could look at the hookup at Pelly different ways.

We think of the project as continuing on to -- from Pelly to Stewart Crossing. So there's no point at this time of doing something different than continuing the 138 kV line from Minto Landing to Pelly. If we -- if we wanted to energize it all the way to Pelly at 138, we would have had to put in a more expensive either substation or a more expensive transformer to step it down to the small voltage that the community needs.

So it's -- I would say

that it would be cheaper to have higher line losses, if in fact we have them, and I don't know that, than to put in the equipment at Pelly that we would have to do to stop the higher line -- you know, to offset is all I am saying.

Q If you could undertake to let us know.

A MR. MORRISON: I can do that.

Q Thank you.

Now, how -- approximately how much of the total expense incurred for this project was capitalized from the generation feasibility budgets in prior years?

A MR. OSLER: There is a lot of different questions going on here about how you would define, in a practical sense, what you just asked.

There wasn't extensive feasibility study work done, from an engineering point of view, until engineers were engaged specifically on the project, and they were engaged in March of '07. So they really were all part of the last stage of the project's thrust.

The earlier costs that

were incurred that would be capitalized were costs relating to getting the YESAB permitting and appearances before the Board relating to the PPA, which is a PPA-related cost, and then I guess the certificate exercise started in late March, early April of '07.

So how much of the costs of the main line are planning costs? I'm told at construction approval they were 2.3 million, 2.4 million, and the final costs that were planning costs were 2.5 million. And we -- those are all available in LE-46 for the main line and LE-47 for the Minto spur.

So the breakdowns -- and we actually put together a table for our own sanity, and we would be happy to share it with everybody, that sort of has the spur line, the main line, and totals broken down with the different information that the -- information brought to the Board in the hearing that we just referred to, the decision of the board of directors, and the final costs, and also the contributions.

But if you wanted to get down to sort of how much is planning costs, you

have to go to the LE-46 and LE-47. It will tell you how much was at each stage. So what portion of those planning costs is really what your question is getting at, and we need clarity that -- they are all in the final -- there wasn't much spent before we were into the home stretch in 2007 is what I'm sort of suggesting.

It's a bit different when we're doing Mayo B, but it was much more engineering reporting early on.

Q You just offered to file the table?

A MR. OSLER: I would be happy to right now if you want.

Q Certainly. If you have it, we'll take it.

A MR. OSLER: It helps us keep it clear, so . . .

THE CHAIR: We have B-20. B-20 is so marked.

Exhibit Number B-20:
Stage I Carmacks-Stewart/Minto Spur Transmission Projects Initial Cost Estimates, Construction Budgets, and Final Costs ($million).

Q MS. BENTIVEGNA: Now, because of the scope

changes in the Carmacks-Stewart Transmission Stage 1, is it fair to compare actual costs to forecast costs in the energy certificate application for this project?

A MR. OSLER: I take it you're referring to all of the scope changes we're talking about. And then there would be the ones that we have highlighted and that have increased the costs, the requirements for a different route in one portion of the line and things like that.

Q And changes to the substation and --

A MR. OSLER: And the other type of changes were changes to the substation, particularly the one at Pelly, because that was part of the main line. And in that sense if you were doing a full, you know, apples-to-apples comparison, you have to take account of those changes.

The estimate in the original budget for substations for the main line was 1.9 million I gather from LE-46. The preliminary engineering which would have reflected the changes in scope reduced that to 1.65 million by the time the board of directors

made a decision in the fall of '07.

I can't tell you from this information how much the preliminary engineering would have estimated the change due to the change in the substations. I can only tell you that type of information from what's here. It probably -- the difference between the two probably understates the degree to which the substation change at Pelly reduced the cost.

Neither one of those two estimates, the original estimate or the construction approval estimate, includes provision for the changes that came from the YESAB process. I could tell you that much, which is the other type of scope.

I don't think the Carmacks substation changes were all that material, but I can't tell you anything about that from this -- you know, Carmacks versus Pelly. I would -- I would assume from my information that the big changes in substation scoping related to the Pelly Crossing substation.

Q Thank you.

Now, I know there has been a lot of talk about Rider F, but I still have a few questions of clarification. Now, is fuel price the only trigger to Rider F?

A MR. OSLER: I'm sorry?

Q Oh, Rider F.

A MR. OSLER: Yes. What was --

Q Is fuel price the only trigger?

A MR. OSLER: Trigger?

Q Or are there other triggers that will trigger the Rider F coming into play when there's a collection or a refund?

