YUKON UTILITIES BOARD

YUKON ENERGY CORPORATION 20 YEAR RESOURCE PLAN
APPLICATION TO THE YUKON UTILITIES BOARD

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BEFORE BOARD MEMBERS:

Wendy Shanks	A/Chairperson
Brian Morris	Member
Richard Hancock	Member
Michael Phillips	Member

BOARD COUNSEL:

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

TRANSCRIBER:

Doug Ayers Reporting Services

(Proceedings resumed at 1:15 p.m.)

THE CHAIR: Mr. Landry, do you have some comments.

MR. LANDRY: Yes, Madam Chair, I have one more undertaking to respond to, and hopefully we will have -- I think there is one other besides this one, we will have something today, later on. But it is the undertaking in relation to the question concerning Gartner Lee and Marsh Lake. Mr. Morrison is going to provide the response, and I do not have a page number yet. So, Mr. Morrison.

A MR. MORRISON: Thank you, Madam Chair. Just in reference to the question, the undertaking from late this morning, I had answered a question about the cost of consultation, and

I had indicated that it wasn't a very significant amount of money, and I think, later on, was asked by counsel for UCG if I had a cost for the Gartner Lee, or the study work that was done on the Marsh Lake Storage Project. I would refer everyone to UCG-YEC-2-29, and in answer to that question, we indicated that the field work, which was done by Gartner Lee in reference to the Marsh Lake project, was estimated at a $45,000. We still have not been invoiced for that work, but I will tell you that it

is the $45,000 or less.

THE CHAIR: Thank you, Mr. Morrison.

A Thank you.

THE CHAIR: On that, Ms. Marx, are you prepared to proceed?

MS. MARX: Yes, I am, thank you.

YEC PANEL EXAMINED BY BOARD STAFF:

Q MS. MARX: I have a couple of areas I would like to follow up on that Mr. Buonaguro discussed with you, and then I will turn my attention to the planning criteria.

First, with regard to the load forecasts, you have filed some information regarding the load forecasts, and the expected continued growth in the forecast. What I would like to know -- it appears to me, that over the past number of years, or in the recent past, there has been a fair bit of growth in Whitehorse in terms of commercial growth, and, specifically, I am thinking of the facilities that have been built for the Canada Games next year. There is, I believe, an athlete's village and the recreational complex, and there might be another facility as well. There are some of the big box stores, Wal-Mart, et cetera. And I understand that these new loads will, you know,

provide some increase to your load forecast, but in terms of significant, new commercial growth like that coming on, do you expect that trend to continue?

A MR. MORRISON: I think, when we look at the load forecast, we expect the trend to continue for different reasons. We have gone

through a period where we have seen some significant capital expenditure, which would be institutional; as you mentioned, the Canada Games facilities, those kind of things. We have also gone through a period where there was an increase in commercial development. I think if you look, you know -- if the weather wasn't quite as cold, and we all had an opportunity to get out a little more, you would see, around Whitehorse, that there is a significant number of new, and significant for Whitehorse, you know, I preface my comments, but significant number of new condominium units being built, including, I mentioned earlier, this building behind us. I think there are two, at least two others. My understanding is they are all on electric heat.

Q Go on.

A I just have a couple more points. We have also not seen any of the real impact, yet, of the growth in

resource development. So the current resource development growth has been in the exploration sector, and we have seen exploration spending, you

know, expand quite a bit. And that certainly has added to the growth in Whitehorse. But we are about to see, at least one if not more, new mines come in, which then provides a steady base of employment and income that should add to the already existing growth in the commercial sectors here. There are a number of new buildings planned, from the commercial side of things, over the next several years as well, so there is further development still coming on stream in the area where Wal-Mart is, and a few of those new developments. So for the next several years, we see this growth continuing.

Q With what you just mentioned about commercial growth that you are expecting in the area where Wal-Mart is, would you expect that it would be to the same magnitude as what has been seen in the past couple of years?

A I am not certain that -- if you mean magnitude, I do not think that we will get very many more single developments the size of Wal-Mart. You know, the Canadian Tire development is bigger than Wal-Mart, and it is due to come on stream sometime

next year, and I would think early next year, there is another large development down there. I think what it will turn to is more smaller developments. A lot of them, again, related to the internal economy. When we have the mine, and the salaries from the mine, and the suppliers of goods and services to the mine, those types of activities will create further employment, which will create further demand in the commercial sector. So our forecast is, in the next few years, that we see that trend continuing fairly strongly. All of it will depend on whether or not the resource development sector and/or other developments come along in behind the single mine that we now have.

Q Okay. With respect to the residential growth that you mentioned, the new condo complex or complexes --

A Yes.

Q I would not expect -- and I think this is what you were getting at, is that that is not going to contribute a significant amount to the load growth. It is going to contribute to load growth, and it is going to, maybe partly, make up for, as a trade-off, some of the commercial growth that has been seen recently. Is that a fair assessment?

A No. Not quite. I think what I was trying to say

is that, on the commercial side of things, we will see more developments of a smaller size than we have in recent years, so not so much the Super Store, Wal-Mart size developments, but smaller businesses that will either be -- that are either existing and expanding, or coming in to provide goods and services, you know, in a competitive marketplace as Whitehorse grows. And Whitehorse is growing, and has substantially, over the last few years. There is no immediate indicator, from our perspective, that there is a slowdown in government spending, which is a huge part of our economy; as a matter of fact, over the last few years, government spending has increased beyond what we would even have anticipated. So the City, as it grows, as a municipality, but the primary, you know, spender at the government level, is the territorial government. All of this creates the high level of activity that we have not seen, and we anticipate will continue to see for several years.

Q So would I be fair to say, then, that it is the continued small commercial growth, residential

growth, and that is going to, essentially, equal, continue the trend, that you have seen over the past few years?

A I think it is going to -- it is going to at least

equal the forecast that we have in the Plan. The difficulty I have with just saying yes to your answer, simply is that we are starting to see some really big spikes, and I think what we are looking at in the Plan is even some smaller levels of growth than what these actual spikes in the last couple of years are. And if this year is an example, given that we are going through a fairly continuing period of colder weather, our sales, again, are going to be -- they are going to be higher than we even forecast, again. And so I think when we come back to the 2.2 percent that we talked about earlier, and Patrick, you can certainly help me out on this, we are not anticipating -- you know, we are not forecasting 4 and 5 percent growth. You know, we are trying to keep our forecast to a reasonable level. So it is not the spikes that we see, but we think we are

going to at least maintain the 2-plus percent growth.

A MR. BOWMAN: I would just add that your comment was about continuation of trends seen in that Exhibit B-2, at page 24, that sets out the calculation of the growth rates that are used in the Plan. There are four different ways that it considers low to high scenarios. Both of the

higher-than-medium scenarios are based on recent experience. Both of the lower-than-medium scenarios are based on looking solely at general demographic trends, and the Plan takes something in the middle. So, if anything, the Plan is not reflecting continuation of what is seen at 1.85 percent, it is below what has recently been seen, as we reviewed this morning, which has been more in the 2.2, 2.3 percentage range. So, from that perspective, it is not sort of hinging on continuation of what we have seen.

And I would just make the comment as well, in terms of the Plan, compared to resource plans that

I have seen in other places, particularly in regards to the near-term scenarios, the types of projects that are talked about in the Plan hinge very little on the level of growth chosen. The low scenario to the high scenario do not change dramatically the type of number of megawatts of shortfalls that are needed. The shortfalls are really being driven by retirements and the change in the capacity criteria, and in the long-term scenarios, it is really being driven by large incremental changes due to mines.

So, in effect, although there isn't a need to look at the load forecast and the different

sensitivities to ensure -- on the one hand, to ensure that you are not over-building should the low scenario arise, and on the other hand, to make sure you are not caught offguard if the high scenario arises, it is rare to have a Plan that hinges this little on choosing the right percentage forecast.

Q All right. The other area I wanted to follow up on was with respect to the Acres Engineering Study,

dealing with the winter capacity at the Whitehorse hydro plant, and Mr. Campbell, my question will be directed to you.

In the 1992 capital plan, the report, the Board's report on that, referred to a need for further study related to ice conditions, and I believe I -- what you said yesterday, and I have not had a chance to look at the transcript, but I believe you said that, at that time, YEC did not go ahead with those icing studies because they did not consider it to be a feasible option because there was excess hydro capacity at that time. Is that a fair assessment of what you said?

A MR. CAMPBELL: Perhaps I should clarify. There were some additional icing studies done, I think the Acres studies went on to about 1995, but the results were not implemented because

there was little benefit and considerable risk. There was a need for some ongoing testing, modifying, the ability to prove that the modeling that Acres had been doing was accurate in terms of

predicting how far you could go with changing flows and not affecting the ice.

Q Okay. So I guess that further study, beyond the Acres study, is what YEC chose not to undertake at that time?

A Yes, basically the work on the icing stopped in around 1995.

A MR. BOWMAN: If it is helpful, the report that Acres put out in 1995, which summarizes a number of reports through the previous years, is filed in response to YUB Round 2, Question 15, and it is a summary of the different work they had done leading up to 1995.

Q Now, you indicated yesterday, Mr. Campbell, that YEC had just commissioned a study into the icing conditions, this further study. When exactly was that commissioned?

A MR. CAMPBELL: The work was scoped out and developed approximately three months ago, and the work was awarded approximately two weeks ago. We actually had a kick-off meeting with the successful proponent last week.

Q Now, given that your Resource Plan has been, I guess, in the works for some time, why would you not have looked at this -- or commenced this study sooner, as an option for providing additional capacity on the system?

