YUKON UTILITIES BOARD

YUKON ENERGY CORPORATION 20 YEAR RESOURCE PLAN

APPLICATION TO THE YUKON UTILITIES BOARD

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BEFORE BOARD MEMBERS:

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Brian Morris	Member
Richard Hancock	Member
Michael Phillips	Member

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Renee Marx

BOARD STAFF:

Pat Wickel &	
Dwayne Ward	Technical Consultants
Deana Lemke	Executive Secretary

APPEARANCES:

Yukon Energy Corporation	John Landry
	David Morrison
	Cam Osler
City of Whitehorse	Wayne Tuck
Utilities Consumers' Group	Michael Buonaguro
	Roger Rondeau
Yukon Conservation Society	J. P. Pinard

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

THE CHAIR: Good morning, everyone. Just with respect to a couple of preliminary matters, we will look to adjourn today around 4:00 p.m., and lunch from 12:00 to 1:30, mid-morning break around 10:30, and an afternoon break around 2:45.

On another matter, I am not really sure that there is any significance between the fact that this weather and the hearing have arrived at the same time, but in checking the Environment Canada forecast for the short term, it appears we don't have much to look forward to in terms of the weather, anyway.

On that matter, Ms. Marx, do you have any matters before the Board you would like to bring

forward?

MS. MARX: I do not, but I understand Mr. Landry has some -- YEC has some undertaking responses to file this morning.

THE CHAIR: Mr. Landry.

MR. LANDRY: Thank you, Madam Chair. We have three undertakings to file now, and I think the balance, which I think will be two more, we will be able to get by the end of the break, we hope, so that counsel will have them

before he finishes his cross.

The first one that we would like to respond to is the issue that arose, Madam Chair, regarding the contracting policies, you will recall, and that was an undertaking, just for the record, that is at transcript page 208. So Mr. Morrison will respond to that.

A MR. MORRISON: Thank you, Madam Chair. Just in response to a question about, could we table our contracting policies. I would just like to advise the Board this morning that in the 2005 Revenue Requirement Hearing, we tabled, in

response to McMahon-YEC-1-72, we tabled 13 of our policies at that time. Subsequent to that hearing, those 13 policies, and all of the remainder of our policies, contracting and purchasing policies, and guidelines, have all been on our website. So I have a hard copy here, if someone would like one, but they are all on the website, and they have been for over a year.

MR. LANDRY: Madam Chair, Ms. Dixon will provide counsel with a copy, a hard copy, of both of those documents that Mr. Morrison has referred to, and if anybody else wants hard copies, we can get them, but they are on the website.

THE CHAIR: Would you like to mark

those as exhibits still at this time?

MR. BUONAGURO: Sure, we can do that.

THE CHAIR: So marked.

MR. LANDRY: What would that number be?

MS. LEMKE: B-16.

THE CHAIR: B-17.

MR. LANDRY: Correction, B-17.

EXHIBIT NO. B-17:

CONTRACTING POLICIES.

MR. LANDRY: Madam Chair, the second undertaking related to the near-term non-industrial load forecast that was being discussed yesterday with counsel, and just for the record, the preamble started at page -- approximately page 165, and the actual question came at page 177, and it related to the 2.2 percent growth rate in that near-term non-industrial load forecast, and the reference is Exhibit B-2, page 24. Mr. Bowman will respond to that undertaking.

And Madam Chair, just for the record, this is called Yukon Energy, Undertaking Number 1, which we can give an exhibit to in a second, but we did the numbering relative to when the undertakings occurred on the transcript. Mr. Bowman?

A MR. BOWMAN: Thank you. The

Undertaking Number 1 was to look at the 2.2 percent number that is used in Exhibit B-2 at page 24, which was one component of coming to the long-term

average growth rate used in the Resource Plan. And at that time, the Yukon Energy used a three-year average recorded increase in consumption, and "consumption" meaning YECL's wholesale purchases on the WAF system for firm sales, not secondary sales.

What we have prepared in this exhibit is the numbers that were used in the Resource Plan to come to the 2.2 percent, and also more recent actuals that we have recorded since the time of the Resource Plan. At the time the Resource Plan was prepared, full year actuals were only available to the end of 2004, it was being prepared within 2005. So in the table that has been handed out, you will see that the numbers are listed on the left-hand side, and what we have done is put in bold and italics the numbers that were used in the Resource Plan for the 2001 to 2004 period, which is the three year period that was being addressed in those columns. Column A, that is listed there, is the WAF firm wholesales which is YECL's purchases from YEC on the WAF system, and these are in kilowatt hours.

In order to come to YECL's native load, which is the relevant number for considering the long-term system, one would add back the amount of generation YECL provides itself from Fish Lake, which is listed in column B. So that the third column there, which is listed as A plus B, is what we would call YECL's native load. I note that the table calls it a native peak; it is not a peak, in a sense of megawatts, it is an overall annual load also in kilowatt hours, and that is the load number that represents the total load on the distribution system on the WAF.

The following column shows the annual growth rates that were experienced during the period we are looking at, and you can see the reason for choosing the 2001 as the starting point is that, by the time the Faro mine closed in 1998, and the next couple of years, there was a substantial trickle down through the economy that some people here will appreciate more than myself, but that ended up being stabilized by about 2001 and, by that point, the load sort of resumed to normal type of patterns. So the bold italicized numbers there represent the three years that were looked at since 2001; one year of 1.3 percent, one year of 2.4 percent, and one year of 3 percent. And 3 percent

is cited in Exhibit B-2, as well, as the highest annual recorded increase in consumption to that point. The three year average of those two is 2.2 percent, which is the number that was used in the Resource Plan.

Since that time we have recorded 2005 actuals and 2006 actuals until the end of October, and those are included in here, as well as the 2006 forecasts for November and December that Yukon Energy is using. So that when we add in the full benefit of the loads we now know, we can see that the 2005, the impacts of a very warm November and December in that year, so that the growth was very modest, and 2006 now is showing the more normal weather pattern related to the ongoing growth. And the rolling three-year average is shown in the final column. So that if we use the updated information we have to date, the 2.2 would be more like 2.6 in terms of a three-year average.

What we set out in the final right-hand column, the undertaking requested us to use the same methodology as we used in the Resource Plan.

The methodology in the Resource Plan was to look at the period since the Faro mine stabilized, the longest period of record available which, at that time, was three years. If we continued that

methodology, saying we would look from 2001 until the best available recent data, that would be the number shown in the final column. So that the 2.2 percent, which was a three-year average, the following year, when we built in '05, it would drop to 1.9, and the year after that, when we build in '06, 10 months of actuals, it would be up to about 2.3. So it doesn't materially change the conclusion.

And just for the benefit of people who are fascinated in these type of details, below the line is -- because 2006, of course, we don't have actuals through the entire year, and we did not want to get confused about the extent to which forecasts for November and December might be skewing what is otherwise actual numbers, we have put, at the bottom, just the January to October period, so that one can compare actuals to

actuals. And it emphasizes the point that we are setting out above, that the growth that is now being seen, 7 gigawatt hours of the growth between '05 and '06 is already in hand, those are sales already made. And 10 gigawatt hours compared to 2004, or almost 10 gigawatt hours compared to 2004, those are sales that have already been made, and they do not rely on any type of forecast. So it's

not that the 2006 forecast number up here is hinging on any particular weather pattern, or loads, in November or December.

Q So could we have an exhibit number, B-18 is that the correct --

THE CHAIR: So marked.

EXHIBIT NO. B-18:

YUKON ENERGY'S UNDERTAKING #1.

MR. LANDRY: And the final one for first thing this morning is an undertaking relating to YECL's purchase power forecast for the past three years, you will recall, Madam Chair, and the preamble starts at page, I believe, 175, or

thereabouts, and the actual question is at page 179 of the transcript, and Mr. Bowman, I think, is going to answer that one, too.

A MR. BOWMAN: The table that has been distributed, the package of materials, five pages, is the information that was requested in regards to the data that YECL provides to YEC on an annual basis. The reference was to a letter that YECL provided to YEC setting out the data that they provide, and it referenced that, in each year, it provides a forecast of the current year plus the following three years, and we were asked to provide the last three packages. Because we did not have

the transcript, we were not perfectly clear if the last three packages was '03, '04, '05, or also to include '06, so we put all four in just to make sure that we have covered the bases. '06, of course, though, we don't have an actual year to test against at this point.

The front page summarizes the data that is in the following attachments. The back four pages, I won't bother to go through, but in each case, it

will set out a fair bit of detail for YECL's forecast for the current year, and then at the bottom of the page, the number of future years they give, and it is not always three, some cases it is four, and some cases it is two. But this is the level of data that YECL provides YEC.

I will just note that the tables that are attached are substantively the format provided by YECL, and we are assured by the people who deal with YECL on these that they represent all of the numbers provided, but in some cases, they have additional notes added by YEC staff who are dealing with these tables. They are just an Excel file.

In order to make it simple, we have summarized it at the front, and on the front page, if I can just take a minute to go through, this sheet is in megawatt hours, and the numbers provided by YECL,

in particular in regards to future years, do not break out WAF versus Mayo-Dawson sales, so the numbers we are dealing with here are total wholesales and include WAF and Mayo-Dawson. Now,

Mayo-Dawson is a very small part of these. In the first couple of years up to about 2005, it is about 250 megawatt hours, so less than .1 percent, or about .1 percent of what is shown here. Starting in 2005, Stewart Crossing was connected, so it goes up to about 750 megawatt hours of these numbers. It is a very small part, but I wanted to make sure we had that note. And again, these are firm sales, not including secondary.

What this table shows on the left-hand side, it sets out the year in question, and the actual sales recorded, and again for 2006 it is if full year forecast. For each of the additional columns is the forecast provided by YECL in the respective year. So the column entitled 2003 is the forecast provided by YECL in 2003, and at that time, they provided a forecast of 223 megawatt hours, increasing slightly through the following three years. 2004, you can see they provided an additional year of data, and 2005, they provided an additional year, and 2006, we have one less year than the normal three.

And just to follow across then, the concern that had been raised at times in regards to these forecasts, if you look at 2006, for example, actual sales this year, the forecast for November/December, are headed for 247 gigawatt hours. As of 2003, YECL was forecasting 2006 to be about 225. By 2004, they had raised that forecast to about 227, and by 2005 they were expecting 236, and this year's forecast was for 241.

So the extent to which this reflects different underlying factors, be it the big box stores, or changes in uses of electric heat, would all be on the other side of the meter, so it is not something that we can comment on in terms of general service versus residential. But the type of growth that has been seen here, again, I am told it won't be a surprise to anyone who lives in Whitehorse in terms of housing construction, and a number of other things that are being seen in this market, and the extent to which the growth is arising, even though it is not being forecast in the numbers that are being provided by YECL.

I would just make a final comment that the undertaking reference, the section in the letter from YECL that said they provided wholesale forecasts and actual and forecast Fish Lake, which

we were asked for as well ... I provided the actual Fish Lake data in the previous exhibit. That is data that YEC has gone to the Water Board to get. Going through the information available, YEC is not routinely provided Fish Lake actuals or forecasts. On occasion, it asks for them and isn't provided them, on occasion it is provided, but it is not a consistent part of the information provided.

MR. LANDRY: Madam Chair, can we have an exhibit number for that, please.

THE CHAIR: B-19, so marked.