A MR. BOWMAN: Well, the Rider F is the means by which ratepayers are charged or credited amounts that are in the deferred fuel price account for the two companies. So the changes in the Rider F or updates to the level of Rider F, implementation of the rider were at zero today, if it were to change, the trigger is in fact effectively the balance in the account and where the companies see it going.

When they implement a change to Rider F, it's based on the two companies getting together, saying the balance is not tracking, you know, within a range that

1 people are satisfied with, and over the next
2 12 months, we see it going in a direction that
3 will not keep the account at a low balance, so
4 we'll implement a rider to aim to bring us back
5 to zero within 12 months.
6 So, in fact, the trigger
7 is effectively the balance in the account, if
8 you'd like. Now, of course one level deeper,
9 the balance in the account arises because of
10 transactions that the utilities make with their
11 respective fuel price accounts. In the case of
12 Yukon Electrical, that's solely related to fuel
13 price. In the case of Yukon Energy, it's
14 related to both fuel price that -- for fuel
15 that's consumed and variations in the secondary
16 sales rate as was approved by this Board in
17 '05, so it's actually those two factors.
18 A MR. OSLER: Can I just make one
19 addition in the history sense. There is an odd
20 thing in Yukon -- the order in council's --
21 going way back in the order in council in
22 95-90. Clause 8 requires that a fuel price
23 adjustment be put there, so that's why we don't
24 come to the Board for approval of each one of
25 these.

Secondly, the Board in one of its orders in the early '90s chastised the two utilities for being tardy and letting a balance build up and not moving quickly, so the companies since then have said, Okay. And what Mr. Bowman is saying flows from that. Don't let the balance build up. Don't get -- don't be tardy in dealing with it.

Q So there isn't any set balance before you actually make the, adjustment whether it's up or down, so collection or refund? So there's no upper and lower limits?

A MR. OSLER: That is correct.

A MR. MOLLARD: As a matter of practice, we try to keep, I believe, a balance of plus or minus 200,000 in the account.

A MR. OSLER: But that's a practice, not a --

A MR. MOLLARD: That is practice. That is not an approved policy in any respect.

Q That's what my next question was, if there was either an administrative or operational policy for Rider F, and I believe you just said there isn't --

A MR. MOLLARD: There is not.

Q -- this business practice?

Thank you.

Now, with respect to Rider J, in your next rate application, would you be applying to eliminate Rider J?

A MR. OSLER: Madam Chairman, we assume that the process that -- of discussion with YECL will include looking at rate matters that would allow the riders to be removed and normal, proper rates put in place.

If that -- if that discussion and that consultation process leads to a proposal to the Board and the Board accepts it, what you are talking about might happen before the next rate applications. You know, it would be a process following from what -- this discussion process.

But I can't -- the utility cannot -- YEC cannot predict beyond that. I mean it's -- it needs some overall discussion and framework in order to remove it, and it would require rate matters to be approached in order to remove it, and it probably should be considered as a joint discussion with the two utilities and not just

a matter for YEC to change on its own, in an ideal world anyway. So that's about as responsive as we can be, I think, at the moment.

Q **All right. Thank you.**

Now, this morning you provided the annual reports of the key performance measures, and I wondered if YEC has an internal key performance measures other than those that are set out in the annual report?

A MR. MORRISON: We have a recently -- we've had a couple of different attempts at this over the last few years. We are in the process of developing a KPI report that we are working through with our board. It's in the pretty early stages, I would say even draft. We gave the first one to our board as a draft at the last board meeting, which was a month ago.

I'm waiting for the next question which is can I give it to.

Q **Well, since you asked the question, can you answer it now.**

A MR. MORRISON: Since I asked the question. When's the other shoe going to drop.

We can -- I don't have a copy of it with me. My only caution is it's still kind of under development, but I guess we can look at trying to do that on a -- do you just want a copy of the one we have or is it something you want with -- on a regular basis? I guess that's my question.

Q Well, at this point --

A MR. MORRISON: We'll give you the one we have.

Q Yes.

THE CHAIR: You are going to give us everything. This is the time to ask. We just have our Board questions now.

A MR. MORRISON: So we'll get you a copy.

Q MS. BENTIVEGNA: Thank you.

Now, in your opening statement at page 7, you refer to the -- that YEC will meet with YECL regarding a Phase II application, and I wondered when YEC expects that a joint Phase II application might be filed?