A I think that is a good question. The response is that it is not a near-term option in terms of -- it does not have the ability to provide additional capacity next year. It is an option that does have the long-term capacity potential, and that's all it is at this point in time. But our guess is it will take several years to implement, if it is deemed to be feasible, because it will require some physical modifications to the gates at the Lewes dam control structure in the outlet of Marsh Lake, and it will take work with The City of Whitehorse, with the Water Resources group of the Yukon Government, and it may involve having to purchase some property in the Marwell area, or to providing some berming or some mitigation to some increased shoreline erosion due to icing and stuff in some of the low lying areas. So it is an option that we -- there is some potential, but I would not -- it is not a guarantee at all.

Q When did YEC first begin its work on the Resource Plan?

A The initial bit of the work was really started with the condition assessment work that B.C. Hydro, and that was really part of the first phase of the work which was -- the reports were filed in May of '04, I think the actual work was started in late 2003.

Q So what I am trying to understand is, I see that you are saying -- undertaking these studies, you know, you have got -- it is going to take some time, two or three years, potentially, before that could be implemented, but I am wondering why YEC would not have started looking at that back in 2004 when it was starting to work on the Resource Plan?

A MR. MORRISON: Well, Ms. Marx, if I can help, or Madam Chair, we are not a very big organization, and we have a fair length of priority -- the job -- or the work that we have to do is pretty large in scope, and significant in scope, from my perspective. We set some priorities, they may not always be the ones that other people might set. We have a very small engineering group, tech services group, that is responsible for prepping work, for looking at the work to see which is needed, setting the priorities. I think, as Mr. Campbell mentioned earlier, you know, we just

thought that this one could wait a little while. We have other priorities we thought we were putting

our efforts to, and that wasn't one of them at the time.

Q Would not it have made sense to look at this sooner if the potential is there to, perhaps, displace diesel generation, for example?

A Well, I think if the potential was, in fact, known, we -- you know, what the potential, or we could quantify what that potential is, and whether or not it is actually technically feasible, yes, that would have made some sense. But we don't know that yet.

Q Right. But if I take the Mirrlees Life Extension Project, for example, you would have had to -- you would not have known right away whether that was technically feasible either, you would have had to undertake all that study first to know whether it was technically feasible?

A That is correct.

Q So I don't know what the distinction is between

that project and this project, for example.
A I will give you a couple of thoughts on that, and then Mr. Osler thinks that he wants to make a couple of points as well.
In very clear terms, the potential on the Mirrlees side is very substantial, compared to what the potential possibly could be on the icing

issue. So we are talking about 11 to 15 megawatts on the Mirrlees issue, and we are talking about a small number, that may be as high as two or three or four megawatts, on the icing issue.
Q I recognize that.
A Yes.
Q And I guess what I am getting at is, you made the comment that you didn't undertake -- that you did not look at this possibility sooner because you did not know if it was technically feasible. But I would assume that there are a number of other options that you did not know whether they were technically feasible, but you undertook sooner.
A I am just telling you that we set some rankings and we did not rank that one as high in terms of

getting to it on a priority basis. So it has come up now, and we are going to look at it. But we don't have the luxury of taking a, you know, full shotgun approach to everything, and doing everything that we think might be feasible. I think there is also some question around energy and capacity, as well.

A MR. OSLER: Just to be helpful, Mr. Campbell has said that there was work done on condition assessments a certain period back. The Resource Plan, as you see it filed from B-1,

January, probably got started intensively in the summer of 2005. The surety that we were going to have a capacity shortfall flowed a great deal from the adoption of the capacity planning criteria change, which the Board of Directors examined and reviewed in a series of workshops, along with some of the preliminary thinking of this Resource Plan, over the fall of that year, in October and November, if I am not mistaken, and following into the final meeting in December.

So when we started off, there was not a capacity shortfall in front of us, and there wasn't an energy shortfall. There was a long-term issue of how to balance any possible industrial loads and some other things. And the Carmacks-Stewart project emerged that fall as a government-funded project option, which they were going to fund the first phase of. The world looks different today than it did then, is my first point.

Secondly, those that went through the '92 experience, I would say, perhaps in a bias sense, what we learned about the issues that arose in looking carefully at the downstream flooding problems, and listening to the testimony that was given by some experts in that hearing, did not make it an option that came roaring to the top of

anybody's head to put your -- to put at the top of the pile.

Marsh Lake took a while to talk about, and we see how sustainable that idea was, given controversy around anything happening in Marsh Lake. There are serious risks, high likelihood

without planning, that you would cause flooding. That is a certainty. The question is, can you build berms, can you study it more carefully, over a period of time, in order to take it on.

I suspect that the planning process we have gone through has led us to think more seriously about that, about one year later, about the middle of 2006 versus the middle of 2005. Ideally, I agree completely. In hindsight, if we knew all that we knew right now, I would say I would have loved to have thought of it more clearly back then. I give the process credit, the people we talk to, the people bringing up the ideas, and pursuing it. There is no great mystery about it. It is a very difficult option to pursue, it has not got a big pay-off. It has a lot of potential controversy and problems with it. But nonetheless, the Corporation has committed themselves to hiring very good people to look at it seriously and go about doing it seriously. Because if it is does

work, if it is cost-effective to spend some money

on the mitigation measures, we do get -- as you just said, we get 2, 3, whatever it is, megawatts of extra winter capacity, not energy, but capacity, without using diesels.

Q It sounds like, from what you said, Mr. Osler, that perhaps the decision to not proceed with looking at this project sooner is due, at least either largely or in part, to the controversy -- potential controversy surrounding it.

A An engineer describes it as technical issues, and the technical studies needed. I am describing it as an non-engineer who took part in the '92 hearing, so did Mr. Campbell. I remember it as technical issues that had some scary overtones for a corporation that is a Crown corporation, or any other type of utility, in Whitehorse. And in order to study and come forward with it as a proposal, you better have some answers to the questions that nobody had answers to back then.

When we went back and reviewed the 1995 study carefully, we saw some recommendations as to the type of courses of action that could be pursued, which were the studies that were carried out after the 1992 hearing.

Q So it had some scary possibilities to it, as you

stated, or overtones, but isn't that exactly the point of the study, to see whether you can address those factors?

A I think, in the end, that is my point, is that the Corporation has come to do it. Ideally, I think there is not much sense arguing, if we had thought through it, would we have put it more front and centre in the thought process in the fall of 2005, even if we didn't get around to doing it. We probably would have, and I do not have any problem agreeing with that proposition. I know that I did not get -- if you want to be personal about it, even though I was there before, I did not get around to reviewing it and revisiting it until about the middle of 2006, in response to comments that people say, well, what about this, what about that.

I do not think a lot has been lost by the six to nine months difference between when we could have potentially first thought about it, and the time that we finally got on with it, in terms of reality. But I give you your point. If you think that we could have thought about it a bit sooner, and put it in the additional plan in January, I do not think it is a proposition that we can argue

against you successfully on.

Q I think I have just have one more question on this area. Mr. Campbell, I believe the Acres Engineering study indicated that capacity, winter capacity, could potentially get to 29 megawatts under this. In your view, is there the potential for greater than 29 megawatts?

A MR. CAMPBELL: I think that would be extremely unlikely. Part of the issue is, there are two concerns with regard to ice management, and the first concern is when the ice is forming in the low lying areas, particularly in the Marwell area in Whitehorse. As the ice front builds in the early part of the winter -- well, I guess it is not that early in terms of the wintertime, because it occurs in December up here. As it builds past the Marwell area, it is a known area that floods every -- Wayne, maybe every second year? In fact, we have had -- we did install a water gauging station in the area in about 2000, in order to work with the City, to better understand what occurs when the ice formation is appearing in that low lying area,

and that will always be somewhat of a constraint. And again, part of the purpose of the study is to identify, are there some ways to mitigate that during the ice formation period, and then the second part, of course, is to deal with how much

can we vary the flows on a daily basis once the ice has been set at that level. Past 29 megawatts ... actually no, I do not think we would be able to achieve more than that.

Part of the problem with daily flow variation, of course, you have to rebuild it. If you are going to draw it out at a higher rate, you have to build it back up at some part of the day or night, and there will always be a limit to how much you can scour the underside of the ice to increase the flow on a daily basis. So I think that would be -- it is a pretty practical limit, in our minds.

Q Do you think there would be the potential for greater than 29 on a peaking basis, like just to meet -- I should say in an emergency situation, if you have -- let's say the Aishihik transmission

line goes down?

A Yes.

Q Do you think there would be the potential for greater than 29 on a very short -- or over a short time period?

A No. In fact, it may well be the opposite, because a sudden release of water is more than likely to over-top the ice front, and you would have over-ice flooding which, in fact, we did see some of that during the upset that occurred on January the 29th,

where all of the units tripped off, so there was very low flow for a while. By the time the units had power back to open up the spillway gates, they had to open up a higher than normal amount of water in order to lower the water in Schwatka Lake. That higher flow of water, for a very short period of time, was enough to release shore ice, and caused part of the ice jam that occurred in the Robert Campbell Bridge area. So I would say no, it would be even more of a concern in a short term, because it is the short-term sudden slug of water that is most likely to cause the problem. A gradual

increase is more likely.

Q Thank you.

Dr. Billinton, I will turn to you now. I do not think you need to turn up this reference, I will just mention it to you. In the YEC's overview, Section 3.3.1, they state that the LOLE function is an average, and that it doesn't indicate how long any particular outage will last, or the potential severity of the consequences for customers, and then they appear to suggest that this is the reason why the N-1 is used in parallel with the LOLE.

Now, the N-1 criteria, that doesn't give you any information about the duration of a potential

outage, correct?