EXHIBIT NO. B-19:

YUKON ENERGY'S UNDERTAKING #2.

MR. LANDRY: I would only reference, Madam Chair, for the record, the letter that was mentioned yesterday from YECL-C1-5 where there are some comments, I guess is the best way to call them, because I cannot think of any other way to describe them, by YECL in their letter of withdrawal, relating to forecast.

Those are all of the undertaking responses that we have at this point. There are two more, as we understand them, and we are hopeful to have them after the break this morning.

THE CHAIR: Thank you, Mr. Landry.

Mr. Buonaguro, are you prepared to proceed?

MR. BUONAGURO: Yes, thank you.

YEC PANEL FURTHER CROSS-EXAMINED BY MR. BUONAGURO:

Q MR. BUONAGURO: And thank you for getting back to us so quickly. I am moving on to the specific four project proposals that are part of the Plan, and I do not expect to be too, too long, actually.

With respect to the Aishihik Third Turbine Project, I really only have one question. We understand from the evidence that the project was approved for environmental -- it had its environmental licensing approved as of 1992, and it is all ready to go. Is that correct?

A MR. MORRISON: Hector can give you the details, but it is a water licence.

Q Okay.

A MR. CAMPBELL: Yes, the 1992 date was likely the date that we started the application to bring forward -- or to renew the water licence with

some amendments, and in fact, the process was completed -- let me just get it out -- in 2002, and it was a 17-year licence, but that licence does include the approval to construct the third turbine for up to 7 megawatts capacity.

Q I think I understand. So you are saying that, from 2002, you have 17 years to build it under the

current approval?

A No, the current renewal period of the licence is for 17 years.

Q Starting?

A 2002.

Q Starting 2002. Is the licence current -- my only concern is whether or not there's changes in the licencing criteria since the time it has been licenced. So you started the process back in the 1990s, licensed in 2002, presumably with respect to meeting whatever criteria you had to meet as of 2002. I actually don't know if things have changed since 2002. Do you know, is it grandfathered to whatever the existing was in 2002, and if there is changes between then and now; or when you actually

do the project, are you obligated to update what you do to meet changing conditions?

A No. The water licence that was renewed in 2002 was under the CEAA legislation, which, in the Yukon, has now been replaced by the YESAB process, and in fact, that is the process the utility would likely have to pursue in 2019 upon the subsequent renewal of that licence. But, no, there is no requirement to -- just because there has been new legislation put in place, the terms of the water licence are current, then.

Q All right, thank you.

Moving on to the Marsh Lake project, you answered some questions about this, but I just want to be clear. As I understand the update and your earlier evidence, the reason it has been taken off of the table, so to speak, is because consultatives resulted in a lot of opposition, and that opposition meant that the process of obtaining the proper approvals would be prolonged; is that a fair assessment?

A MR. MORRISON: That is correct.

Q But I also understand, and there is no mention of any specific evidence brought forward by any specific consultative group, that actually shows that you would fail at the licensing, it is just the drawn-out nature of the licensing that takes -- it is not an increased possibility that you are going to lose because there is some factual reason why it should not be approved.

A The Marsh Lake project, through the consultation process, is very evident to us that nobody was going to be going through any regulatory processes in any great hurry, and there are two very significant processes, the Water Board, and the YESAB process.

One of the advantages to Marsh Lake, if it was

possible, was that it could be done -- that it needed to be done fairly quickly. The YESAB process can be a process that you can go through, you know, fairly efficiently, or it could take two and three years to go through. And we have been through lengthy regulatory processes, at the Water

Board level, particularly, that have cost millions of dollars, and we are not prepared to address that issue, at the moment, for a 1.6 megawatt project.

Q So you are actually projecting that -- the original proposal, I believe, said that you anticipate the licensing process would be no more than $1 million. Are you projecting the actual cost of licensing being significantly higher than that?

A Well, we are not projecting it at all, because we are not doing it.

Q I understood, though, you seemed to be suggesting that, now that you know that there is going to be a lot of opposition, that that would somehow go higher?

A That was one of our concerns.

Q Can you identify how much money was spent on the process for Marsh Lake up to date, up to the point that you terminated it?

A Well, we went out there and had two public meetings at Marsh Lake, we had a public meeting at Carcross,

and we had a public meeting at Tagish.

Q I think that is another way of saying "negligible"?
A Yes. And, you know, coffee and doughnuts. And there is an IR filed on this information anyway, but we will get you a reference, if you would like, but it is negligible.
Q And do you not see any value in having the project available in the next 20 years, much like I understand the Aishihik Turbine Project has been available since 2002?
A No, Mr. Buonaguro, I do not see any value in going through a process, at this time, that we don't think we have a lot of -- the chance of success with. We have a lot of other work to do, and this would take a great deal of our time, if we are going through a lengthy regulatory process, and I do not think it is worthwhile doing at this time.
Q You mentioned chance of success, and as I understood it, there wasn't actually anything new in the information about the prospect of getting it actually licensed, it was rather the time involved.
A Well -- sorry.
Q So are you saying that the actual chance of success has actually been impacted, the actual factual elements have changed, or is it simply --

A No.
Q -- the fact that it is drawn out?
A It is drawn out.
Q Okay. Exhibit B-3, which is the supplemental material to the Resource Plan, at Tab 3, page S3-2, this -- at S3-1.2, right at the top of the page, it refers to a study to update specific knowledge of the hydrology of the Southern Lakes region. And as I understand it, there is a larger study, and from what I am reading here, the Marsh Lake Fall/Winter Storage was an aspect of that study. Am I correct in my understanding?
A Well, you could look at it -- the projects are inter-linked to a certain extent. If we were proceeding with Marsh Lake Fall and Winter Storage, the hydrology study would incorporate some aspects of the work that needed to be done regarding the Marsh Lake project. There is still, in the Southern Lakes, a watershed, there are still some areas that we think are worthwhile doing some hydrological work on for future benefits and future projects. The difficulty, of course, will be, now, those projects and that hydrology will have to be related to projects that do not require flow or storage in the Marsh Lake area.

26 Q So you are actually taking -- you are still doing

1 the study, I understand it?
2 A We will do a limited -- not the same version of
3 hydrology that we would have contemplated by doing
4 the Marsh Lake storage, as I said, if it was
5 included. But there are some potential prospects
6 in the Southern Lakes watershed, in addition to
7 Marsh Lake, that we will look at.
8 Q Now, my instinct tells me that if you are doing a
9 hydrology study anyway, it may be useful and cost
10 efficient to include scenarios that include the
11 Marsh Lake storage even though you are not
12 proceeding with it now. Do you have a sense of
13 difference in cost if you were to include --
14 continued to include --
15 A No, Mr. Buonaguro, I do not. And your
16 instinct might tell you that. My instinct tells me
17 that I do not think we should be wasting money
18 doing a study on an area that we are not going to
19 advance at this point in time.
20 Q So your answer is, you don't know what the cost
21 would be?

A I don't know the difference in the cost, no.
Q Thank you. Turning now to the Mirrlees updates, or Life Extension Project. In the original Resource Plan, and you do not have to turn this reference up, but it is at B-3, Tab 1, S1-2, there is a short

reference which says that NTPC recommends that YEC not retain the units. Then, if you go to page 44 -- sorry, let me get the exact reference here. It is UCG-2-42, Attachment Number 1. It is a very long report from NTPC, page 44. It is the recommendations from NTPC, a summary of the recommendations. Do you have that?

I can read it to you.

A MR. MORRISON: Perhaps you can just give us the reference again.
Q It is UCG to YEC-2-42, Attachment 1.
A MR. CAMPBELL: What page number?
Q 44 of 95. All right?

And the second paragraph from the bottom, it begins to explain the recommendation, and I will just read it for the record:

"It is strongly felt that it would not be in the best interest of YEC or its customers to spend any more money on the existing Mirrlees units. The units have served their purpose and are now arguably at the end of their useful life. Despite assurances and promises from the OEM (OEM agent) that the units can be economically rebuilt and continue in service, it would not be money well spent. Regardless of

the questions surrounding whether, in fact, the units can be rebuilt, it is still 40-year-old technology. The units are not fuel efficient relative to modern diesel units especially when operating on like fuel. The units have an earned reputation of leaking fuel, oil and coolant resulting in a continuous environmental concern/liability. These units require constant attention and maintenance. This is not likely to change significantly after the rebuilt.

If these units are rebuilt, YEC will have spent upwards of 8.2 million and not significantly improved its present-day position, nor be in any better position to meet future load growth within the WAF system."

I think you touched on your response to this recommendation in your evidence, but it would be useful to us to have a more fuller explanation on the record why this recommendation doesn't apply, or why you think it doesn't apply to YEC.

A MR. MORRISON: Thank you. Madam Chair, this issue and this subject have been probably one of the most difficult decisions that I

think our management team and our advisors have been through in the last little while.

I think, first off, one major difference between, I think, what the NTPC staff were telling us in their recommendation here is, looking at these -- the difference between what they are talking about and what we are talking about is the

difference between using these engines as base load engines, and using them in a back-up capacity. And this difference has also, I think, been a difficult concept for us to get our heads around as well.

When we look at the capacity planning criteria, when we look at what we need on the system to meet the peak load in the winter, I do not see any way that we can do it without having that 11 megawatts of capacity on the system in a back-up situation. And I am going to be very, you know, rough in my estimates here, but 11 megawatts at $1.2 or $1.1 million a megawatt, to buy new, is upwards of $15 million. We looked at these three Mirrlees engines, and we did a great deal of due diligence in terms of whether or not we could get parts, whether or not we could have some certainty around continuing to get parts well into the future. We have documents, we have records from the original equipment manufacturer that gives us

those assurances, we have visited with them to ensure that we understood clearly how they were going to provide parts on an ongoing basis, and

service, from their technical expertise.

If we can refurbish these engines ... and what we are talking about doing is called a 12,000 hour overhaul, which means that the engines, after that, should have 12,000 hours of life in them. Well, if we run them 100 or 200 hours a year, in a back-up capacity, that is a lot of years of life, compared to spending $15 million for engines to do the exact same thing; sit there for years at a time, only running maybe 100 or 200 or 300 hours a year, in a back-up capacity.

So our difficult decision, and we hired -- you will see, in the B.C. Hydro Report that was mentioned earlier, that B.C. Hydro said that these engines should be retired unless you spend some money on them. So they have said, you should retire these engines, do not spend any money on them. We have another opinion that says there is nothing -- there is no reason that you cannot fix these engines.

We have taken the extraordinary step of taking one of these engines -- the manufacturer told us a further step, that would give us comfort, would be

to pull the cylinders and have a look at them, and that would tell us whether or not there was significant wear and damage. We have done that. We have done, I think, everything we think we can do to make sure that we know that, when we fix these engines, they are going to work, and they are going to work for a considerable period of time after they are fixed, not just a year or two years. We are looking at these as engines should be there for, you know, a 15-year period, you know, somewhere in that neighbourhood. Now, it depends on how much they get run.

The question is, is a difference between base load and back up, and right now these engines, through our Plan, are designated as a back-up facility, and I think that is the difference.

Q Thank you. Just one aspect of it, which I do not think was specifically addressed, was the statement that it is a continuous environmental concern or liability. Could you address that particular?

A No, I do not think the engines are a continuous environmental liability. They leak a little oil, they are -- that oil is collected in the plant, it doesn't go outside the plant. It is within the shop. I do not think we have an environmental liability with those engines, specifically.