A MR. MORRISON: Yikes. Well, I guess, you know, to be fair, we're going to have to sit down with YECL to see, you know, what

they've got, how long it's going to take us to put our information together. I'd hate to get out on a limb with an estimate that I can't stay to. So I'm just not exactly sure. We'll certainly do it as soon as we can. I can make that commitment.

A MR. OSLER: One of the things we have assumed is that I think it was -- in the statement is that the Board's order on our application would give the framework for both utilities to know what the revenue requirement is that the cost of service should be based on. So I assume that when the parties meet that they will probably endorse that idea and therefore the timing will be contingent to some extent on that.

In the past, utilities have said in the letters to the Board that they thought it would take three months when they had the information to prepare a cost of service. I don't know whether that's still feasible, but that's at least in a matter of record. And there's a lot of other matters that people think we should discuss in consultations. So I think the utilities will

have to meet and discuss that and, you know, maybe inform the Board of what they think -- what the game plan is, what they propose as a work plan. And I think that was implied in the letter if not in the opening statement and then inform the board and other parties how they propose to proceed. And if there's any other directions anybody wants to give them, then they have time to give it to them.

Q All right. So from your experience you can't give us -- thinking that the last time there was a cost-of-service study was 1992, but you don't have any indication, any parameters at all as to what you are working for or aiming for?

A MR. OSLER: The last time we had a big cost-of-service hearing was '92, but the last time we did one together was the '96-'97 GRA, and we did them fairly expeditiously in those days. And we had been working together, you know, for nine or ten years, and we also had resolved the big policy issues in front of the Board in '92. So we were very focused in those days on the issue of the focal point was getting the cost of services required for the

major customer Faro mine so that when the contract ended in that mine there would be a basis for the Board to enforce or to approve a rate that at least met the cost-of-service requirement of the order in council.

I think the issues that both companies would face right now is that I guess I'm probably the only person around who was there at that time, so -- and I didn't do the computing work. So we have to sit down and go through all the issues, and it may take more time than would be normally the case. And I'm assuming that's why three months was the type of parameter that was put forward.

So the best we have is what you have in front of you at the moment, and we have to have some meetings and discussions that would allow us to give you something better.

Q Can you provide any indication -- again, in the opening statement it talks about that the discussions will have to include rate design changes and based on current relevant order in council directives and as well as planning for future rate designs once the order in council

expires in 2012.

Can you give us any indication of the type of rate design issues and options that YEC intends to bring to the table.

A MR. OSLER: At a high level, yes.

Q Yes.

A MR. OSLER: The one that we have been emphasizing in this application is the runout rate issues which this application does not purport to resolve for the general service class or resolve in terms of a long-term approach beyond in dealing with what's been -- the requirements in the past.

In dealing with the general service class, the fundamental issue is that most of the sales are in the second block. The Board has the -- in our application we have that type of information in tables, which have been provided in Tab 4. 4.9, Table 4.9, provides the volumes by class, and you can see in there what percentage of the general service class is in the second block. And I believe it's, you know, upwards of over 70 percent.

When you have that high a

percentage of sales in the second block, the ability to increase the runout rate and still not have the whole class have problems, you have to reduce something else if you are going to increase the runout rate.

If we were to increase the runout rate by the same number, 5.61 cents that we proposed for the residential class, there would be no first block rate. We'd have to reduce the demand rate or do something else. It's that big of a swing.

So we think that we will have to sit down and discuss more rate blocks for the general service class to make this work. That's not an easy issue to discuss quickly, but it's not surprising. We have seen it in other jurisdictions. So that's a big issue that we flagged in this application, and we would intend to be discussing it. It's not really cost of service related. It's very much rate design related.

The Rider J issues that UCG has asked us questions about, you know, how do we get rid of those riders and deal with them in the basic rates given the constraints

of the Order in Council 2008-149 where we have to keep each customer class with no difference in its overall revenues that are collected from it, that problem the utilities faced together in the early '90s when the same constraint was there.

It didn't stop us from second block rate changes and it didn't stop us from other developments at the time. But the issues today given the lag of ten years are much -- appear to be much bigger, and the gap between where the rates were at and the diesel costs are much bigger, so that's a big challenge.

Those are probably the two biggies from Yukon Energy's point of view, as well as trying to finds ways to do all of this without having to have three separate hearings in the future. I think we flagged that issue too because of the concern about regulatory costs and other things. So we were trying to see if we can get back to where we used to be where these things got handled from an overall public interest point of view more efficiently.

Q Great. Thank you.