A DR. BILLINTON: The N-1 criterion is relatively straightforward. Basically, the system should be able to withstand the loss of any single element. It is a little dangerous, then, to try and build any more into that than what is actually there. That is what it does.

Q Okay. With regard to the LOLE, that tells you the expected number of hours per year when the energy sources may not be adequate to supply the load. Is that fair?

A Yes. The loss of load expectation is the long-run average number of hours in a year when the load will exceed the available generating capacity. We should not mix the word "energy" sources in there, we should talk about "power" sources, because we are really looking at the instantaneous power that is available at that particular point in time.

You should also realize that, with an expected value, of course there is an underlying annual distribution of the loss of load, and there will be some years, hopefully, because the loss of load expectation is a relatively small number, there would be a large number of years in which there will be no situation such as that. The distribution is actually hyperexponential. There

is also the possibility that there will be some years when the loss of load is much greater than the average value. But that's where it is; it is a

duration index. You cannot ascribe properties to this indices or to the N-1 that they do not have. That is just wishful thinking. What it is, is simply a measure of the expected number of hours in the year when the load will exceed the available generating capacity.

Q So it doesn't really tell you how long you can expect any particular outage to last?

A No, it doesn't contain a frequency component, it doesn't contain an average duration component, it is the expected value of what could be a group of incidents.

Q Now, the loss of, what is it, expected energy, the LOEE, does that tell you more, in terms of the duration of a potential outage?

A No, it doesn't tell you anything about the duration. It tells you a blended composite of frequency duration and impact into an index that translates into the expected energy not supplied. And you cannot -- and again, you cannot give it properties it doesn't have either. That is basically what it does.

Q Okay. Now, on the first day, you indicated that,

in your view, the LOLE and LOEE are both good indices?

A They are certainly both good indices, right.

Q But you have recommended the LOLE because it is used more widely?

A It is certainly used more widely. If I could just take you to that table in the report, which is YUB-1-1, where our report is filed. If you look at page 7 of our report -- sorry, page 7 of 60 in that report, and I think it is worthwhile just taking a moment and looking at that report, because it alludes to, or it indicates, the jurisdictions that do use the LOLE. It also talks about their criterion, and it may provide us, I think, with the opportunity to dispel some myths with respect to what some of these indices really are. If you have that in front of you, if you look -- Madam Chair, is that okay?

THE CHAIR: The reference is YUB-1-1?

A Yes.

THE CHAIR: Thank you.

A If you look at that table, the first one you see is British Columbia Hydro and Power Authority use the loss of load expectation. And you note that they talk about one day in ten years. Now, that doesn't

seem to link to any of the indices that we have talked about. But they use a load model which represents the day by its peak value, so that is how they start out. Then they calculate the loss of load expectation in exactly the same way we have done, and they come out with an index of .1 days per year.

Now, for communication purposes, they decided that it is not so good, perhaps, talking about fractional days, so they take the reciprocal of that and they make it one day in ten years, and that is the index that you very often here tossed out in various jurisdictions, one day in ten years.

Now, that is an entire misnomer because that has a frequency connotation to it that says this is going to happen once in ten years, and that is not true. So that index is exactly the same kind of index that we are talking about, but expressed in a different way.

You look at the next index, Alberta Interconnected System ... now, prior to them doing

a study, which I am sure your consultants on the Board know far more about than I do, but I did happen to participate in it, they used an index of .2 days per year, which says, when you compare

it with the B.C. one, they were prepared to accept a lower reliability because they are prepared to accept a higher risk as their criterion, so .2 days per year. So right off the bat, you can see that those two utilities use the same methodology, essentially, that we are talking about, but do have slightly different indices because their management have perceived that those are acceptable indices for their particular system.

Now, we look at the next one, Saskatchewan Power Corporation, and, at first glance, you might have considerable difficulty relating to that. That is expected unserved energy, and that comes to the point, I think, that you are referring to, with respect to the expected energy not supplied. And here they use 200 upm. What is a upm? It is a unit per million.

See, the difficulty with the energy index is

that, as your system grows, the amount of expected unserved energy will increase, only because your system is growing. So, therefore, you have to find some way of normalizing that so that you can have an index which can be used over time as your system changes size. So therefore, Saskatchewan Power Corporation decided to normalize the unserved energy by dividing it by the total amount of energy

that the system requires in the year. So I note here, you divide megawatt hours by megawatt hours, and you have a dimensionless number.

Now, in their particular case, that number turned out to be .0002, and nobody wants to talk about that many zeros. You cannot have a discussion with anybody about what is the difference between three zeros 2, three zeros 199. So what they decided to do is multiply by a million, which then makes it into 200 units per million, only to get rid of all of those zeros. So you see, that was a normalizing effect that they have to do with the expected energy index in order

to arrive with a number that is discussable.

Manitoba Hydro used .1 days per year. If we go to the next one, Ontario Hydro, you will see that they use expected unserved energy, but they decided that they are going to normalize it in a somewhat different way, so they divided the expected not supplied, whose units are megawatt hours per year, by the system peak. Now, loosely, now, you can divided megawatt hours by megawatts, and you will get hours. If I multiply it by 60, I will get minutes, so I will call that system minutes. So their criterion was 25 system minutes. Again, it is an attempt to normalize it

so that they could use it on a continuous basis as their system changed size, and also, hopefully, you might compare it with somebody else, but unfortunately, nobody else does that so, therefore, it makes it very difficult to compare. And you will see that the remaining utilities in there use the loss of load expectation.

So the loss of load expectation is an index, which, when you see it, I think it is more

understandable and observable than system minutes and upm. Those minutes, by the way, system minutes, are not real minutes, they are actually the minutes at the time of system peak which, if the system had an outage, would result in the same expected energy loss as the calculated value through a probabilistic analysis. I don't want to belabour this, but if you really want to explain that to somebody, you are going to probably have to do it several times to get your point across.

So it is an index which, from my point of view, is a good index, but which is not the kind of index that you might want to put before a Board, or before the public, or before the government, with respect to understanding. And the loss of load expectation index is a very useful and a very straightforward one.

I just took the liberty, too, I would just like to quote to you what -- if I can find it -- I am not as organized as some people in our group here. I took the liberty of just copying down just

what the index is, used by one of the largest power groups in North America, and that is the Pennsylvania-New Jersey-Maryland interconnection, which is part of the NERC grid, and I will just read you the first portion of their criteria:

> "Sufficient megawatt generating capacity should be installed to ensure that, in each year, for the MAC system (and I will indicate that in a minute), the probability of occurrence of load exceeding the available generating capacity shall not be greater, on the average, than one day in ten years."

They are using the loss of load expectation approach, and that is pretty well prevalent right through the United States couple through the NERC grid system. BGM have about 75,000 megawatts of capacity.

I just wanted to show you the other end of the spectrum from the system that we are dealing with. We are talking about a very large system which uses the loss of load expectation technique.

So I think, and I tried to make this point yesterday in response to Mr. Landry, I think the loss of load expectation technique is a sufficient technique. It does what is needed to be done with respect to providing a valid indication of generating capacity adequacy on an overall particular sense, and that really is, I think, my answer to your question.

Q I think that might go down as the longest answer I have ever had to one of my questions, but it was helpful.

Just to follow up a couple of points ... so I can certainly see how the loss of load expectation is easier to explain and communicate to the general public, et cetera. From your strictly engineering point of view, setting aside the ease of understanding by the general public, which do you think is a better indice? Like, which tells you more, which is more helpful, the loss of load expectation, or the LOEE?

A Well, I think, in a general sense, and we have done studies in the past to look at capacity expansion, and, striking a base value in each particular case, you would finish up pretty much with the same sequence of capacity additions. Because what happens when you do capacity planning,

notwithstanding the range of things that have been looked at here, but just, let's say, more conventional capacity planning, the index would provide a trigger for the need to inject some capacity in there for some money into the system, and in either case, I think they would, starting from an equivalent point, they would inject the same signals into the system. So from that particular point of view, there is nothing to choose between them, in that particular case.

Now, if you want to do -- if you wanted to know the expected energy not supplied, if you are asking me, will I get that from the loss of load expectation, the answer is no. If I want to do something different, then obviously that is what I need to do.

Q So from that perspective, is there some benefit to having the LOEE criteria, over the LOLE, because it can tell you that information?

A If there is some direction that you wish to pursue, in which the expected energy not supplied, and the annual energy not supplied, and the distribution that is associated with it, serves some particular purpose.

Q And do you think there is some value to having that information?

A Well, studies have been done, right. I think I know where you are leading. Studies have been done to look at the -- to look at the cost of unserved energy, from a customer perspective, and to incorporate that in the evaluation. And if that is a direction that you wish to go in, then you obviously cannot get there with the loss of load expectation.

But if you wish to do basic and conventional generating capacity planning, by the way, as all those utilities have indicated they do, including the designation of load serving entities, and the allocation of capacity responsibilities to organizations within a big region, then the loss of load expectation is being used in those particular purposes.

So, again, it is like you asking me, if I want to take a screw out, is a hammer any good? No, it is all right for putting a screw in, it is not

recommended, but it is not a very good way for taking one out. A screwdriver is a lot better. So you have got to decide what you want to do, and then proceed, if that is the case, use the right tool.

Q It seems that the sense I get is that, okay, all these other jurisdictions use the loss of load

expectation, so why do we not do it, too?

A Well, you would have to tell me why not, if it is what I want to do. If I want to determine, is my generating capacity adequate, and this is a valid measure, and in my opinion it is a valid measure of adequacy of capacity, I think it is just a certain amount of reassurance that, by golly, all these other people use it, and are happy with it, and make decisions based upon it. So, again, it is a question of what you want to do. And my perception is, from the task that we were assigned in respect to looking at the probabilistic applications, this is what the Corporation wishes to do, and this will certainly, in my opinion, do just that.