Q Did somebody want to add to that?
A No.
Q I just have, actually, one more question on the Mirrlees?
A Sure.
Q And I think part of your answer has already been said, but I might as well ask the question. The report, that same report, talks about the fuel efficiency of new units as opposed to the old?
A Sure.
Q Can you comment on that? I do not know if you have the numbers, for example, of how -- I guess there would be projected fuel savings in addition to increased megawatts if you had new units?
A Yes. Two things, and I will let, you know, either Mr. Osler or Mr. Campbell jump in on this one, but again, the total cost -- there is no doubt that you can buy more fuel-efficient engines, but they would be new engines. And again, we are not running these engines as base load. So if we are going to run them only a few hundred hours a year, there is no fuel efficiency to be earned here. It is not

any significant number at all. And the difference between getting a fuel-efficient engine and not running it, and spending, you know, double the money on the capital side of things, there is no

payback there at all, by any stretch of the imagination.

Q Thank you. Moving, lastly, to the Carmacks-Stewart Line Proposal, which will probably be a little longer than the previous three. In reviewing the proposal, you talk about a $10 million interconnection benefit, for example, to the ratepayer, and a portion of that is approximately $5 million in displaced fuel savings, diesel fuel savings, projected out to 2025. It occurred to me, in looking at that, that there should be an accounting for operation and maintenance costs incurred as a result of the line as well, and that these would also be projected out into the future of the life of the transmission line, and I did not see that being accounted for in either the original proposal or in the update. Have you accounted for O & M costs related to the new line, and then

worked that into the cost/benefit analysis?

A MR. OSLER: I will let Mr. Bowman elaborate, if he thinks he has something to add. Generally, the answer is no, at this stage in the work. The types of estimates that we would be putting in there for the fuel savings would be pretty simple, and we have not got the basis for getting a comparable level of -- getting the level

of detail at this stage that you get into. And transmission costs, operating costs, as such, are very low in number, which start off at a very minimal level, and then climb as the years go on. At some stage, we would certainly have to get into that level of detail, but I believe in terms of this interconnection level of thinking, we have not done that at all yet.

Mr. Bowman, do you have anything to add?

A MR. BOWMAN: No.

Q So there is a number in there, you don't know what it is, but you think that it is low?

A MR. OSLER: It would be a very low

number. It would not materially affect what we are trying to deal with. The uncertainties, with respect to the number you are looking at, are in estimates based in the original B-1 report, based on the load assumptions, on the Mayo-Dawson and the WAF systems, that are noted in that report, as what surplus hydro would be available on the Mayo-Dawson system, assuming there is no new mines. And each year, that number goes down a little bit because of normal load growth. It would go down a whack if the United Keno Hill Mine came on. Hold that thought.

The second thing that is affecting the value

of the interconnection, for energy savings, is the load on the WAF system. In its simple language, you are going to save a lot more money if the connection occurs when you have the two mines on, as well as the load on the -- the non-industrial load on the WAF system. Our operating assumption back then was, you would not probably see the Carmacks-Stewart line without at least one of the mines, and I think our operating assumption today

is you would not see the full connection without both mines, just as a practicality.

So on that basis, the load on the WAF system would be high enough to have a need, a use, for that surplus on the Mayo-Dawson system, to displace diesel generation on the WAF system, and you would make the savings. If we get to the next level of refinement of this, there would be extra costs for the diesels operating, and everything else, on the WAF system, that we have not brought into account by just looking at a very simple calculation, largely based on fuel, and there would be an offset that would not be very material, in present value terms, for the operating costs of the Mayo-Dawson system. It would be a very small percentage, from our experience -- for the Carmacks-Stewart system, sorry. It would be a very small effect on the

overall calculation that we are talking about, and, in the realm of the uncertainties and issues I am dealing with, would be inconsequential at this stage, so it is just not worth getting into that

level of detail.

Q Related to that, in terms of the fact that the benefits are projected into the future, but the costs are borne up front and then, presumably, rolled into rates in one form or another, I did not see anywhere an annual breakdown of how the costs versus the benefits track in the years. So I would expect that the costs, to some point, would be very high in the beginning years, and then taper off, or the benefits would taper off -- well, I don't know exactly how it is going to work. But the costs and the benefits are described in the Plan as all happening at once, being reduced to present value, but in reality the costs and the benefits are experienced over the course of a number of years, and either fluctuate, go up or down, based on how they are treated either in rates, or in how the benefits are actually realized, and it would be very helpful to see how that tracks based on your analysis. Can you provide that information, how your current cost/benefit analysis tracks on an annual basis?

A MR. OSLER: The short answer is, we can provide you the assumptions that were used to calculate the present value of the energy savings in terms of a distribution of megawatt hours in different years. I would have to track down that number, wherever it is, but we could get you that, because there would have to be a number for it.

In Appendix C of the initial B-1 filing, there is a case, at the very end, that shows the annual numbers on the WAF system, with Marsh Lake, Aishihik Third Turbine and Carmacks-Stewart integration. So those set of numbers are out of date only because we don't have Marsh Lake as part of the Plan anymore, but they are sort of an indicator of the types of numbers we were using at the time we did the Plan.

If I could, I would make -- your question had a long preamble about, it would be nice to see, and we don't see it, and maybe it would look like this. I would not mind commenting on that, if you are interested.

Q I am afraid to invite you to comment, the way you prefaced that, but I guess it cannot do too much harm.

A I think we have seen, in the Aishihik Third Turbine or the Mayo-Dawson analysis that we've provided, a

standard set of tables that show cost by year, for the project in question, and savings by year, for not running diesel. And we have been able to do that because of the nature of those projects, and they have been instructive to the Corporation in assessing cost/benefit, in general, what we call economic analysis, and then we have run the analysis on a financial basis to show potential rate effects year by year.

This type of analysis is filed in this hearing, in Appendix C, for the Aishihik Third Turbine under a variety of cases. And you have the first table for each case is an economics table, and the second table for each case is what we call a rate impact table, and they completely parallel the information we gave the Board in the hearing last year, with respect to Mayo-Dawson. There are many projects where that type of analysis is useful and we're able to provide it.

In the case of the Mayo-Carmacks-Stewart project, at the stages we have been going through, we faced a different type of situation. The project intrinsically, when we started to look at it, is not something that was going to generate

enough savings to warrant its being developed. It would depend, we started off on the assumption, on

government funds, so it would have -- basically, if it was fully funded by the government, would have zero costs and would generate the benefits. Our job was to show what type of benefits this might generate. And it was clearly, without the mine loads, not something that the Corporation would undertake on its own. The benefits were clearly well below the costs.

As we have progressed, we have gotten into more and more analysis of what might the mines be able to do, how might we proceed with this project in a way that would manage risks, and so the focal point has become not so much how we can save money running diesel, but how we can capture money from the mines, either in terms of commitments up front or in terms of ratepayer benefits. It is a different style of analysis.

Again, it does lead to an annual set of numbers that we are using, but it is more for the

Stage 1 analysis of that project from Carmacks to Pelly Crossing, what it would yield in terms of annual benefits and present values, and we can certainly provide you with back-up on those.

The interconnection that is the Stage 2, going from Pelly to Stewart, is clearly something, at the moment, we still think would need a likelihood of

government funding. It would certainly need the Carmacks Copper mine in place for us to take it seriously, and it would continue to bear the risks I just mentioned, when we looked at it: "Where is the United Keno Hill Mine at?", would be an important question.

Frankly, that part of it is another type of analysis from the more clear analysis we are now developing for Stage 1, with the clarity of the Minto mine being developed, and the clarity of what we are trying to negotiate and finalize an arrangement with them for a PPA. That starts to get us back into, here is a stream of annual numbers of loads that these people would use, what they could save compared to their diesel cost, what

we could charge relative to our Rate 39 and fair share of costs for this line. It is a more complicated analysis, it is more difficult, it takes more time to think it through. It is still easy compared to what we might face in five years time if somebody came along with a brand new mine, and we had to worry about generation being developed at the same time we are doing transmission. So it is a good first step in trying to get our mind around things.

But the type of analysis we used for

Mayo-Dawson, or we used for Aishihik Third Turbine, is not necessarily something we can always just pull out of a hat for each project to come up with, I guess, is my short comment, and it doesn't necessarily follow the patterns that we used for Mayo-Dawson, where the cost of the project, yes, tend to go down over time, and the benefits go up, but they do it for quite different reasons, quite different manner.

Q Thank you for that. Two points for clarification,

you said early in your answer that, originally, the project depended on government funding, so that there would be zero costs to ratepayers. That doesn't mean that there would be zero costs to taxpayers; I just want to make that clarification. Is that a fair comment on that?

A Yes, I agree with that.

Q And the second point is that, I understand what you were saying in your answer, but you do have a specific scenario in your proposal which you are putting forward for review, and the review -- the proposal includes an assumption about the yearly consumption of the mines, which has been compressed up front into a single value, for each of the two mines. It includes an assumption with respect to the costs, which would be rolled into rates in a

very particular way, which would then have an effect over time. And you have a specific assumption with respect to ratepayer benefits, which are presented in a lump sum up front but actually are calculated on a yearly basis. And I would think that you can, for my benefit, so that I

can understand how that plays out over time, your proposal, which I know is based on assumptions -- how that plays out in terms of rates. So I am basically asking for that information in an undertaking.

A You expanded your request to the mines, and that is fine.

Q Actually, I think -- I was asking for the cost and benefits, and the benefits -- the example I used was the fuel savings, but one of the benefits that is presented to the Board, in terms of offsetting the cost, is the input from the mines, which is something which occurs over time. So, in fairness to me, I do not think I changed my answer, but I think you were focused on my example.

A Yes, that is fair. We can get you -- let me look at what we can quickly provide you. The key assumptions for the mine load levels are all in each stage of our reporting, including the update, so that somebody would know what level of load we

were assuming for at the mines, and what years we

were assuming, but if I can find a way that we can give you a table that lays it out simply so you can follow it. The only thing I am not as sure about, because I have not looked at for a long time, is the numbers from the original document, on the interconnection savings, and that is what I was focused on when I was responding to you earlier.

Q I think you are understanding what I am asking for, and I think we can maybe work out the details on the break, or something like that, if there needs to be clarification.

A Yes, I just need to see what I can get you quickly.

Q All right.

A Thank you.

Q Now, you mentioned, in one of your earlier answers, that there was originally a pre-condition to starting the project that the Yukon Government provide funding, correct me if I am wrong, I think it was in the order of 10 to $15 million, I think it was 10. I cannot remember the exact figure.

A If you look at the January B-1 exhibit, I think, technically, we always said we would need to make sure that ratepayers would never have a net adverse effect, and it would have to be made up from the

mines and government. But bottom line, when we started this exercise at the beginning, we thought, at that stage, that it would be basically government for not just 10 or 15 million, but for maybe 30 million, the whole thing.

Q All right.

A And by the time we got to the supplementary material in June, we made a submission to government where I think the number had gotten to 10 million from the government, 5 million for Stage 1 and 5 million for Stage 2, based on our new information about the mines. The update that we have just filed is setting out a game plan to do Stage 1 without any government funds, but with a YDC contribution of 5 million.

Q I think you have anticipated what was actually my question, which was an explanation as to why there is no need, at least for Stage 1, with respect to government funding. I think the updated proposal is silent with respect to Stage 2, or potential further need for government funding. Can you comment on that?