A MR. OSLER: I can add one more thing for the transcript that we also will deal with wholesale rates, which Mr. Keough questioned us about. Just it slipped my mind as a topic, but I'm sure it will get discussed.

Q Now, there was a discussion that occurred with Mr. Maissan on the need for the Mayo B, the Atlin-Gladstone and other hydro projects. Can YEC undertake to provide a table indicating YEC's estimate of when the hydro project is required, project timelines, including regulatory process, estimates of cost of the project, the energy output of the project, and the expected external load driving the project. And that would be for each project that we would ask that each of those be indicated.

A MR. MORRISON: My answer generally is going to be no.

Q All right. Can you explain.

A MR. MORRISON: Well, it's the first time I've said no.

THE CHAIR: Are you saying it's not relevant?

A MR. MORRISON: No. I just -- all of

those things I can't do. We are -- we are not at a stage with those projects where I can provide all of that to you at this point in time. At some point in time I can provide all of that to you, and if the undertaking is to do it sometime at a date in the future, I'm happy to do that.

What we can tell you is we could certainly give you, you know, a basic outline of the project as we think it's there, but I think we may have done that.

As I mentioned earlier, we are just in the process of engaging some consultants for a number of those projects. We don't have project costs of -- you know, in any kind of a format that would be -- I would want to rely on. We technically understand, you know, what we're trying to do with the projects.

I don't have a timeline other than we can tell you when we need them. We can certainly undertake to do that in terms of our forecast when we need those gigawatt hours, and I would be happy to do that.

A MR. OSLER: The biggest problem we

have in answering you is that they are project specific. The discussions that had taken place so far aside from Mayo B or Carmacks-Stewart have been as a package of projects to deal with a specific set of requirements.

So we tried in the answers to questions to give you most of that information and we could consolidate it like we did with B-20 and maybe add a few bits more information that is readily available at the moment. I think Mr. Morrison commented on the requirements side. I think we can give you a clean simple description of the load requirements as we see them emerging in some of the risks over the period we are talking about to 2015. We could probably -- we have put on the record the timelines with Carmacks-Stewart and Mayo B so we can just reiterate what we have said to you. The other projects are the ones where we don't have project-specific time lines or things. We have endeavours to try and get them done as soon as possible.

We could probably -- I don't think there is anywhere in this transcript that says what the generic levelized

costs are that we have assumed for Gladstone or Atlin or things like that. We could probably tell you that which would help explain. They are in the resource plan initially, but I don't know if we updated them or just relying on the resource plan. We can pull that together so everybody doesn't have to go all over the place looking for it.

Q That would be useful.

As well can you indicate what the external load driving each project so that what would be the -- what would indicate to you so that you can plan the timing? What point is the load going to the need, the external load then and relate it to the particular project? So what will trigger all the different -- for example, the -- a mine load.

A MR. MORRISON: Yeah.

Q Would that then trigger one of these, so that type of information?

A MR. OSLER: I will give you this much on the transcript right now, because it's fairly simple. Mayo B project, Carmacks-Stewart project if the funding is

available are needed in the time period of what we're trying to deal with, 2011, fall of 2011, early 2012 without Carmacks Copper being committed, they will both be of value -- they will be of value to a system looking at the values emerging to 2012 with the Faro reclamation and things like that. With Carmacks Copper if it comes on the system in that type of time period or the next year it adds 40 gigawatt hours. So you can figure out from there why they say we need Gladstone, we need these other projects available.

It's a very major leap if you add Carmacks Copper to the picture. And that is something we are told we have to plan for. Beyond that, the load is growing at about, you know, 6, 7 gigawatt hours a year on the main system. So it ended up with us saying without any development at all before 2015, without any new resources being put in place at all on the Aishihik third turbine, we seem to need 50 to 100 gigawatt hours of load. So it's not so much the triggering of one project of the other project. You might say they are very valuable core projects, and where do we get the

rest, because people are worried that if we develop problems in the project we still end up with a fair amount of diesel. And that's why they are looking at geothermal, and that's why they are looking at other longer term projects to be able by -- as soon as possible be ready for those types of things.

But we're just looking at Alexco and Carmacks Copper as big triggers, and Alexco is already on the way to commitment. Carmacks Copper is such a big lump that it -- if it comes along, I don't think we can meet it in renewable resources at least in the initial years. We will be running diesels. Is that --

A MR. MORRISON: Yeah, I think that's fair.