Q So, if I understand it correctly, they are both

good indices, they will both help you plan the system adequately; the benefit to choosing the LOLE is that it is simpler, it is used widely, it doesn't necessarily tell you as much information, but it is a simpler indice that does the job?

A It does the job, and it is also possible, I believe, to benchmark it against the index, the same index, methodologically, that other utilities use and, therefore, determine whether you are in the same ballpark.

There is also one other reason, which maybe

you don't perceive to be a good reason, but it was accepted right next door in the neighbouring territory as the approach, and, therefore, it does provide some measure of comparison also, then, with the degree of generation adequacy that has been incorporated in planning in the Northwest Territories. I just put that in as the last comment because that should not be a driver in itself, but it is certainly a very important factor, and it is a fact. And it was discussed,

and some of the discussion there was similar to what we are having now, before this Board, before that Board, because I participated in that discussion, too.

Q I was actually going to ask you about the Northwest Territories, and your involvement there. In that proceeding, did you look at both the LOLE and LOEE?

A In early studies, we did, we did talk about it.

Q And what was your -- was your recommendation for adoption of the LOLE?

A If I recollect, now, our first studies were done way back. I think we really, initially, only looked at LOLE in order to open the door for discussion of probabilistic methodologies, because they were wedded totally to the deterministic

approach. And then we did discuss it. I think there wasn't any tremendous interest in applying it, the LOEE technique, in that particular case.

Q Okay.

THE CHAIR: Ms. Marx, I note that we are coming up to the time we said we would

break. Would this be an appropriate time in your line of questioning?

MS. MARX: Yes, I think that is fine.

THE CHAIR: Okay. We will take a 15-minute break and reconvene about 25 after. Is that 15 minutes? Everybody tells me everybody's watch is a bit different here. 20 after?

(Proceedings adjourned at 2:10 p.m.)

(Proceedings resumed at 2:30 p.m.)

THE CHAIR: Ms. Marx, are you prepared to proceed?

MS. MARX: Yes, thank you.

Q MS. MARX: Dr. Billinton, I am going to do my best to still get us out of here at four o'clock, and finish all of my questions for you. It may require me to do a little jumping around in my questions, it may seem a little disjointed at times, but I would like to try to finish off all the questions I have for you. There

will be a few for YEC mixed in, in the mix here.

A DR. BILLINTON: Thank you.

Q We will see what we can do.

I would like to talk about the, just generally, I guess I could put it the benefits, perhaps, of the probabilistic versus deterministic criteria.

Now, with the LOLE looking at every hour of the year, so essentially all peak loads, that makes the criteria sensitive to the shape of the load. Is that fair?

A That is fair.

Q And the deterministic criteria would be oblivious to that?

A Well, it would be oblivious to what you choose not to look at from a deterministic point of view. In general, then, it is -- the deterministic criterion is usually related to the peak load.

Q Right, and so it is just the annual peak that it is looking at?

A Annual peak. But it could be monthly peaks, but you are right, not being argumentative, it is basically applied to a particular load level.

Q Right. And I think it is fair to say that the move to a probabilistic criteria is a positive step forward for YEC. Would you --

A Perhaps this might be a good time just to comment on the original deterministic criterion. That criterion incorporated a couple of factors, and that was the largest unit, and then it added a component of diesel capacity. And that criterion, I guess, was perceived to be acceptable and adequate at the time at which it was created. But it is not responsive to changes in the system, in the system parameters, it is inflexible, and therefore, it does not respond to the actual factors that influence their reliability, such as the hydro units in general happen to be more reliable than diesel units -- or, let's not pick on diesel ... on fossil units, or on nuclear units. That deterministic criterion does not respond to those kind of conditions. And going back to your earlier point, it doesn't respond to the shape of the load.

If you had an annual load factor of 90 percent, or an annual load factor of 60 percent, which means, of course, the load is a lot peakier and drops off, then the deterministic criterion would not see that at all. So, therefore, deterministic criteria, in general, are not responsive to the actual factors that influence

their reliability.

So to go back to your question, yes, the probabilistic approach incorporates all of those, or can incorporate all of those and, therefore, gives you a more responsive index and, therefore, a better measure of opportunities that you are proposing in connection with expansion plans are properly evaluated.

Q And I think you said this, but just to confirm in, sort of, my simple language, the LOLE is sensitive to each generator's failure rate, their unique failure rate?

A The LOLE -- not the failure rate, the unavailability. The failure rate is the frequency of unit failure. The loss of load expectation utilizes the unavailability of the unit, which is the probability of finding that unit on outage at some particular time in the future. So it is not the failure rate, it is not the duration of outage of a generator, it is actually the two put together, which gives you the probability of that unit being unavailable. That is what it is

responsive to, and the size of the unit. The size of the unit, and its unavailability, it responds to that.

Q Sorry, can I get you to run over that again. The LOLE would give you the probability of outage of a

generator?

A No, this is input.

Q Okay.

A We are talking about input LOLE.

Q Okay, okay. So, essentially, the probabilistic criteria tells you more than the deterministic. It responds to a greater number of factors?

A The deterministic is a go/no-go.

Q Right.

A It says if I do not meet that, then -- it is not a measure of risk, it is not a measure of how often, or the likelihood. It is simply a bar that simply indicates above is acceptable, and below is unacceptable, or vice versa.

Q Okay. And if you have the probabilistic criteria in place, in your view, just briefly, what is the

justification for having a deterministic criteria as well?

A Well, the justification for the deterministic criteria is with respect to particular incidents, and the severity of those incidents as recognized by the particular system you are dealing with, and the topology of that system. And I presume, of course, you are leading towards why would we want to have a probabilistic index and a deterministic index as a dual criteria in the case of the

Corporation. Is that the direction?

Q Sure.

A Yes. So when you look at the probabilistic approach, you get the overall assessment, you get the overall assessment of the adequacy of the system, in terms of its ability to meet the total system load, but generating capacity adequacy assessment deals with the ability of the total generating capacity to meet the load requirement, and it is not focused on any one particular portion of the system.

Now, when you look at most systems, the

generating capacity adequacy does not, in itself, normally incorporate transmission facilities, because the transmission is usually redundant. I don't know of very many systems, perhaps other than next door, in which you finish up with a large amount of your capacity on the end of one transmission line, a single transmission line. Therefore, that system is particularly vulnerable to the outage of that particular facility. And it becomes obvious, when we started to do our probabilistic assessment, that the indices were very much affected by the transmission line between Aishihik and Whitehorse.

So when you look at that, and you see the

vulnerability that is associated with it, and you think of the criteria that are very often used in conventional planning, even in those utilities which use adequacy assessment using probabilistic approaches, and that is the N-1 criterion, which is embedded within the NERC, the North American Electric Reliability Council, criteria with respect

to system planning, then you see that the N-1 criterion is an important criterion, and particularly important in this particular case, because the loss of that line has immediate and drastic consequences upon the continuity of supply at Whitehorse.

So, therefore, there is a need for, I think in that particular case, to recognize that vulnerability, and I think it was driven home, as I said yesterday, very dramatically on January 29th last year, and that was the loss of that line. So the N-1 criterion is immediate, it is a non-probabilistic index. It says the system should be able to withstand the loss of any single element, whether that element is a generator, a transmission line or a transformer. In fact, those are the conditions that are outlined in the NERC standard under Condition B, the three conditions that should be satisfied.

So there is precedence again for that. And I think, in this particular case, because of the topology of the system, because of the topology of

the system, then it has an immediate and a drastic effect with respect to the adequacy at the Whitehorse bus, which is the largest component, the largest load component, in this particular system.

Q And given what you have said about the Aishihik line being the most vulnerable component, essentially, of the system, would it not make sense, under the N-1 criteria, to focus on that, on finding a solution there, instead of -- what I am getting at is, instead of increasing capacity in other -- at other places on the system, would it not make sense to then focus on remedying that weak link in the system, for example, by twinning the Aishihik line?

A Now we are moving away from the justification, from an N-1, for a dual criterion, and decisions that might be made on the basis of having a dual criterion.

Q Yes.

A My task, by the way, was not to look at system planning for YEC. My task was to look at -- initially, it was to do a probabilistic assessment, and provide the recognition of what are the

pertinent factors, and then we held a workshop up here, at which time we discussed all of these things, compared it with what was happening in Northwest Territories, and then proceeded to determine the criterion.

Now, having gotten the criterion, now we come to -- you are asking me now, what would I do under those conditions, then, to plan the system. And you are right. If you were to put another line in, coming in from Aishihik into Takhini, now I apply the N-1 criterion, what would be my immediate effect? Now, you see the condition is different, right? I am not losing 30 megawatts, I am potentially losing 30 megawatts at Aishihik, I would be in a quite different situation. So you are right, it will have an effect. But once you have established the criteria, then, I believe, you are free to look at the alternatives, and the alternatives have been, not a host, but a group of alternatives have been put before the Board today as potential actions that are going to take place, could take place, in this particular system, and the criterion would then determine whether they meet certain requirements, and whether they are adequate in terms of moving forward.

Q Am I correct to say that you did not recommend, on

your own, the N-1 criteria, but, to put it simply, perhaps you did not see a big problem with YEC adopting that, or you thought that was acceptable?