A Yes. Stage 2 has all of the risks, certain issues that I just laid out for you, so we are being very cautious about our ability to -- stating Yukon

Energy's ability to do Stage 2, given those

uncertainties. We can certainly envisage scenarios where it would be dependent on the 5 million type of number we were talking about earlier, from the government, for Stage 2.

On the other hand, if Carmacks Copper hooks up and everything is working fine, and United Keno Hill is not around, coming back on the system, maybe the world would get better, and we could look at Stage 2 more optimistically. So we are cautious in our statements, at the moment, about Stage 2, but we are certainly not standing up and saying Yukon Energy could do Stage 2, for sure, without government funding.

The President is sitting beside me, and he has to deal with the Board of Directors, I am just the consultant.

Q I hesitate to use the word "elimination", but the removal of the requirement for government funding in Stage 1, and the prospects for the need for government funding in Stage 2, both of them are entirely dependent upon what happens with the

mines, in terms of what their contributions are going to be, and how the risks of the costs are being borne or not borne by the mines. Is that sort of a fair summary of what you have just said?

A No. And I can explain if you like.

Q Yes, please.

A There are two different issues when you are dealing with the mines. One of them is having a security that we are going to capture the benefits that we estimate if the mines are around. So if I have a mine here for ten years and we sell them this much power, and we sell them at a rate the Board has approved, and we have worked out exactly how they would pay for their portion of the line, and all of those types of good things, the first question we anticipate being asked is, what happens if the mine doesn't last the ten years, only lasts five years? That is called a security question, as distinct from a estimated flow of benefits. Okay?

So we are very conscious that we have to address the security question with respect to the

mines, if we are going to talk about relying on their benefits for the purposes of financing these lines, and I can address that more if you like.

In terms of the flow of benefits, bringing on stream the Carmacks Copper mine, at almost 50 million kilowatt hours a year of extra load, produces material benefits, if you can believe the security that it will be around for 8 1/2 years, that add, overall, to the Carmacks-Stewart line's benefit, Stage 1, et cetera, materially. That is

the type of thing that gives us extra ability to talk about doing a Stage 2 without, overall, having an adverse rate impact on Yukoners.

The thing we are most worried about, at that stage, is whether or not the energy that we are assuming is there from Mayo-Dawson is really there, or whether there are some things happening up in Mayo-Dawson that have used that energy for some other purpose, such as United Keno Hill Mine. So that would be the biggest effect of the thing. No matter how we do it, we have to make sure, before we hook up either mine, we need to address the

security question in order to support the numbers we are using to do our analysis.

Q I am interjecting with an out-of-sequence question here. I mentioned before about having determined that you projected the displaced fuel savings, as a result of interconnection, out to 2025. That level of specificity is not in the record with respect to the Pelly Crossing $2.1 million savings. Can I assume it is the same, you have reduced -- the present-day savings for Pelly Crossing, for displaced diesel, is 2.1, I guess, net. Is that also as a projection out to 2025?

A There is a note in one of the supplementary filings, I believe, of the calculation and the

dates, and the discount rate, it takes it out to the year 2020, assuming that the WAF system is on diesel, by that time, under the base load situation. Again, we could refine that as time goes along, but it is a concept of saving diesel. If we are going to be on a system that doesn't have a surplus, we did not want to give it a credit.

Q Small point.

I want to confirm some of the specifics of the proposal. As we understand it, under all scenarios where you are connecting a mine, the mine is responsible for the full cost of the 35 kilovolt line between the mine and a certain point, the interconnection point, I guess. Is that true, do you want to qualify that?

A If we are dealing with the Minto mine, it is true. If we are dealing with the Carmacks Copper mine, they don't have a 35 kV line. So the concepts go like this: if we are dealing with the Carmacks-Stewart line, as we define it, it is the line that goes from Carmacks, through Pelly, up to Stewart. We then talk about spur lines. They are the lines that come off that Carmacks-Stewart line to go to a mine. Minto mine would have the Minto spur line of about, we used to say 30 or so kilometers, now it is about 27, I believe. That is

a 35 kV line, given the load of the Minto mine. And Carmacks Copper would be about an 11 kilometer spur, it would be 138 kV, given the magnitude of

their load, and they would be totally responsible for it, on the principle that they are the only customer using the line.

So bottom line, any mine connecting to the system, including these two mines, on a line that is solely for their use, would be totally responsible for all actual costs of the line construction, and decommission.

Q Then, from going beyond that spur point and then connecting it to the actual grid, which is part of the Carmacks Transmission Proposal, I understand that -- I think there are some estimates in the original proposal for what the contributions would be from the mines, and how it would work. I understand, in the update, you have removed that in order to present the proposal without reference to particular contribution, in view of the PPAs are still being negotiated. I think that is one way of characterizing it.

What is the proposal? Is it the proposal to have the mines contribute an amount to the rest of the connection that is in line with what they would have had to spend if it was just them, or is there

some other proposal being worked on?

A Your characterization of the change in the update from earlier is fair, for the reasons you gave. So my answer is constrained, for the reasons of the update, in the sense of a negotiation process.

In discussions with either mine, as we laid out in our June submission, and in the answers to earlier questions, we have certainly made the point, if you had to be totally responsible for building the line you need from Carmacks, would it make sense, relative to the cost that you would incur running diesel, since both of these mines are seeking licences or have licences, in one case they are actually proceeding to be built and will start operating on diesel? In the other case, Carmacks Copper, they are seeking a licence, all of their applications before any regulatory body assume the mine will be run on diesel. Whether that makes sense or not, I am not going to comment, but that is their formal applications. In the case of Minto, it makes abundant sense, that is how they got their $85 million worth of financing. The market is great, and even if the costs of diesel fuel are high, they can make it work.

So in each case, we have looked at the economics, from their point of view, of providing

them with a 138 kV line from Carmacks, or a 35 kV line from Carmacks, and would it make sense? Would it pay for them to do that? And the answer in each case has been resoundingly yes, and, for the bigger mine, very much so. Okay?

That doesn't mean the mine is automatically desirous to pay what they would need in order to meet my scenario. They might do it if we were not building a Carmacks-Stewart line, they might not, depending on their frame of mind. Mines have a lot of other things to think about than worrying about electrical infrastructure. If they don't need it, they don't need it. If they can save some money, it is nice, but it doesn't mean it is their first priority.

We have, in general, had a proposition that has said, if we are developing the Carmacks-Stewart line, we would structure an approach that would be better for the mine than if they had to build the whole thing themselves for their own level of service, but would still be a positive contribution, present value worth, to the

construction of the Carmacks-Stewart line segment that they are using. How that can be translated into a PPA is the subject of active negotiation. We had an LOI that translated it in one manner, but

LOIs are, as you know, agreements to agree, and they are not the final agreement.

Q So I think the answer is something like, we will wait for the PPAs to come out, if they do?

A Well, the answer is it probably would not be -- our proposal, and the principles underlying the LOI, were that we were quite happy to have them -- if we built the Carmacks-Stewart line, 138 kV line, to Pelly, we were quite happy to have the Minto mine not pay for the full cost of the 35 kV line, ultimately net cost, from Carmacks to Minto Landing, but we absolutely need them to pay a reasonable portion of that cost for certain net of all provisions in the PPA. That is the subject of negotiation. It won't be zero and it won't be 100 percent of the 35 kV line.

You have a 138 kV line going from Carmacks to Minto Landing, then on to Pelly; 69 kilometres, I

believe, from Carmacks to Minto Landing.

We certainly have advised them of the cost of doing a 35 kV line for that distance, and have talked about that, if we were not around doing a 138 kV line, that is what they would have to build, et cetera, et cetera. But our ultimate proposition, from Day 1, has always been, if we are building the 138 kV line, we want you to pay a

reasonable portion of the costs, but it won't be as high as it would have been if we weren't building that line, but it is going to be materially greater than close to zero. And we are looking for security for that, forms of arrangement, either you give us the money up front, or you give us the type of security that we can rely on that commitment as a security for the financing of this line. And, essentially, the propositions that we have worked from conceptually are, if you are around for seven years, and you are committing to pay this much for this line, you will be buying power, probably, from us, from our grid, and providing these other

ratepayer benefits that we are just talking about, so we can rely on, concurrently, not only you are covering this downside cost issue, but you are, essentially, to the best of our ability, giving us security on the benefits as well.

Q In the original proposal, and I may muddle this, so you can help me out, the upfront payment that was being sought, at least part of it that was being sought, from the mines, was actually a prepayment of their energy costs, and they would get rebates. Is that no longer a scenario. Because I did not see it mentioned in the update, or is it still in play, so that this capital contribution we're

talking about is really a prepayment of energy, and they will get all that money back?

A Let me explain the original concept and say that, in my mind, it is potentially still a concept, but there are other concepts being talked about. The Minto mine's feasibility study, released in July, reflects a cost saving that they think they could get from having the grid connection, compared to diesel. They say it is about $4 million a year,

and, at present value, it is 7 1/2 percent of $19 million. We have reported on that in the update, and we have laid out some of the numbers.

As far as I can assess, that piece of work properly reflected the letter of intent, so the principles that I am going to talk about are reflected in that estimate. Essentially, that concept was, you will provide us with an amount of money, call it a capital contribution, call it a prepayment, we have used different language at different times, equal to the cost of a 35 kV line for this segment we are talking about, Carmacks to Minto Landing, and we will provide you -- if it is a prepayment, we will apply it to your bill, up to a limit for each year, and the limit we set was 20 percent. Under that structure, if they are around a long time, they recover that amount of money. If

they are around for a short time, they recover less.

Each year that they are getting this so-called rebate, or the prepayment is being applied to their

bill, we are, for sure, getting the balance of the bill in terms of the benefits ... the ratepayer. So we thought at the time, and we still think, it is a reasonable approach to giving us the security we like up front for a certain portion of the cost, but trading that off in terms of long-term benefits to ratepayers, and giving them, in the end, a better deal than if we had had to build the 35 kV line for them, that type of saving.

So that concept is reflected in their own cost saving estimates. We have updated those estimates to reflect the updated numbers. I did not give these in the update, but the present value savings that they would get using their methodology that they use there, given the update numbers we are using, the assumptions, would not be 19 million, because the costs have gone up, it would be more like 15 million. It is still a big number. I am not sure that that particular approach is the simplest way we can do it.

One of the practical problems that we could deal with, in dealing with that approach, was, we

were prepared to loan them the amount of money that is involved in their commitment, given adequate security. This is not uncommon in dealing with these types of situations. But we have had some discussions about the level of adequate security, I think we are getting much closer on that subject. But there are different situations in North America, and different situations here. With their securing their financing the way they have, and the type of time periods that are being reported for paying off their bank financing, the security issue seems to be much clearer and simpler today than it might have looked a while ago.

Q So if I was to summarize the answer to my question, maybe it might still be in play, but it might not, depending on how you actually end up negotiating?

A That would be very fair.

Q Okay. In negotiating the purchase power agreements, are the agreements based on a single scenario, or is the negotiation based on a single scenario, or are the negotiations contemplating, I guess, in a worst case scenario -- well, are you contemplating a range of scenarios in terms of full interconnection versus single connections just of the mines? Are there contingencies in the negotiations, so that you will actually have

multiple agreements, depending on what you ultimately are allowed to do before the Board, when the Board or the Minister reviews the proposal?