This is the real trick in terms of our planning as I was talking about earlier is, you know, how do we get the right amount of surplus on the system or coming onto the system at the same time loads are coming on. And this system is so small, that's really difficult to do. It's really difficult to say, Okay, we have this. I can tell you today that I have exactly this much power coming onto the

system from new hydro, and here's my load exactly the same. It's virtually impossible.

So a year ago I would have said Western Copper's coming onto the system. We better get 40 more gigawatt hours of hydro on. You know, things change. You know, it's -- maybe it's a year later now. Maybe it's a year and a half later.

But trying to balance how we get, you know, new resources and new customers at the same time has been a real challenge over the last couple of year. And we'll do our best to map all this out for you, but it's not as easy as all -- it's not as easy as saying, Okay, we're going to do this and here's the timeline and here's how much it cost and here's the customer. This is not Alberta or BC or Quebec where they -- the years of planning time ahead of things and the system can absorb all of those costs to putting a new project on and the customer is growing into it. We don't have that luxury.

Q All right. Thank you.

MS. BENTIVEGNA: Thank you, panel. Those are my questions, Madam Chair.

THE CHAIR: Thank you, Ms. Bentivegna.

I will ask at this time if there are any further questions from the Board. There appear to be none.

Mr. Landry, any redirect?

MR. LANDRY: I do have a couple of questions in redirect, Madam Chair.

YEC PANEL FURTHER EXAMINED IN CHIEF BY MR. LANDRY:

Q I will go with the most recent one first, and it arises out of a question from Board counsel. And I guess I would put it to you, Mr. Mollard. There was a reference to a certain amount of expense I believe in 2008 relating to the YECL intervention. Do you recall that?

A MR. MOLLARD: Yes, I do.

Q I think it was approximately, if I have the number right, 94,000.

A MR. MOLLARD: That's correct.

Q Now, that 94,000, is that in the 2008 or 2009 forecast revenue requirement?

A MR. MOLLARD: It is not.

MR. LANDRY: The second item, Madam Chair, relates to a question yesterday arising out of Exhibit C1-9 which was the aid

to argument or aid to cross-examination Mr. Keough introduced and it is in reference to -- I don't have the specific transcript reference. I thought I was going to be able to get to the break and I could get that, but I think we could centre in on that.

Q **MR. LANDRY: It's to you, Mr. Osler. There was a discussion with Mr. Keough about the scenarios relating to Rate Schedule 42, and you had indicated a reference to an OIC that dealt with the issue of the requirement that the rates charged to YECL collect effectively all of the costs. I wonder if you can just for the record inform the Board what OIC that is and what reference you were making in that OIC.**

A MR. OSLER: Madam Chairman, I was referencing OIC 95-90, but the same thing was in some earlier OICs, but that's the current one. I am referencing Section 7 of that OIC which deals with the setting of wholesale rates and in effect says those rates must be -- Order in Council 95-90, Section 7, which is dealing with the Board fixing rates of Yukon Energy Corporation for the wholesale power customer in accordance with the following rate policies,

and it includes those rates must be sufficient to enable Yukon Energy Corporation to recover its costs that are not recovered from its other customers. There's two sections, but they're both -- that's what I was referring to.

Q Thank you.

MR. LANDRY: Madam Chair, those are the only redirect questions that I have.

THE CHAIR: Thank you, Mr. Landry.

We appear to have caught Mr. Morrison in a particularly generous mood this afternoon with his undertakings. What kind of time could we expect those by?

MR. LANDRY: The last one gave me a little bit of a hiccup. So I'm wondering whether or not we might say by next Friday.

THE CHAIR: Do we have a date for that? What would that be?

MR. LANDRY: May 15th, sorry. May 15th.

THE CHAIR: So May 15th, the undertaking is to be provided.

And I just want to remind parties that simultaneous argument, written argument will be due May 22nd and written reply

June the 5th. Are there any other matters any party wishes to bring forward to the hearing?

Mr. Maissan?

MR. MAISSAN: I have a question in regards to reply argument. I am going to be travelling around the time when that is due, and I am going to have to prepare any reply very shortly after final argument is due. Should I be doing the same time as I did last time when I had the same problem, forward it to the Board to be circulated on June the 5th?

THE CHAIR: Would the logistics of that work, Ms. Lemke? That would be around June the 5th. It appears to be a workable solution.

MR. MAISSAN: Thank you.

THE CHAIR: I would like to adjourn this hearing, then, and I look forward to receiving everybody's written argument. Thank you for the last two days.

(PROCEEDINGS ADJOURNED AT 6:09 P.M.)

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ERRATA

Page 248, Line 10: "attempts" should be "tends"

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