A I do not think it was -- I would like to think it was nice and clear-cut as that. But what we had was a really good workshop here, in July I guess, of last year. We came with our report, we made our presentation with our report, with respect to benchmarking the loss of load expectation index. We then discussed the Northwest Territories situation, we discussed the similarity and impact of a line failure on Yellowknife and a line failure upon Whitehorse, and I guess, through discussion, we gravitated to the fact that the existing deterministic criteria could not be modified and extended to meet the requirements. A probabilistic requirement was required, but, because of the vulnerability of Whitehorse, that the N-1 criterion was a good criterion that should be added to form a dual situation.

I do not think -- I think you would be quite wrong to say that I suggested it, or I went along

with it. We just had a really good discussion, and I think sort of arrived at that particular position on a collective basis.

Q And in the Northwest Territories, that we discussed

earlier, they have the LOLE and N-1, correct?

A That is right, correct.

Q And in that case, did you recommend the use of N-1 criteria?

A I think that came out of a series, as I said, we -- the situation there was somewhat peculiar in that they decided, and I do not know the right regulatory terms, perhaps our counsel can correct me, but I think we had some conciliation meetings between the intervenors, in an attempt to forestall some difficulties that arose before we ever got to the hearing. I am not sure just what the appropriate term is for those, and -- but we couldn't. We couldn't arrive at -- the intervenors decided they did not like certain things, and they were not about to back down on those particular conditions. So then we finished up with many discussions, which led us to a position that the

Corporation, that is the Northwest Territories Power Corporation, accepted, and those are the ones I put forward. And I think it is difficult to say that, yes, this was a recommendation. It was, again, a joint decision, and a joint discussion, with the utility and with myself, over, I might add, about an eight-year period. But we did arrive at that conclusion at the end.

Q Sorry, I am just trying to find a reference here.

In YEC's Resource Plan, on page 4-9, there is a chart there that is entitled "WAF Base Case Capacity Requirements". And I am not sure you need to turn it up, Dr. Billinton, but what it shows is, over the period of the 20-Year Resource Plan, and also beyond, but if I focus on the period over the 20-Year Resource Plan, the N-1 requirement is consistently higher than the LOLE requirement.

Now, I assume that would be the case as long as we assume that, under the N-1 criteria, the worst-case scenario is the Aishihik transmission line going down. If we assume that, I think it is

always going to -- it is going to stay that the N-1 requirement is higher than the LOLE.

So my question to you is, given that, what would be the justification to -- if we went with the N-1 criteria, what would be the point of having the LOLE criteria, then?

A I just conferred with Mr. Bowman with respect to what YEC's intent was in that particular graph, and I think it is better that he explain the intent behind that graph.

But when you look at the two criteria, and let's just go back on a more philosophical approach, the location of the capacity would have a

considerable impact with respect to what would be the drivers with respect to the largest contingency. And when you start looking at having capacity at the Whitehorse bus, then, of course, this is going to change the demographics quite considerably with respect to where the impact of an N-1 outage would be. And it would not be true, I do not think, when you start thinking of the location of the capacity injections, that the N-1

would always be, would always be -- let's say, override the loss of load expectation.

So I think in this particular case, perhaps, with the plans and the things that have been put forward, perhaps it fits that particular mold, but I don't believe it is correct to say that that would always be the case, because the location of the capacity with respect to the existing topology of the network will have a big impact upon whether that particular event is the most serious.

Q But if that is the most serious event over the period covered by the Resource Plan, essentially, does it make the LOLE redundant over that period?

A No, no. Because the LOLE gives you a measure, a probabilistic measure, of the expected number of hours in a year that you are going to be in difficulty, keeping in mind that deterministic

criterion does not provide you with any -- as I said before, it is a harsh measure. There is no soft edge to the deterministic criterion, it either meets it, or it doesn't meet it. It doesn't give

you any indication of the risk level, the probabilistic indicator with respect to the likelihood, or that particular portion of it, and, therefore, it provides just a go/no-go situation.

Q But essentially -- if I can just ask one more question of Dr. Billinton, and then you can provide your explanation, Mr. Bowman.

A MR. BOWMAN: Why, yes.

Q And I have lost my train of thought now.

A DR. BILLINTON: I thought that only happened to me, by the way.

Q Maybe it is contagious.

If you have the N-1, in this scenario, always having a higher requirement for capacity than the LOLE would, essentially, would you even need to undertake the LOLE calculations? Like, once you have adopted the N-1 under this scenario, and the Aishihik line being the worst case scenario --

A But you are saying you know the answer before you look at the problem.

Q I think once -- if you have this chart that shows that the N-1 is always going to be greater, I think

you would not need to keep doing the calculations every year for the next 20 years.

A Well, you have to think about system planning in a somewhat different way. Here, the Corporation has laid out a bunch of alternatives. Normally, you do system planning, and looking at a ten-year plan on an annual basis and, therefore, you look forward into the future, not necessarily with the objective of accomplishing everything that is in that particular plan, but with the objective of making the next decision, the correct next decision.

So, therefore, there is not that much certainty, with respect to looking way off into the future, that you are going to accomplish everything that you have put in your plan, because there is a considerable uncertainly associated with the future.

So as you march off, you make the next decision, and then you update your plan, and then you proceed to look at what you have already done, which has now become a fact, and then you proceed to look off in the future from that particular point. And there, the dual criteria, I think, would stand you in good stead because you could not say the N-1 will always prevail. You are drawing a conclusion, I think, from that particular diagram,

not necessarily from the idea of having two criteria, which would lead you to making the next correct decision.

Q Mr. Bowman, was there something you wanted to add with respect to that table?

A MR. BOWMAN: I just wanted to help, what may be -- and may not be -- but may be a misunderstanding in the premise for the question. The graph you have turned to is the simple WAF base case forecast, and that is at page 4-9. And it would show that in a base case forecast, where you have no industrial loads, the N-1 would, indeed, be the driving factor throughout the period of the Plan. There is one key difference, though, between the LOLE and the N-1 as proposed, as reviewed by Yukon Energy, and as ultimately adopted, which is the LOLE criteria reflects an overall balance on the system to ensure reliable power can be provided throughout the year.

The N-1 is an emergency or back-up criteria related to those loads that do not have their own back-up. The practical difference is that, when you are calculating the LOLE, you include the load of industrial customers. When you are calculating

the N-1, you do not include the load of industrial customers.

So if you look at that same graph, the same model, but four pages further in the document at page 4-12, it will show the same graph but with those lines in the case where we have added Minto and Carmacks Copper mine, and you will see that, in that situation, within the 20-Year Resource Planning period (sorry, this is page 4-12), within the Resource Planning period, the LOLE becomes the dominant criteria driving the system during the life of that mine. So it is a relevant criteria for the period of the 20-Year Resource Plan.

And the other relevant consideration is that two criteria, together, are intended to be robust and not have to be redesigned should the system topology change. The concept of an N-1 criteria relating to those loads who do not have their own backup, and an LOLE relating to the entire system loads, is intended to be durable whether we build a second line or not, or whether other

interconnections occur.

And to the extent that people would want to turn to it, the graphs start to get a little bit more complicated, but at page 4-36, the situation with an Aishihik second transmission line is shown. And in that case, you can still apply the same two criteria. You can still apply them during

the planning period, and they are relevant to the overall plan, and they would show the N-1 criteria dropping quite dramatically because you are no longer exposed to the 30 megawatt risk. The LOLE criteria drops somewhat for the same reason, but not nearly as much as the N-1. So, in fact, the LOLE is slightly above the N-1 criteria there, and that is before any mines are added. Were there to be a second line and mines, the LOLE would be quite a dominant driving characteristic. So the idea of proposing two during the 20-year period was that they would be robust and they would be able to deal with these different contingencies.

Q All right. I may come back to that later, or tomorrow, but for now I will continue with some

questions for Dr. Billinton.

Could you turn to Figure 2.4 in your report, Dr. Billinton. I have it in the attachment to YUB-YEC-1-1, page 15 of 60.

A DR. BILLINTON: Right.

Q And this figure is entitled "Summer and Winter Load Models for the WAF System".

From what I understand, these are normalized load duration curves derived from actual historical load records; is that correct?

A That is correct.

Q And the 1.0 on the Y axis represents the peak in summer and winter; is that correct?

A That is per unit of the peak value, yes.

Q And as I move to the right on this table, which represents time, I see that both curves fall, quite quickly, to about less than .9, around .9 percent of the peak.

A Right.

Q Now, am I correct to assume from that, that the load is at or above .9 of the peak only for a very

short period of time?

A That is true. In most systems, that is the case.

Q All right. Sorry, I am just trying to juggle my questions here.

Now, if I could get you to turn to Table 3.5 of the Resource Plan, and this is at page 3-24. And if we look at the N-1 criteria, the columns on the right side of that table, in the column "Peak Excluding Haines Junction", if we look there, given that the load -- the load is only at or above .9 of the peak for a very short time -- sorry, just a moment.

So, under the N-1, would it be appropriate to be looking only at the peak, or at a broader section, like times other than the peak, given that the peak only occurs for that very short time?

A Now I think you are talking about kind of a modified N-1 criterion, in which you are going to mix the probabilistic likelihood of the load exceeding a particular situation. And the N-1 criterion, as it is applied, is applied to the peak load level. So you can certainly do just what you

have suggested, but what you are doing now is modifying the standard deterministic criterion.

The criterion, as is stated, by the way, as used in NERC, is that the interconnected transmission system is planned such that the network can be operated to supply projected customer demands and projected firm transmission services at all demand levels over the range of forecasted system demands. So it does not include a probabilistic interpretation of what the load would be and how long that load would exist. So you certainly can do what you are suggesting. You can certainly look at the number of hours at which that would result, but that would not be the N-1 criterion.