A As I would envisage the PPAs at the moment, they would be a document, not a set of alternatives, or a multiple set of scenarios. Certainly a multiple set of scenarios is part of a process of thinking it through, and trying to make sure you have covered off various situations, but I would not, at the moment, anticipate that the document would be that type of document. One of the biggest single problems here is timing. The two different mines give us two different examples of the practical problems we face in the future trying to deal with these types of situations, and frankly, we are lucky that we have got this set of situations as a training game.

The Minto mine is going ahead come -- going ahead, period. And it is, thank goodness, going ahead on diesel. And if we can get there soon enough to make sense economically, before they have stopped using -- before they got too far into it to pay off the thing over a reasonable period of time, it is a pretty straightforward situation. But we

have to get there by the end of 2008, type of time period, or it starts to be just silly.

So, if we are going to get there by third-quarter of 2008, as a target, we have to start construction in the summer/fall of 2007. There is not a lot of time for dealing with multiple document scenarios, people are looking for certainty. And for example, one of the pressures that mines come back at us with is, give me one rate. You talked about that with me yesterday, I think, let's keep it really simple; just tell me the rate.

There are a bunch of reasons we don't particularly want to do that. From their point of view, it makes complete sense; it is clear, we know what it is, and we can go forward together to the Board and get a rate. So we will discuss that, as to which is the most prudent and intelligent way to get a decision, quickly, that you like.

In the Carmacks Copper case, if they were to start operations, they want to start, they tell us,

without the diesel. They probably have 8 to $10 million worth of diesel plant that they would have to build if they are going to go on diesel. By starting with us, without that, they would not have to build that plant, unlike Minto, and so we would have to be there, though, on time for when they start. The third-quarter, is all they tell us,

2008. They have not got their licences yet. They, like us, are busy trying to get their licences. If they got their licences on time, they've filed for them, they would start construction at the same time we would like to.

Well, let me just say, so far, we have not got to the point of an LOI, and we are not doing any work on that project. And if we don't do the work on that project, and do not file applications to get the spur line done, it isn't going to be available on time. Now, I don't know -- I will just leave it at that. But these are not things that we can afford to go at, like the Aishihik re-licensing, for a decade. They have very defined time periods, either hit the window or it is,

quote, your document yesterday, they are called lost opportunities. Bye bye.

Q There was some discussion yesterday, with YCS, with respect to the buying back diesel power from the Minto mine's back-up as a part of it --

A Can you give us the reference, by chance?

Q Sorry, the reference in the transcript?

A Yes.

Q I just got the transcript this morning, and I only mean that as a preface. The question, I think, will explain itself. I think the reference from

the material was that, once they are connected, you might have the opportunity to buy back energy from them. And I think your answer yesterday, if I remember correctly, was that once they leave, there will be this diesel generator there that you might be able to buy, depending on the circumstances, as a back-up.

A MR. MORRISON: Not quite, Mr. Buonaguro.

Q I just want a clarification on what the actual

proposal or proposals are.

A I believe -- that was certainly the question, and I believe my answer was that we were talking about that the plant, that they would put in at their start-up, they would become redundant to them, right, excepting for the back-up that they would require to keep. But they have got some six-plus megawatts of capacity that they are putting in that would become redundant when they became connected to the grid. We have talked to them about, perhaps, purchasing that plant from them if we had -- if it would help us in a capacity situation somewhere. I also believe, and Mr. Osler can jump in, but I want to be very clear, we did not talk yesterday about buying energy from them.

A MR. OSLER: In YUB-YEC-2-10, page

3, we do talk about the Minto diesel plant, and I will just quote:

"The mine at Minto will be installing a prime power diesel plant to provide its needs during the period prior to the interconnection with YEC's system. Once

grid power is available to the mine, about 6.4 megawatt of diesel generation will become surplus to Minto's requirements, and is currently expected to be sold and removed unless YEC makes alternate arrangements with the mine. The feasibility of YEC securing access to these units for at least the near-term as a contingency option is being examined as part of the PPA negotiations for the Minto mine."

Those are really, I believe, four 1.6 megawatt units on trailers, so they are quite mobile. They are not all of the units in the plant, there is a bit more that they would retain for the emergency support, just for the record. The type of arrangements we have talked about would be us acquiring them, so it would be our units. We could do with them what we wanted, we can move them away from the site any time we wanted, we could sell

them, et cetera, so it would be part of YEC's

system, nothing to do with them providing anything.

The rationale as to why we might look at it is, is there some way, if they are cheap enough in the, sort of, Mirrlees category of costs, and resaleable, when we know exactly how the world is unfolding, that they would be an intelligent -- I would hate like heck to see us -- have them move them out, and then the next six months later say, you know, there would be something -- some value to the system. But, at the same time, I can assure you that nobody at YEC, that I am talking to is, lusting after those four 1.6 megawatt -- what do they call them, high speed fittings? So they are not -- only under the right set of terms and conditions would we even get past having a casual chat about it.

Q I think that is helpful to a lot of us, in terms of understanding what the actual proposal was. The only clarification, I think you actually said -- you would actually contemplate buying them while the mine is still there, not waiting until they are leaving?

A That is correct.

Q There is an actual possibility that it might be

done and then moved, or not moved, or something like that?

A Right. And it would be our units, and obviously the terms and conditions of us actually paying them would take into account how much they owed us under various arrangements, and would be part and parcel of the package, if we ever did it.

Q I have one more question for sure, and then after that question, I thought we might take the break, and then I can confer with my clients, see if we have any stray questions to finish up, I think we are almost done.

This is -- I actually ran into one of your engineers at breakfast, but I refrained from asking this engineering question because I did not want to put him in a compromising position. I think it is ultimately just for clarification for us. We understand that the Mayo-Dawson transmission line is 69 kilovolts?

A MR. CAMPBELL: That is correct.

Q And in terms of interconnecting the two grids, we couldn't understand, being non-engineers, whether that had to be upgraded to 138; if so, is that contemplated in the plan? Maybe you can explain that. Is it something that is a non-issue? I

don't know. I just wanted some clarification.

A MR. OSLER: Let me give you a non-engineer's point, just so that we get some certain things out, then I will let Hector handle the engineering points.

You take the two grids, so obviously you are going to take the voltage from one of them, so we are not doing 35 kV -- you know, 35 kV to Pelly Crossing would just contribute nothing to the long-term infrastructure ability to do the connection, as long as everybody in the room understands that. We had advice from Stantec, back a few years ago, that the cost of whether we did 69 or 138 basically did not make much difference, for a variety of reasons that I cannot elaborate on, but that was the essence of the conclusion, and other people have supported that.

The actual proposal assumes that you do not upgrade the Mayo-Dawson system, it still stays at 69 kV, and that the substation at Stewart is upgraded to accommodate the transformations necessary to go from the 138 kV to the 69.

Internal to the company, in the long run, it may make sense to look at strengthening the system from Stewart to Mayo, if the power development at Mayo proceeded, in the future, to more generation there for the whole system. You might strengthen that

leg, but you never would strengthen, I am advised, the leg between Stewart and Dawson. Now, that is the non-engineer's version.

Q Any engineering comments?

A MR. CAMPBELL: Actually, surprisingly, what Mr. Osler said was quite correct, even from an engineering perspective. The fact that the Mayo-Dawson line was designed, primarily from a capacity carrying capability, at 69,000 volts. And the rationale, with going to 138,000 volt, for the Carmacks-Stewart phase, again is based on a combination of factors. One of the significant changes in construction costs that has occurred, from around the year 2000 to today, is that the incremental cost, to build 69,000 volt versus 138,000 volt, has basically disappeared. So much

of the cost now is labour based, and it costs you the same.

So we are looking at 138,000 volts, both as a means of having a higher capacity on the line, and the fact that there is not a lot of interconnections along the way. The other factor you look at, from a voltage perspective, is it costs you more to step down from a higher transmission voltage to a customer. And we knew, when we were building the Mayo-Dawson line, there

was a number of lodges that wanted to connect, and it is cheaper to connect the lodge, or a residence or a small community, at 69,000 volts, than it is 138,000 volts. At the moment, the only known small community with connections on the Carmacks-Stewart line will, of course, be Pelly Crossing, and because we would be stepping down at Minto Landing, for the Minto spur line, there is the ability to provide relatively low cost to connect residential customers in the Minto Landing area, for example.

Q All right. One last little question on that, and I think you have mentioned upgrading the Stewart

station, and I would assume the cost of that is as part of the proposal?

A MR. OSLER: Yes.

Q Thought so. Just wanted to make sure. All right. I think those are my questions, but like I said, if it would please the Board, we wouldn't mind taking the 15-minute break to mull over any straggling questions that we might have, but I think we are basically done.

THE CHAIR: Thank you very much. Based on that, we will reconvene about 20 to the hour.

(Proceedings adjourned at 10:25 a.m.)

(Proceedings resumed at 10:50 a.m.)

THE CHAIR: Mr. Landry, you look like you want to say something?

MR. LANDRY: As I indicated, I wanted to complete the undertakings at least until the most recent one.

So the first undertaking I would like to deal with, Madam Chair, is what I am calling Undertaking

Number 3, which dealt with the issue of peak demand, request on the 2000 peak demand and 2000 peak to date. And Mr. Campbell will give that, and we do have a handout, and I will get you a page reference to that. I just do not have it just on my fingertips here.

Here it is. It is pages, basically with preamble and questions, pages 80 to 84 of the transcript.

A MR. CAMPBELL: Okay, if people have that exhibit in front of them -- or has it been assigned an exhibit number already?

MR. LANDRY: No.

A If people could turn to page 21 of the overview, which is Exhibit B-2, I think it might be helpful, of the overview, because the questions relate to some updated numbers flowing out of that table. It is a table of the comparison of the capacity criteria.

So we understood the undertaking to basically be in two parts. The first part was to identify the actual 2005 peak demand seen by the WAF system,

and also to provide an update of the 2006 year-to-date peak demand that has been seen on the WAF grid. Just as a supplemental, there was also a request to update the surplus or shortfalls using the three different criteria, i.e., the old criteria, the loss of load expectation criteria and the N-1 criteria. So that is, in effect, what this table does. The actual 2001 peak actually occurred January 13th of -- sorry, in 2005, so the 2005 peak number shown on the original table is, in fact, the correct number. It turned out to be the actual peak demand for that year because, of course, the document was prepared the latter half of that year, but, in fact, as we know, the winter, from 2005 to 2006, was a relatively mild one, so we did not set a new peak in the fourth quarter of 2005. So it is basically showing that the criteria is unchanged, of course, and the shortfalls and the surpluses are unchanged from the original filed document in B-2.

The peak demand to date, I'm pleased to say, was set yesterday, last night actually. And the actual peak demand was 52.9 megawatts. That, of course, includes, at this point in time, secondary

sales. So I have subtracted 4 megawatts off of that number for the secondary sales coincident peak demand, and added 600 kilowatts back on for the generation that Yukon Electrical self-generate at the Fish Lake Hydro Plant. So that is how I arrive at the 49.5 estimated firm peak demand on the system for the year-to-date, 2006.