Q So in my simplified terms, the N-1 is, I guess, a simple criteria, looks at the peak, looks at the worst-case outage that would happen on the system, it is quite simple from that perspective, but I think it is also probably quite pessimistic. The

likelihood of that happening is probably quite

slim. Is that fair?

A Right. As I said earlier, the deterministic criterion is a hard criterion. It does not have any edge to it with respect to the likelihood of the event occurring. It simply says this condition -- can the system withstand this particular condition at the time of system peak?

Q So would you say that the LOLE criteria is more realistic?

A No, it is more responsive, and it gives you an entirely different perception of your system. And we believe, in this particular case, that accepting the two then provides protection with respect to the vulnerability of Whitehorse to that particular event, and also provides an overall assessment of the system, the second part of course coming from the LOLE.

Q Now, if I look at the middle column under the N-1 criteria, which is N-1 criteria load carrying capability, and I look at the first figure for 2005, of 55.7, this is -- am I correct that that is the sum of all available generating capacity in winter, excluding the generators that would be out if the Aishihik line was out?

A I think that comes from 87 minus 30 minus 1.3. Is

that right? The 30 comes from Aishihik. The 1.3 comes from Haines Junction.

Q Okay. Now, Dr. Billinton, what was the probability of outage that you used for the Aishihik transmission line? Was that .66 percent?

A Right. And if you look in the appendix to the report -- which I will find the right page -- page 58 of 60, in that YUB-YEC-1-1, the unavailability of that line was taken to be .006639 or .6639 percent.

Q Okay, thank you. So under the N-1 then, the assumption is that it is at peak load, and it is an outage of the Aishihik transmission line, but the probability of that happening is only .66 percent?

A The probability of being in that particular state is .6 percent.

Q And if I look at the peak, again in that same column of Table 3.5, the peak of 55.4 for 2005, Mr. Bowman, that is the annual peak that you would expect likely during the November 2005 to March 2006 winter period; is that correct?

A MR. BOWMAN: Actually, I believe Mr. Campbell dealt with this this morning, but that is based off of the numbers to the farther left of the table, of 56.4, which was an actual peak, and

26 the date and time of that were given. I believe it

1 was in January 2005.
2 Q Right. But generally the peak is going to occur
3 between November and March?
4 A It occurs in the winter months.
5 Q Okay. Now, according to this table, under the N-1
6 criteria, YEC actually had a surplus, it shows a
7 surplus of .3 for that period. Yet that is the
8 period where there was the outage -- the failure of
9 the Aishihik transmission line. So what I am
10 trying to understand is how the N-1 would have
11 helped you there, because that outage occurred even
12 though you are showing a surplus for that period.
13 A And you are showing a much larger surplus under the
14 LOLE criteria. But this was reviewed in some
15 detail in a filing with the Board on April 11th,
16 2006, about the outage response and what occurred
17 with YEC's system. It goes to, I guess, your
18 comment earlier, that the N-1 criteria may seem
19 very pessimistic to some because it assumes the
20 Aishihik line fails at peak. The N-1 seems very
21 optimistic to others because it assumes everything

else works at that particular point in time. Everything else on the system has to be working the way it is supposed to. And as this response goes through at that particular point in time, there were some other issues that had to be worked

through, which is what led to the outage. It would not lead to additional capacity on the system. It would not have led to additional capacity on the system as of January 29th, 2006.

Q Could I get you to turn to YUB-YEC-2-11, page 5 of 7. And if I look at the first table, Table 1, LOLE Calculations, there is a column there entitled "Aishihik Third Turbine 2009", and it shows down that column, in 2009, that there would be, it says 7.0. And that is the capacity of the third turbine, 7 megawatts. Is that correct?

A That is correct.

Q Now, it appears that, to get the shortfall, what you have done is taken the LOLE calculation and just added the 7 megawatts to that, in addition -- I realize there are three numbers under the

project's heading, so it looks like you took the LOLE shortfall and then took into account the 1.6 for the Marsh Lake project, 8.0 for the Aishihik second transmission line, and the 7.0. Is that correct?

A I take it you are looking at the top left-hand part of this table, where there are sort of multiple tables on the page.

Q Yes, Table 1.

A And this question was asking for a particular

scenario that said, assuming that you build Marsh fall/winter storage and the Aishihik second transmission line, and then put in place the third turbine, what would be the shortfalls? Just so everyone in the room is following, the top left-hand part of that page calculates the LOLE shortfalls, the bottom left-hand part of that page calculates the N-1 shortfalls, and the right-hand side of that page looks to which one would be the driver in the scenario. And so you can see that, depending on the -- after the line is built, LOLE becomes the driver. But what this is showing is

that if you have the second line built, putting in place the third turbine benefits the system's capacity by 7 megawatts.

Q What I am getting at is how the calculation was done. I just want to confirm that you had the original LOLE calculation, and then you simply added that additional capacity to determine what the shortfall or surplus is?

A That is correct. You take the shortfall and then add the contribution from each of the projects, to get to the resulting WAF system balance.

Q Dr. Billinton, in your view, is that the correct way of determining what the shortage would be? I am wondering whether, in determining that, you

should not just be adding that additional capacity, but that should be factored into the LOLE calculation with outage rates, et cetera.

A DR. BILLINTON: Right. You could add the contribution associated from that particular resource addition. But you are correct in the sense that you would do a study in which you would

add the second transmission line into the configuration, add the appropriate reliability levels, you would add the third unit on the Aishihik bus. You would then proceed to increase the winter capacity level in Whitehorse, by virtue of the reduced constraint associated with the March Lake, and then you would perform the analysis, and you would finish up then with a total picture.

Now, I think if you knew the individual contributions -- see, we have done studies right now, with respect to changing the restriction at Whitehorse, say, from 24 megawatts to 25 megawatts. Well, there is a contribution there, of about 1.1 megawatts, for every change in load carrying capability, as a function of that 1 megawatt change. So you could simply determine the contribution and then have that in that particular way. I am not sure, in this particular case, just exactly how that was done. But it would be the

contribution associated with that asset, to the load carrying capability of the system, and that would come about, or could come about, or it would

be done in one simple study in which you put all of them in there and then proceed to do the analysis.

A MR. BOWMAN: Just to the extent it helps, there is an interrogatory that explains the estimation technique Yukon Energy was using with relation to LOLE, because, at the time these were prepared, it did not have a computer model to do that. Since then a draft computer model has been prepared by Dr. Billinton and his colleague that can now sort of start to try to run some of these, and it has basically confirmed these approaches; that the ratio of the megawatts you add, to the benefit and load carrying capability, is very close to one to one, within the range of projects we are talking about, including this size range.

Q Dr. Billinton, in your calculations, you used CEA industry averages for the outage rates for diesel plants and hydro plants, correct?

A DR. BILLINTON: That is correct.

Q And it is 10 percent for diesel plants and 3 percent for hydro?

A Correct.

Q Now, ideally, wouldn't you use the actual forced

outage rate for each individual unit in the calculations?

A Ideally, you would use the actual data, and I have said many, many times, the best data you can possibly have is your own data, but given a paucity of data, then you have to go elsewhere to get representative values that you would use in the calculation. And the lack of data could come about from not having collected it, or it could come about from having a relatively small data pool from which you might attempt to make some estimations. Your degree of confidence would increase as the population would increase, and therefore you just may not have sufficient data within your own system to arrive at a suitable estimate.

Q Would you expect that, in the not too distant future, that YEC would have sufficient data to make those calculations based on actual data, rather than using industry averages?

A I certainly would hope that they would have sufficient data. If they -- maybe I should not say this, but if they keep having outages with the same frequency, on Line 171, as they have had, pretty soon they will have lots of data to make a good estimate, but hopefully that will not come about.

I would just like to comment, Madam Chair, we

filed our report on February of 2005. After that, you had three outages. I hope you are not going to blame me for the fact that those outages occurred because we drew attention to the vulnerability of Whitehorse because of that event.

But levity aside, going back to your original point, yes, I would. I would think it is important for YEC to collect data and to move towards -- I made that statement in our report, I think you cited it in an IR, and that was responded to. I think they are making steps to report and to record that data in such a way that hopefully they will have sufficient data.

But I would just like to comment, the CEA data, that is representative data, and that is from a broad spectrum of utilities. It is collected in the consistent definitions.

In terms of the transmission line data, I may be wrong here, the CEA report, we produce an annual report, which we use five years rolling average. In connection with 138 kV wood pole H-frame lines, there's 93,000 kilometre years of data in that

particular category. So there is a large population from which that statistic is drawn.

From the hydro unit case, there's 175 units in Canada between -- let's see, in the size category

up to 25 megawatts, and therefore there's a large number units in that particular pool. When you look at the number of units and the number of lines that YEC has, you basically have one or two lines, we might call it, 170 and 171, you have a certain number of kilometres. The population size is not great, and therefore, having confidence in the statistic requires you either have an awful lot of outages, or to collect it for a long time. And, therefore, I think the CEA data is very useful for that particular purpose.

But going back to your original comment, you are correct. The best data you can have is your own data. And therefore I think you need to collect that data under consistent definitions. And I understand from the answer to that interrogatory, I think it is 2.3 or 2-3, that steps are being made to collect that data on a consistent

basis.

Q With respect to the industry average for transmission lines, is there anything, in terms of the characteristics in the Yukon, that would make that outage rate, you know, maybe too high or too low? And what I am thinking of is, you know, in eastern Canada there is the possibility of ice storms, there's tornadoes in other areas of Canada,

things that I do not think you would see here, but I don't know, maybe there are other things you would see here.

A Yes, you are right. Does that data completely represent the terrain over which the lines in the Yukon run? And I don't know the answer to that question. I chair the consultative committee on statistics for CEA. The CEA reports do not reveal the identity of the utilities that provide the data in those reports. Each utility receives its own data back, and it receives the compendium or the totality of data in various classifications, and no utility sees another utility's data, so therefore

the utility is anonymous in that particular sense. But the definitions are on wood pole, there is data collected on cause of outages, there is data collected on the supporting structure, that is why wood pole would be a category of its own, as opposed to steel, or steel guide and so forth. So there's a considerable commonality with respect to that data. But there are differences in isochronic level, which would influence lightning, there is differences, as you mentioned, with respect to weather, but I think the data is representative of the performance of that particular type of line in Canada. So I don't know, I could not tell you

which utilities provided the bulk of that data. I know my own utility, Sask Power, has data, which, when you drive around, you certainly see lots of wood pole lines, so it would be in similar circumstances.

Q Just bear with me for a moment. I think I am doing well. I think I have most of my questions asked of you, Dr. Billinton, good news for you, as you will get to get out of here at 4:00.

A I just hope I have managed to answer them for you.
Q So this means I have to try to figure out where I was before, and go back to that.

Perhaps I can ask a few more questions now about the failure of the Aishihik line in January of 2006.

Now, Mr. Bowman, you were mentioning that there were other problems as well, it wasn't just the line. There were some other additional problems. And I understand that the outage was triggered by the failure of one of the outgoing feeder cables. Is that correct?

A MR. BOWMAN: I would just comment that the -- I made that reference in reference to a report that was filed with the Utility Board here, which is not currently marked as an exhibit. It was filed on April 11th, 2006, and this is

generally discussed, Mr. Campbell can go into more detail, but that is what I was turning to as a reference, if that is helpful.

Q I do not think we need to refer to that report

specifically, just in terms of your general knowledge of what occurred. Perhaps you can tell me, confirm for me, what triggered that outage?

A MR. CAMPBELL: Sure. There was a failure of a short, effectively, in one of the cables from the underground powerhouse to the substation on the surface. The powerhouse is about 500 feet underground.

Q Was this cable exposed or was it underground?

A It was an armoured cable, in the cable duct in a vertical cable tray, between the underground unit and the surface, adjacent to an elevator.

A MR. MORRISON: Ms. Marx, in a shaft.

A MR. CAMPBELL: Yes.

Q Okay. And what was the reason for the failure of this cable?

A We are not 100 percent sure. We assessed the failure as a premature failure of the cable, but it was evident -- the cable had some damage on the exterior, which eventually, because of the environment it was in, it is a very wet environment 200 feet underground, it is damp, would have caused

the failure to occur.

Q Was this something you discovered after the fact, or was there some indication, through inspections, prior to that?

A No. This was based on the investigation that took place after the failure.

Q Right, okay. Is this something that could have been detected through an inspection?

A MR. MORRISON: I am not sure that -- you know, I mean Hector can give you some additional -- it is in a cable bound in a shaft. We couldn't see it. It certainly wasn't anything that we detected prior to. Could you have detected it? I don't know that. But it certainly wasn't something you could visibly see and know that there was a cable in there shorting out.

Q So if it was a premature failure of this cable, then would it be fair to say that the chances of that happening again are pretty slim?

A Well, I am not sure, you know, in the sense ... yes, slim, but it hadn't happened before. The cable had been there for a number of years.

Q But, essentially, it sounds like it was a defective cable perhaps?

A It could well have been, yes.

A MR. CAMPBELL: I would say, for sure,

a contributing factor was the environment that the cable was in. It is a very wet environment. And the area of failure was wetter than other parts of the shaft, so that would certainly have contributed to it.

Q Have any steps been taken to address that situation?

A Yes. Well, we have replaced those cables. And as part of the Aishihik Third Turbine, we have -- we currently plan to have a completely redundant run of cables, so that a single cable fault would no longer have the ability to take out both units.

Q Okay. And I believe Mr. Bowman said before that the severity of that outage was exacerbated by the fact that backup generators were not able to start?

A MR. MORRISON: I am not going to put words in Mr. Bowman's mouth, but let me be clear about something. The severity of that outage caused other problems. There were some backup generators on the system, not ours, not ours, that did not start. And when you look at the list in the Plan, on page 18 on the summary, there are some YECL units which did not immediately start. They eventually got them all started.

But just in terms of describing, in simple terms, we had 30 megawatts of load on that system.

It went looking for a home. We did not have a spare 30 megawatts operating, and it knocked the entire system, the remainder of the system, out, and it took a little while, in terms of testing that system, before we were able to start turning things back on. And it did cause some difficulties, and some of the turn-on had to be done manually, but it got turned on.

As I said, there were some difficulties Yukon Electric had in getting some of their generators on, but they eventually did get them on.

Q And I am not trying to point fingers here.

A I appreciate that.

Q I am just trying to understand what caused the outage and what this means for your current planning criteria.

Do you know if steps have been taken to address that situation with these backup generators? Is there anything that was done, that

could be done?
A Yes. Subsequent to this, we have sat down on a number of occasions with Yukon Electric, and one of the exchanges of information that we now do is, prior to that -- just as an example, if they had taken one of those generators out of service for maintenance, we would not have known that. We now

know that. So we have agreed -- we have taken steps so that we can see their system, which means that we can shorten the turnaround time in terms of turning the system back on. We have been working very closely to make sure that we know where their capacity is on the system, when it is not available, who we can contact if we need to. And so we have worked, I think, very well together, to make sure that we can respond better the next time this happens.
Q So based on that, would it be fair to say, Mr. Morrison, that if another outage occurred, it would be less severe? Likely less severe?
A I am not the right person to ask that. If we lost the Aishihik line again, it would be as severe in

the sense of, it would still knock the system out. We don't have a system that can take that kind of a hit.

Would we get it back up a little quicker? Yes, we would get it back up a little quicker. But, you know, if we say -- and I don't have the exact time in my head, but we were out for 12 or 13 hours. Could we get the whole system back in one hour? No. Could we get it back in, say, 8 or 9 hours, versus 12 or 13? It's probably more like that, but it would be out for a long time.

Q Mr. Campbell, did you have anything to add to that in terms of the technical aspect of those questions?

A MR. CAMPBELL: No. No. I think it has been said.

Q With respect to the N-1 criteria, I would like to go back to that. So it is assumed to be a peak, at the annual peak, and the worst outage, which is the Aishihik line. In your assumptions, are you assuming a drought year or a non-drought year?

A MR. MORRISON: Drought year for what, Ms. Marx, if you could help me here?
Q I guess, in terms of the capacity --
A Of Aishihik?
Q No, not of Aishihik. Just generally. I am just asking, generally, for the assumptions that are within the N-1 criteria, and I guess as it would relate to the Whitehorse Hydro Plant for example?
A I mean if somebody can --
A MR. BOWMAN: The answer is that it is based on the firm capability of the system, which is the winter output of Whitehorse Hydro that you can rely upon, the firm winter capability during a drought, correct.
Q During a drought?
A Yes.

Q That is the 24 megawatts?
A That is the 24 megawatts, correct.
Q And in a non-drought year, what is the firm winter capacity of the Whitehorse Hydro plant?
A Well, we answered an IR to this effect, and it would probably be helpful --

Q Sorry, I just do not recall.
A That is fine. It is not an easy number to comment upon.
Q Perhaps you can just tell me, is it much more?
A It is not much more. On a non-drought year, you will see that plant putting out more like 26, instead of 24, on a consistent basis.
Q And under the N-1, you are also, of course, assuming that the wind generation is not operating?
A That is correct.
Q The other assumption I think that is being made is that, assuming you have the Carmacks-Stewart line in place, that the Mayo-Dawson grid is also at its annual peak. Is that correct?
A No, not necessarily. In the case where we are modeling the two systems being interconnected, the peak load for the combined systems is effectively modeled off of the peak load for WAF, by adding in simply the number of annual kilowatt hours for the Mayo-Dawson system. We have not done detailed work

on the peaks on each system and how coincident they

are, and the relative load factors. So, in general, it just assumes that Mayo-Dawson is like an additional load growth on WAF that would otherwise occur at the same load duration curve and the same load factor.

A Okay.

A MR. CAMPBELL: We did attempt to go back over a few years and see what was the peak factor, that they were the same at the same time, and it was relatively close. When we looked at the last couple of years of WAF peaks, the peak loads, at the same time on the Mayo-Dawson grid, were within a hundred kilowatts of their all-time peak. And that is not unusual. In the Yukon in the wintertime, if it is cold in Whitehorse, it is colder in Dawson.

Q So you are assuming that the Mayo-Dawson grid would be able to contribute 6 megawatts?

A The assumption was based on basically the back-up diesel, that is currently available in Dawson and Mayo, would be available again as back-up for the WAF grid, but that the hydro would not be, that it would be fairly close to being fully utilized at the time?

A MR. BOWMAN: And just to make sure

the record is clear, it could be as much as 6 megawatts at the time of interconnection, but the more the Mayo-Dawson grid grow, the less it has to contribute.

Q Yes.

A So by the time of 2012, when we tend to model the system, it is down to about 5.6.

Q Right.

A The other comment that might be helpful here, for those who follow the details, in terms of the peaks we are talking about in each case, we are talking about an hourly integrated peak, not an instantaneous peak for the system. All of the modeling works off an hourly integrated peak. Instantaneous peaks will be somewhat higher due to fluctuations during the hour, but we work off of that. So there are factors on the optimistic as well as the pessimistic side of the N-1, if you like.