I thought of interest to the Board would be -- that, of course, occurred yesterday with an average temperature of minus 24 degrees Celsius. There was currently a very good correlation from temperature to peak demand, that works out to 400 kilowatts per degree C change. So if you simply extrapolate minus 24 to minus 44, which was the temperature, for example, for the peak demand that occurred in 2005, I believe, then you can estimate what a new peak would be if we saw some seasonally cold weather. And, again, I have done that in the third row of numbers there. So if we see some cold weather, in the minus 40 degree C range, we will see the peak demand, based on the highest one we have seen to date this year, hit 57.5 megawatts, which is within 100 kilowatts or so of what our forecast peak demand was in our original filing.

I would like to note that there are a number of variables that affect the peak demand on the

system. It is affected first and foremost by the temperature. It is very temperature dependent. It is also affected by the day of the week. Mondays are high. Fridays are high. Statutory holidays are high. During the week, it is not quite as high. So it is a question of when you get the cold weather, what day of the week does it start at, how many days does the cold weather continue? People tend to get lazy, or they may not plug their block heaters in the first day, but by day two or day three, they will start to. You will start to see users of wood heat get a little tired or stoking the stove and start to turn on the electric baseboard heaters that they will have for backup in some of their homes. So, again, if you have a number of successive days of cold weather, the peak will creep up each day.

It is also affected by the time of the year. Because of the reduced daylight hours that we get in December/January, you will find more cases of where, for example, there is more street lighting staying on at the time we are seeing the peaks.

Our peaks typically occur from eight to nine in the morning and from five to six at night during the week. They are at a different time on the weekends, but if the street lighting is on, that

adds a couple of megawatts, if they are on at the time that the system is peaking as well.

So there are a whole bunch of factors that make it difficult to predict with accuracy what the peak will be every year, so we tend to average it out and pick some reasonable days, some reasonable forecasts, and so far they have been actually fairly close, subject to adjustments for weather.

MR. LANDRY: Can we mark that as the next exhibit, Madam Chair, please?

THE CHAIR: Do we have a number, Deana.

MS. LEMKE: B-20.

THE CHAIR: B-20 so marked.

MR. LANDRY: Thank you.

EXHIBIT NO. B-20:

YUKON ENERGY'S UNDERTAKING #3.

MR. LANDRY: The next undertaking

was questions relating to line losses and the capability to improve on line losses, and therefore affect the issue of capacity shortfall. And these questions and preamble come from pages 84 to 86 of the transcript. And Mr. Campbell has a handout for that and will respond to that undertaking.

A MR. CAMPBELL: Last night, when we were trying to answer this question, we read

through what we thought the questions were, so we will attempt to ask what the questions were.

The first question, as we understood, was what are the system losses that we have been seeing? The second question being, what are some potential projects that could be undertaken to potentially reduce system losses? The third question being more specific to transformers, and what is the potential to change out or upgrade transformers, again to reduce line losses?

With response to the first question, what we did was basically look yesterday at what our actual line loadings were on our main transmission lines,

and we attempted there to quantify what the losses, we are currently seeing under today's weather conditions and line loadings, are. And if you add up our two major lines, for example, the loss is about 6 percent on a medium to higher loaded line, to Aishihik, and again a much higher percentage line loss number on the line to Faro, for example, the total comes up to 2.3 megawatts. So potentially on the table, if you could reduce those losses to zero, you could save 2.3 megawatts.

I would note, though, that is not a very big number to deal with, the potential to save 2.3 megawatts. Now, I will get into the difficulty

in trying to achieve any realistic reductions at all.

There is basically -- if you want to reduce line losses, there are three primary ways that utilities look, from time to time, at doing that. The first one is to do a voltage conversion to a higher voltage. A higher line voltage reduces losses on the system.

The second one is to re-conductor the power

line with a bigger conductor. Again, lower resistance, you reduce your losses on the line.

The third one is, can you install a different transformer with lower losses?

All of these things, in themselves, are virtually always taken into account when you are designing that equipment or that system for the first time, and there may be opportunities in optimizing the selection of equipment to achieve some losses at that point in time. Unfortunately, it is extremely expensive, with very little benefit, to upgrade after that equipment is put into service. There are some opportunities if the equipment is at the end of its useful life and you are overhauling or rebuilding it, where there are some opportunities, and we have given some examples in our response here, for example, when we re-round

the Aishihik generators over the past few years. The one that was just completed, for example, for a very small incremental cost, we were able to improve the efficiency of the transformer, reduce

the losses, by putting more copper into it, effectively.

Recently, when we have been purchasing new transformers, we certainly have been using a newer more up-to-date higher cost of line losses when we evaluate different transformers, and the purchase is made based on the life cycle cost of operating that transformer. What we have seen, for example, though, in the past year, because of the increase in copper prices and stuff, transformer costs are going up, and even using a higher cost of losses, the optimum purchase price, from a life cycle standpoint, actually has been going the other way to produce a cheaper, slightly lossier, transformer. But overall, because line losses are only a relatively small percentage of the overall capacity of the line, there tends to be -- your savings tend to be a couple of percent, on a relatively small percent to start with, so the actual savings are very small. And from a capacity standpoint, there is virtually no material way you are going to achieve any type of savings that will

allow you to reduce your capacity requirements.

MR. LANDRY: Madam Chair, can we mark that as the next exhibit, please?

THE CHAIR: That is B-21, so marked.

MR. LANDRY: Thank you.

EXHIBIT NO. B-21:

YUKON ENERGY'S UNDERTAKING #4.

MR. LANDRY: And the last item I have, Madam Chair, is that Mr. Morrison would like to make a correction to the record, and my reference is page 87 of the transcript.

A MR. MORRISON: That is correct, Madam Chair.

I would just like to clarify, I may have left a wrong impression yesterday when answering a question from Mr. Pinard. It is page 87, and in the first few lines of that page, I had indicated that secondary sales customers and industrial customers are the same. And I just want to be clear that industrial customers are firm customers, they are not secondary sales customers. I was trying to use as an example in terms of backup, but I think I may have kind of lumped them together where I should not have.

So in the secondary sales situation, when we

reach the capacity in terms of the grid and we have to look at the peak, our practice has been that we have disconnected secondary sales customers if, in fact, to keep them on the system would require us to generate some diesel. So we do not provide any secondary sales if, in fact, we have to go a diesel mode to provide them.

In the case of industrial customers, they are firm customers. Now, in terms of an emergency, we have made it clear to the industrial customer, and we have made it clear, I think, yesterday as well, that the industrial customer would have to have its own backup supply on site. But I just wanted to make sure that we were not considering both industrials and secondaries as the same kind of customer.

THE CHAIR: Thank you, Mr. Morrison.

MR. LANDRY: Those are all of the items that I have, Madam Chair.

THE CHAIR: Thank you.

Mr. Buonaguro, are you ready to proceed?

Q MR. BUONAGURO: Yes, I actually have two quick questions.

The first I discussed with counsel. With respect to my questions on Marsh Lake and the cost

of Marsh Lake, I have information that there may have been a particular specific report from a firm called Gartner Lee. I do not know about it, but it may be there. And I would just ask for YEC to take a look at that to see if there was a specific consultative report done for Marsh Lake and, if there was, what the cost was.

A MR. MORRISON: Certainly, we will do that.

Q Thank you.

The second question also is related to my questions on Marsh Lake. We talked about the hydrology reports, and it has been explained to me that one of the reasons you do those is to try to look at potential increases to the potential output of the Whitehorse Dam. Are you able to give us what the potential is there for improvement in terms of going beyond 24 megawatts?

A No, we cannot at the moment, because we have not

done the hydrology studies. That is part of doing the work.

Q I thought that might be part of the answer. Is there any sort of guesstimate, potential ... nothing?

A Not a good thing to guess at. I am going to try not to do that at this time if that is all right.

We need to look at the system. I would like to kind of reiterate, though, that some of the reasons of doing Southern Lakes hydrology is that there are other projects potentially out there in that watershed, and we need to look at some of those as well. So it may not just relate to the Whitehorse plant, is the point I am trying to make. But I would hesitate to guess at anything at this point.

MR. BUONAGURO: Thank you. Those are my questions. The only thing I could think of is, reviewing some of the undertakings, something might pop up, and I might ask for your leave to jump in this afternoon, but I do not anticipate that being a problem. Thank you.

THE CHAIR: That would be the extent of your comments and cross-examination at this point?

MR. BUONAGURO: Yes.

THE CHAIR: I see, at this time, we have had another intervenor walk in the room who has indicated they would like to do some submission to the Board.

Is that true, Mr. Tuck?

MR. TUCK: That's me? Yes, I have some questions for Yukon Energy.

THE CHAIR: Are you prepared to proceed?

MR. TUCK: Yes.

THE CHAIR: Please do so.

YEC PANEL CROSS-EXAMINED BY MR. TUCK:

MR. TUCK: So my name is Wayne Tuck. I am Manager of Engineering, Environmental Services, with The City of Whitehorse. And I thank the Board for allowing me to speak or ask questions. I apologize for not being here earlier,

but ... working with Council and trying to figure out how we are going to pay our electric bills next year.

Q MR. TUCK: I just have a few questions regarding the vision submitted by Yukon Energy. And initially I would just like to know, what is the role of the Utility Board in the reviewing of this document? Do they prepare recommendations that they are required to follow, or what is the net result?

THE CHAIR: I am sorry, are you directing your question -- who are you directing your question to?

MR. TUCK: To the Board, to the Chair, to you, I guess.

THE CHAIR: Ms. Marx, would you

have some comments on that matter?

MS. MARX: Well, I guess this is not the appropriate time for asking questions of the Board. Your opportunity right now is to ask any questions you have of Yukon Energy. So I would ask you to proceed on that basis.

MR. TUCK: Excuse me, I am new to this. I just needed --

THE CHAIR: That's great, that is totally understandable.

MR. TUCK: So I was just wanting to find out what the --

MS. MARX: For assistance, Mr. Tuck, I can just indicate that the government, in its letter to the Board, directed the Board to submit a report, with recommendations to the government, on the Plan.

Q MR. TUCK: In regards to that recommendations, is Yukon Energy then obligated to follow those recommendations, or are they guidelines?

A MR. MORRISON: Don't ask me.

THE CHAIR: I don't know if the right person is here to answer that. It's a report to the Commissioner in the Executive Council, under directive. If you look in the transcripts of day one, we mentioned it in the background, in our

opening statement, in the background on how we have come to the point of where we are to date in this oral proceeding.

Q MR. TUCK: So my question then is to Yukon Energy: Are you obligated, then, to follow the recommendations that have been identified in the decision made by the Board?

A MR. MORRISON: It depends on what form the recommendation -- we are not obligated to follow any kind of recommendations, but we are obligated to do certain things under our Act, or under the YDC Act, and we are obligated to do certain things that the Minister has power to give us direction on, subject to that Act and the YUB Act. So it depends on what form the recommendations come in.

I will say that, in terms of those kind of approvals, if that is what we are talking about, that Yukon Energy is required to get approval from the Minister before proceeding with major projects such as the Carmacks-Stewart line.

Q Okay. Currently, from the City's perspective, we are concerned not only from the financial cost that will be impacted on the citizens of Whitehorse, but also from an environmental perspective, the impact

on the continued operation of the diesel plant in the location that it is now at. We see certainly a move, and a significant move, into trying to use up as much excess hydro power as possible. And we all know that we have way more excess power in the summertime than in the wintertime. So my question to Yukon Energy is, as a Crown corporation, do you only look at financial costs of a particular project or do you consider environmental costs; i.e., not only greenhouse production issues, but pollution caused by the operation, or noise pollution, that type of thing?

A I think I can tell you that we look at a whole series of factors when we make decisions and we put forward proposals. We are required, as everyone else is, to follow the regulatory guidelines in terms of environmental standards. We have permits for the operation of our diesel plant. Those permits are renewed on a regular basis.

I think if you will refer yourself to the Plan, you will see that we don't plan, in anything in this 20-year Plan -- you know, it is our anticipation that we won't be using diesel for base load except on the margins. And if we could find a way to get hydro or some other renewable resource

on stream to meet those demands, we've certainly

indicated, I think fairly clearly, that we would be looking at those.

Q And the City is certainly in support of some of that initiative in order to reduce the reliance on the diesel plant.

I was just curious, in the B.C. Utilities Commission decision that was made in 2003, it specifically identifies or talks about costs associated with operation of a diesel type of turbines or generating of greenhouse gases, and there is a cost perspective, and I was wondering whether you have incorporated -- I know this plan doesn't incorporate that, but whether, in fact, you would consider that type of cost as a result of the operation of a diesel plant?

MR. LANDRY: If I may, just to be careful again, and again, not to be critical of Mr. Tuck who I know is trying to get where he wants to go, but the premise of that, I cannot -- I am not even in a position, and I think I was at that hearing, to confirm that that is the case. I just

want to be careful that that is not taken as a given. So really, I guess, what I would ask is that Mr. Tuck just ask the specific question that he has, as opposed to referencing back to the B.C. Utilities Commission ruling.

THE CHAIR: Mr. Tuck, would you proceed on that basis and ask the specific question, without referring back, and I concur with Mr. Landry on that point.

Q MR. TUCK: I was just referencing because I received a copy of the B.C. Utility Commission report from Yukon Energy, and within that they talked about clean energy and the cost of environmental, so that was my question, whether in fact they have included or considered that cost, or a type of cost applicable to the Yukon.

A MR. MORRISON: Madam Chair, I think just to help try to advance this, you know, at the moment, and I think there was evidence yesterday, or testimony at least yesterday, that indicates that Yukon Energy generation is 90-some percent,

and I cannot remember the exact number, but -- we don't have any baseline diesel generation on the system. We would prefer not to use diesel, at all, if we did not have to. This is not a question, in some cases, of a preference. It is, in some cases, a question of cost/benefit, not just the environmental cost, but also the dollars and cents cost. So we do look at the whole package.

We have taken, and I think it is illustrated in this Plan that our efforts have been, or are,

under this plan, to enhance the capacity of the assets that we currently have, which is an economic benefit, we believe quite strongly, because we are utilizing the assets to their fullest extent and thereby extracting the greatest amount of benefit from those assets. And when we talk about using those assets, we are talking about our hydro plants and our transmission grids.

It is Yukon Energy's proposal to construct the Carmacks to Stewart line, and it is for several reasons. But one of those very specific reasons is so that we can reduce the potential greenhouse gas

emissions that would be generated by the Minto mine, the Carmacks-Stewart line, and that continue to be generated by the community of Pelly Crossing. So I think we have demonstrated, you know, quite clearly, that our efforts, certainly within this planning period, are designed towards doing or making the best effort we can to reduce greenhouse gas potentials where possible.

There is no potential, in my mind, Madam Chair, to get rid of the diesel plant in Whitehorse. It is a valuable asset that is there. The best of all scenarios is that we simply maintain that plant in an emergent or back-up situation. And if we use it a few hours a year, at

the moment, that is the best alternative we have, both for ratepayers and from an environmental perspective.

Q And I think it is great, I think it is great from a greenhouse gas reduction perspective. Certainly the changes that have been made already is significant.

In specific about the diesel plant where it is located in the river valley and primarily in the downtown core, have there been any discussions or plans to look, from an emergency measures perspective, in this close proximity to the dam and/or an environmental impact to the citizens who live and work and visit Whitehorse? And I am thinking specifically, like, in the wintertime when we have air temperature inversions that quite often occur, the pollution that would result as a result of the use of that diesel plant in the valley. Has there been any discussion about moving that plant?

A Well, no, we have not had any discussions about moving that plant, and I would be very clear with you that we have no intentions of looking at moving that plant. It is a very costly effort. There's 22 and a half megawatts of capacity down there. Would we build it there, you know, if we were starting from scratch? Perhaps not. But it exists

there today. And the cost of moving that plant, when we don't utilize, we don't run those engines very often, it is a very minimal number of hours

per year that they are utilized, and I do not think that we could come to this Board and justify the cost of moving it based on the number of hours that those diesels are used on a year-in/year-out basis.

Q In regards to the long-term nature of this Plan, like looking 20 years and beyond, has there been any discussion or consideration for the concern about what fuel oil prices will be and how it relates -- I am specifically relating to other green-type projects in relation to try and minimize the operation of the diesel plant even on emergency or back-up perspective?

A I think if you will recall, there are two pieces to the plan. There is a piece about projects that talk, that need to be done in the very near-term, and none of those are projects that deal with the increase usage of diesel in any way. In fact, Aishihik, again, is a project to take diesel off the margin.

In the future, all of the projects that we are talking about looking at, in terms of future planning, are all renewable, so we are not talking about building any diesel where we do not have to.

And there is no intent to run the diesel any more than we absolutely have to. So I am not sure if that helps you, but that is what the Plan contemplates.

Q Okay. In the 1992 Yukon Board decision, reference is made to the potential of Yukon Electrical to develop a hydro plant at McIntyre Creek, or expand their hydro facilities, which would work out to 6.4 megawatts of power according to the YUB decision. And I guess the reason why it wasn't or has not been expanded on is because it related to land claims negotiations. Well, those are now completed. And Yukon Electric, I understand, has had discussions about water licence approval and expanding their facilities.

Have there been any discussions with Yukon Electric in coordination with what their plans are regarding power supply, so that we don't get a duplication of effort and we don't spend?

A Madam Chair, I want to clarify something for Mr. Tuck. First of all, the McIntyre Creek project is not 6.4 megawatts, it's .64 megawatts. It is a very small project.

I have no understanding from Yukon Electric that they are pursuing this project. You would have to ask them that, but it is my understanding

they are not pursuing it at this time.

Q Well, I was just going by what was quoted in the report so --

A Mr. Tuck, what I am trying to point out to you is your number is wrong. It is not 6.4, it is .64. It is a very small project.

Q Okay. It was quoted in the YUB report.

So granted, but it goes back to my question, has there been any discussion about -- with Yukon Electric -- you guys are both in the business of supplying some hydro power, some power supplies, and the importance of -- given that they supply power to a bunch of -- about discussions with them on plans, future plans?

A Madam Chair, I understand Mr. Tuck wasn't here yesterday, we did talk about some of this, but I think, just to be clear again, we have had discussions with Yukon Electrical. We are aware of no plans on their part to build a McIntyre Creek project.

Q Okay. So it just says in Section 7.5.3.3.2 in the YUB 1992 decision, it references 6.2 megawatts of

dependable power. So that is why I thought it was --

A It is not that big of a project, I can tell you that.

THE CHAIR: That appears to be an error.

Q MR. TUCK: Okay, that is fine. The YUB decision goes on quite a bit about industrial power producers, and establishing opportunities for that to occur. And if I ask you a question that has already been asked, you can just say it has already been asked, I am just trying to emphasize, from our perspective, the importance of certain issues, and I do not mean to get you to repeat stuff that has already been dealt with.

A MR. MORRISON: That is fine.

Q But I think, as we see more technologies and more expertise occurring in the private sector in regards to green power supplies, and either photovoltaics or wind power, technology is evolving and it is becoming much more cost-effective for

IPPs to be joining in. So I am just wondering, have there been any discussions or opportunities put out there for people to start an IPP or to be an IPP?

A Madam Chair, when we look at IPPs -- and we talked yesterday about, you know, an IPP policy, and the fact that we don't have one, but at the movement, Madam Chair, we have a surplus of hydro on the

grid. So it would not be our intent to put forward any call for people to submit proposals to us to supply power because we don't need to buy any power at the moment. We have enough power on the grid, and both grids, Mayo-Dawson and the Whitehorse-Aishihik-Faro grid.

We also, I can tell you, have not had anybody bring forward a proposal to us, either, to build any independent power project, of any kind, in any formal manner whatsoever. We, from time to time, get people interested in, or having ideas that they may want to expand, and they certainly come in and get information from us, which we provide on a

regular basis to individuals and corporate companies who have ideas about providing power or generating power. None of those ideas have ever resulted in a proposal being given to us, and in general, it's a question of timing and opportunity being there at the same time. We don't need any power right now, so we have a surplus of renewable. So when do we need it? And I think we have outlined very clearly in the Plan that, absent mine contracts, or mine customers, we have enough power for quite a while in the system that we have. So it is a little bit of balancing both of those, and I think at the moment we are petty clear

that, if people come to us with a concept and an idea, we are prepared to discuss it with them. We have no aversion and no policy that prohibits us from doing that.

But Cam, do you want to add a little bit?

A MR. OSLER: Just add two things. One, if you are interested in sort of a review of what our thoughts have been on this matter, you can look at Section 5 of the original document, the

January document, pages 5-36 through 38. And in that, my second point is, YEC, when there was power needs in the system with diesel, did set out its own call for expressions of interest to all parties, in 1996, for any ability for IPPs to come forward anywhere in the Yukon to help generate power, and it got a bunch of proposals at the time. Unfortunately, all of that got supplanted by the shut-down of the Faro mine early in the next year.

Q And regarding that, and I understand that you have signed, now, an agreement, or there is an agreement with the Minto project, and they will be required to ensure that in the -- when available -- hydro power is not available, that they have to generate their own power. So is there an opportunity with their own -- is that correct; that when there is

not availability of hydro power, that they have to generate their own power on site?

A MR. MORRISON: Let me say it my way, Madam Chair. The mine, as part of any agreement

that we reach with them, and we have not reached any conclusive agreement with them, will be required to have on-site back-up power that they will be required to use in an emergency situation.

Q I am not talking about emergency situation, I am talking about -- I mean, I certainly agree that emergency situation, everybody has to be on side, but I am talking about, we know that there is a surplus of hydro power in the summertime and in the fall. In the winter and the springtime, when water levels are low, or water levels are low historically, then there may be an issue, then, that we don't have enough hydro power, in which case, then, you may be required to activate the diesel plant in Whitehorse to service the mines up in --

A And Madam Chair, we have, in front of us, a proposal to build the Aishihik Third Turbine to mitigate that need to burn diesel at the margins.

Q Okay. So it is still the issue, it is going to take a couple of years, because I think you are building -- isn't it the first phase coming from

Whitehorse, upwards to Minto, and not coming the other way around?

A No, the proposal is to build the project from Carmacks, north.

Q Right. But the surplus of power, hydro power, is actually --

A The surplus --

Q -- from Mayo. Is there not --

A No, no.

Q -- surplus of power in Mayo?

A Madam Chair, there is a surplus of hydro on the Mayo-Dawson system, and it is a small amount of surplus. There is a large amount of surplus on the Whitehorse-Aishihik-Faro system. We don't propose to sell power to Minto mine, or any mine, including Pelly Crossing, from the Mayo system. We plan to use the surplus available in the Whitehorse-Aishihik-Faro system.

Q So they are provided -- required to have their own back-up power supply. So is there an IPP opportunity for them to join in, and when there is a shortage of hydro power or an emergency situation, that you might be able to buy power from them as a result of their expenditures of diesel?

A Well, Madam Chair, if we need to generate diesel on the margins, we would buy our own diesel, we would

use our own diesel power, we would not need to buy it from the Minto mine. So I am not sure if that is the question or not, but --

Q Well, it was just an opportunity for an IPP, they have this facility that is sitting there and if they are generating -- I am not sure what the excess power --

A But we have enough diesel in our system, we would not buy it from somebody else.

Q But you still have to provide power and line losses all the way out to their facility up in Minto, right?

A Yes, that is true, but, you know, we would have to buy it from them. We already have it. We have plant in place.

Q And the concern that I have raised already is about operating the diesel plant in Whitehorse, in the river valley, more often as a result of the need to supplement a shortage of hydro power?

A I probably get a glare from my legal counsel for this, but you are saying it is better to -- it is okay to burn diesel out at the Minto mine, but it is not okay to burn diesel in Whitehorse.

Q Generally, I would think so. I mean, I'm not a --

but I would think so, yes.

So, in 1992, there was reference to the amount

of peak power that we generate, in 1992, compared to what, currently, the Whitehorse area requires, and it has gone from 40 to 46. And so, over the last 15 years, we have seen a significant increase in power consumption, whereas, there has not been a significant increase in population. I am not sure exactly numbers, but from our perspective in '92, the population is fairly similar to what it is today. So what we have seen is more consumption, higher consumption of power, and the Utility Board decisions that were made -- identified a number of recommendations, like seven or eight recommendations, regarding the importance of demand side management, and the need that Yukon Energy and Yukon Electrical need to work together to reduce requirements of people on using power, and try to reduce their loading in order to avoid having to do undue changes. And I am curious as to what DSM programs have been undertaken, to any significant

degree, and do you not see a need to expand that in order to meet the terms of the 1992 decision.

MR. LANDRY: And Madam Chair, I will assume, for the purposes of the record, that it is the question at the end that has to be answered, without all the assumptions or preamble that went with that question.

THE CHAIR: Mr. Tuck, would you like to proceed on that basis?

MR. TUCK: Sure. So I am not sure -- I thought it was all connected, so I am not sure what you are trying to state there.

THE CHAIR: Would you like to restate your last question, your final question, possibly just for clarification, for clarification purposes, unless --

MR. TUCK: I have to restate it?

MR. LANDRY: I think Mr. Morrison understood the question.

A MR. MORRISON: I am okay. Madam Chair, you know, again, from a DSM perspective, you know, a major program that we have in place is our

secondary sales program. Major DSM program. If the reference to the 1992 Board report has not addressed, in the question, the fact that we have -- (a), we have a surplus of hydro on the system, and we had a surplus of hydro on the system at that time, and we were advised by the Board, at that time, not to proceed with expenditures related to DSM because we had a surplus of hydro on the system, so that would be my answer.

A MR. OSLER: And just because it might come to you later, there is a second question

that has been put to us by others, Yukon Conservation Society, if you have a surplus of hydro, why are you not at least looking at DSM for this capacity shortage that we do have. If you were here, we have been through the fact that we have a capacity shortfall which is different than an energy surplus, and we have been talking about that a bit, if you look at the answer to YCS-YEC-2-A2 to find out what our response was to that question. So, bottom line, we have looked at

DSM from the point of view of implementing it for helping people use surplus hydro, that is called secondary sales. We have paid attention to the Board's direction and common sense, that if you have an energy surplus, you do not want people to consume less energy at the moment because it will just raise rates, and we have looked specifically at the issue of, is there a DSM plan that we should be thinking about to deal with the capacity shortfall. And the bottom line is, it would be too expensive, and there isn't a practical set of options there.

Q Certainly I can understand that if you have a surplus of hydro power, like you have had before, I can understand that you do not want to spend money in order to actually make less money.

However, it takes time for people to change the way they operate, the way the facilities they operate, the mechanism, and it takes time, and you cannot expect all of a sudden, I would think, unless you can correct me, but you cannot expect the people to, once you are in a deficit situation,

to get people to change their habits, because it takes time and material to make those changes. So I would think, in order to be proactive, you need to start now, don't you think?

A MR. MORRISON: To start now doing what?

Q To start, and should have been starting, doing some DSM programs in order to release that. I know, I can understand that your issue -- you are saying secondary power, you are actually increasing power consumption, not dealing with trying to reduce peoples' reliance on power. With secondary power sales, it is a way to increase -- it was intended to increase your revenue, which was otherwise being dumped down the stream, and it actually doesn't work towards reducing peoples' reliance on power?

A MR. MORRISON: I am not sure, Madam Chair, if I have a question, so if you have a question, I would be happy to answer it.

Q So basically, so my question is, are there no plans

now? You are saying that the Board has told you

not to spend money on DSM programs?

A I said to you -- Madam Chair, what I referred to was in the 1992 Board -- 1993 Board Order that was -- that Mr. Tuck was using. I just further pointed out to him that we had been advised that DSM expenditures, while we had a surplus of hydro, were not a prudent expenditure on behalf of ratepayers. We have no plans, at the moment, to look at further DSM because, again, we still have a continual surplus of hydro on the system.

A MR. OSLER: If I could just add one thing, from the '92 experience, '92 hearing, one of the things we talked about, that creates electrical requirements, the long run, but doesn't make a lot of sense, efficiency-wise, was electric heating, particularly if we end up with diesel back on the margin. Not much that Yukon Energy can do about whether residential or commercial -- residential people, in general, served by another utility, install electric heating because it is convenient, or the rates are being subsidized, or whatever. Government could; it could institute ground rules. Other people could. That's the type of thing that 10 years, 15, 20 years from now, if diesel was on the margin, a lot of new electric heating would

come under purview of people at this review level, as to what effects it was having on overall efficiency, environmental emissions, whole bunch of other things. So it doesn't mean, because Yukon Energy is not able, under its mandate and the things it can deal with cost-effectively, to pursue these measures that you are talking about right now, it doesn't mean that somebody else could not or should not.

Q I am glad you brought up the issue of electric heat, because the City is actually seeing commercial businesses and residential businesses installing electric heat. And certainly with Yukon Energy's desire or drive to make as many sales of hydro power as possible to make up that shortfall, certainly we are sort of seeing a repeat of the electrical heat problems we had -- well, before I came in the '80s. And Recommendation Number 31 from the Utility Board specifically says that you and Yukon Electric need to take steps to reduce and eliminate electric heat supply, and that is one of your conditions. And certainly one of the issues that I would see an Energy Solution Centre or that type of DSM program that, if you had implemented and expanded on, we may not have seen that issue.

And I was just wondering like, what steps have you,

in accordance with Recommendation 31, taken to ensure that electric heat is not provided?

A MR. MORRISON: Madam Chair, Mr. Tuck is referring to customers of Yukon Electric. The City of Whitehorse is served by Yukon Electric, and I think he is referring to this new building that is going up. If you look out the window here, there is a condo unit here, and other commercial buildings, that we understand are being built with electric heat services in them. Those are customers of Yukon Electric, you are going to have to ask them.

I would also point out to you that the issue of electric -- or the Energy Solution Centre reference that you have mentioned to us is, you know, if the Energy Solution Centre has programs related to the reduction of electric heating, or the reduction of greenhouse gases, or whatever their programs are, those are their programs, and you are going to have ask them those questions, but that is not Yukon Energy.

Q I thought they reported to you?
A No, they report to the Department of Energy, Mines and Resources, they are part of the Yukon Government.
Q Okay. But anyways, in regards, it doesn't

specifically say, it just says Recommendation 31. If you read it, it says you are supposed to work cooperatively with Yukon Electric to come up with ways of doing that. So, basically, nothing has been done on that?
A Madam Chair, just to be clear, these are -- this is not a Yukon Energy service area, and I would not presume to be telling Yukon Electric how to deal with their customers in their service area.
Q Well, okay. As this Resource Plan comes to 20 years and beyond, and you spoke about an energy -- and I can appreciate that you said that there is an energy surplus but not a capacity surplus. However, in order to -- you have a wind generation power.
A Right.

Q And certainly, in the long term, as ways of reducing increasing capacity, or using less water, or hydro power in conjunction with an operation of a green power, is there not an opportunity to, in the long term, expand and take advantage of changes to wind power so that it can provide and meet up the shortfall, in the event, to avoid the operation of the diesels, even to a small degree that has been mentioned before?

A Madam Chair, wind power provides no capacity

enhancements at all. Capacity enhancements have to be a plant that can be reliably turned on at the time that you need the capacity. Wind power is only energy. You cannot count on it. I am happy to have either Mr. Campbell or even Dr. Billinton, if he would like, to talk about the reliability issues around wind power.

I have advised Mr. Tuck previously that wind power is also very, very, very expensive. We believe that our cost of producing a kilowatt hour of wind on the Haeckel Hill wind plant is about 31 and a half cents a kilowatt hour. So not only is

it not economic, it is not reliable in terms of capacity. The capacity factor with which the two plants on Haeckel Hill operate is about 15 percent, and I do not think that anybody wants us to take the chance that the wind power is going to -- the wind is going to operate if we have an emergency. So, therefore, you cannot count wind as capacity, it provides energy only.

Q And I agree. And I think I prefaced my comment about that I recognize that it is not a capacity provision. It is more or less the opportunity to use some power, whatever is available, in order to reduce the reliance on the diesel system.

A And Madam Chair, I think that is exactly what we do

with our two plants. We have no potential new wind sites advanced to a stage where we would look at them in terms of bringing them on stream. We have looked at a number of sites, you know, over the years, but nothing that gives us any commercial viability. We still are doing some work on a site at Ferry Hill, which is, to put it in perspective

for people, is just outside of Stewart Crossing, but right adjacent to the grid, the Mayo-Dawson grid, and there may be, in the future, some potential there. But we have no other sites in our inventory that would be at a stage, or in a condition, where we would think about developing them.

Q Well, I am not sure, so can you provide that information? You said it was 31 cents-per-kilowatt hour, is that information that can be provided, and is that something you can also compare to what it operates in regards to operation of the diesel plants, for example, when it runs?

A Madam Chair, if I could get some clarification around that, I have already provided it, that is the analysis that we have done, that is the cost. In comparison to the diesel, diesels are virtually -- you know, maybe Mr. Campbell can help me with the number -- 80 or 90 percent reliable, or

operating factor?

A MR. CAMPBELL: 90 percent.

A MR. MORRISON: 90 percent is the

operating factor that we use for a diesel plant, and our experience with the Haeckel Hill plant is that it is about 15 percent.

Q So is it a part of the cost in regards to where this Haeckel Hill -- the fact that there's only two windmills and the fact that the access road is not all that accessible, and certainly with an availability of surplus hydro power, there is not a desire to keep it in operating condition?

A Well, Madam Chair --

THE CHAIR: Mr. Tuck, I think the question has been answered.

Q Okay, that is fine. That was it. That was all of my questions. Thank you.

THE CHAIR: Well, I note it is quarter to twelve, and it is probably an appropriate time to break for lunch. In that case, we had talked about reconvening at 1:30, shall we make that quarter after one?

(Proceedings adjourned at 11:50 a.m.)

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