Q I had asked you some questions earlier about -- I think I directed them to Dr. Billinton, but I want to confirm the way YEC did the calculations with respect to the assistance coming from the Mayo-Dawson grid under the LOLE criteria. And am I correct that it was done in the same way as that

table I had referred you to, with respect to the

Aishihik Third Turbine and the Aishihik transmission line, in that you started with the LOLE calculation, and then you just added in the 6 megawatts of capacity to determine what the surplus or shortfall is?

A I don't have the table in front of me anymore, but the table you were looking at was simply additive across the rows, that's correct. The Mayo-Dawson column, though, is a little different than the others in that it is not citing a value of capacity on that system. It is actually taking the WAF system and the Mayo-Dawson system, plus the incremental losses that were expected to occur on the interconnection, the Carmacks-Stewart system, and taking all of the loads and modeling them as one system, not in a detailed modeling way the way the computer model that is now being prepared could do, but considering them all as one system, looking at a total peak, using the LOLE approach, and coming up with the 5.6 number by that route. And I was trying look for the IR quickly, but I am not

going to find it, but to talk about how the losses on the Carmacks-Stewart were considered and how the two grids were integrated into one consistent load at the time of interconnection. It is answered in one place in the IRs, and I can look it up if you

like.

Q That is fine.

Has the probability of outage on the Carmacks-Stewart line been factored in to your calculations under the LOLE?

A No.

Q And is that something that you would look at doing?

A Based on the principles that Dr. Billinton was laying out earlier, it did not seem needed, to Yukon Energy, to try to model that into either of the criteria. Given that we are talking about a relatively small number of megawatts at the end of that line that are being contributed in the N-1 type criteria, that would drive you to thinking about N-2, the .66 percent Aishihik failure happening at the same time as the Carmacks-Stewart

failure, and we have not talked about trying to protect the system to that level. And even if someone were wanting to talk about that, the Carmacks-Stewart line would not be the next biggest unit you would want to think about. That is the same size as one of the big diesels at Whitehorse basically, and nowhere near the size of the hydro units in Whitehorse.

In terms of the LOLE criteria, YEC relied on the principles in Dr. Billinton's report, that it

really was the unique characteristics of Aishihik, where you have that much generation compared to the size of the system at the end of a line, that you would want to pay attention to that transmission line. As an example, today there is generation at Faro, but we don't model the Faro line as its own probability. That generation at Faro is assumed. That line is assumed to be up in any of the cases where the Aishihik line is going to cause you problems, or the other unit considerations that go into the LOLE formula.

Q Dr. Billinton, can I just ask you one other

question? As a follow-up to what we were discussing earlier about the use of the industry averages, are you confident that the industry average used, for the probability of failure of the transmission line, is a good proxy for what it actually is?

A DR. BILLINTON: When considering the data that is available, I think it is the best possible estimate that we could use at this point in time.

Q Okay, thank you.

Given what Dr. Billinton said earlier, when I was asking him about the fact that the worst-case scenario is a failure of the Aishihik transmission

line, and why not focus your efforts there ... so if I could pursue that a bit in terms of why YEC has decided not to pursue twinning of the Aishihik line.

A MR. OSLER: I will start, and we will see how much more detail you need.

In the opening comments, I summarized it, I

think, as follows: We did take it seriously, given the new criteria, as an obvious option to examine, and a fair amount of time and energy was, in fact, devoted to it. At one point I thought it was the horse with the best chance of coming out in a short list, given some of the comments.

Two things affected its ultimate ranking at this moment in time. One was the fact that it takes time to licence a plan and build it, and there is a fair amount of uncertainty at the moment with respect to the time periods required. We were going into the Carmacks-Stewart project. We want to learn, from that one, what the new Yukon process takes. But it wasn't something that we could reliably say we can get this outcome within a certain date, and the senior people of management and Board of YEC, given some of the information about the capacity shortfall, wanted some assurances as to when things could be done in the

near-term.

The second problem is that it is lumpy. You get it all, and it costs 16 to 19 million dollars,

according to the reports we filed, based on cost estimates that were back at the time we were estimating lower numbers, if you like, for Carmacks-Stewart. That means that, effectively, you were getting, at the moment, about 15 megawatts, in round numbers, extra capability, for about a million dollars a megawatt. And looking at the Mirrlees units, you had the advantage as follows: You had the incrementality, you could go at them one by one, and half the cost or better. You could also get a certainty, relatively speaking, as to their price range, whereas the advice we received is you are not going to know the price of a transmission line until you get to the tendering stage. The markets are potentially volatile, and we have discussed that separately.

Q But that same factor would play into the building of the Carmacks-Stewart line?

A No question, but we are not building the Carmacks-Stewart line as a dominant lead project to solve the capacity problem. It is one that is being looked at for a variety of reasons, and if it gets built all the way to Stewart, it will

contribute, potentially, a small part of the solution to the capacity issue. But it was viewed primarily as an opportunity project.

Whereas YEC, looking at Aishihik twinning, could only look at it as something to be done in response to the new capacity criteria, where the Aishihik line redundancy would remove the need to have protection for all of that capacity, and therefore it was being looked at very, very much as a trade-off between what are our other alternatives. Very low usage of Mirrlees units was viewed by YEC's management and Board as an obvious alternative, and what were its attributes. You could do them incrementally, you could get a better handle on prices that were not going to go way out of the picture, and it was ultimately cheaper.

Q If I look at the Carmacks-Stewart line and the Aishihik transmission line, and you take the time from when you first start the planning process, get things under way, to the in-service date, is there a difference, in that time period, for the two lines?

A I think the short answer is, I don't have a strong opinion that could be backed up by having looked at it in the same detail for both. We obviously have looked at Carmacks-Stewart in considerable detail.

The issues we would have to consider, to make a judgment whether they are basically the same or one is longer or shorter, would be, on the one hand which issues would surface in the YESAB process with the First Nations along that particular route; and, secondly, how much easier would it be, if at all, because we could perhaps look at the option of working within the existing right-of-way. And we would have to balance those two. We would have to make a decision as to exactly which option we are looking at. And we looked at a range of them at one time. We would have to make a quick decision on that, and make sure it was a sustainable decision.

And if, in certain moods, we thought the regulatory process could proceed at the same type of time period or less, there is no reason why the construction should take any longer. And so the issue would be whether the existing right-of-way gives you some inherent advantage in the Aishihik transmission line. We have to go through the same process, we concluded; 138 kV would require us to

go up to the Executive Committee level and the YESAB process. At the moment, there is a fair amount -- it looks as though we may be the first project, the Carmacks-Stewart, to go through that

process, which I am not sure is what we would ideally like. But if Yukon Energy is going to have to rely on getting things licensed in the future, we might as well get started and get some practical experience between the regulatory authorities and ourselves, as to how to do this, and we may take a bit longer the first time than, collectively, we will take the second time.

So when this was decided way back, we were well back in the thought process, the dollars were ultimately, I would say, the biggest single lump, plus trying to explain to people, who were just digesting all that you have been discussing with Dr. Billinton as a brand-new set of concepts, the idea of building another line side by side with existing line, and explaining that in Yukon as a cost-effective way to use $20 million. I think, nowadays, we would say, with the Aishihik Third

Turbine, if there is a big load growth in the system, and depending on how other things come, this is an option that YEC will continue to look at very seriously, and probably refine its estimates of cost and timing and how to do it most effectively, when it has a few minutes to think more about it.

Q So it is not something you have completely taken

off the books as a possibility?

A I would -- Mr. Morrison can speak for the Corporation, but, as an advisor, I would say not to my knowledge at all.

I would just add, I think we have said it in one of the documents, but if, for some reason, the Mirrlees units had been concluded, after all the investigations had been going on, to not be a go for technical reasons, that is when the considerations about whether to spend money on new diesels, or look at this, became a pretty much closer horse race in terms of straight dollars, million dollars per unit for a new diesel, versus

this line at about 16 or 17 million. And that is when the timing issue certainly was foremost in the minds of people looking at this.

So I do not want to confuse people about where one factor became more important than the other. When the Mirrlees were around, and they are now confirmed, they are just hands-down a more cost-effective way to get the capacity for that very small amount of time that you were talking about with Dr. Billinton, to make sure the system was secure and reliable.

Q So it is factors such as cost and timing that have played into that decision, rather than looking at

issues like the fact that, with the Mirrlees units, you have the diesel emissions, the use of that -- like, from an environmental perspective, versus twinning the Aishihik line where you are not necessarily having to use as much diesel. That wasn't really a primary factor in the decision?

A You went through, with Dr. Billinton, the table of summer and winter load duration curves, and you pointed out the top 10 percent was a very low

number of hours. That is another way of saying that these units are meant to be back-up, and they probably won't even be on that curve because they are there to cover contingency. So unit efficiency and emissions were not a factor in the assessment, for the reasons that have been discussed. But the desirability, if you can find the right circumstances, the right opportunity to do it, for twinning the Aishihik line, if you can find the right timing, the right costing is self-evident, because you bring on line at least 30 megawatts, and probably 37, and, with re-runnering of the Aishihik units, probably more. So if you can find the right timing and the right conditions to bring on that lump and do it, and you have not spent a lot of money on new diesels in the meantime, maybe in this planning period it will reemerge as a major

opportunity.

Q I just have a couple quick questions I think I can ask in the last few minutes of the day here.

In response to YUB-YEC-2-9, YEC indicated that

the AH1 generator was rewound in 2003, and the AH2 generator was being rewound in 2006, with an October scheduled completion date. Has that been completed?

A MR. MORRISON: Yes, it has.

Q And so the output from the two generators, is that now 30.8 megawatts from the two turbines?

A I just want to make sure we are using the right math here. I just want to look at this for a second if that is all right.

Q Sure.

A MR. CAMPBELL: With the completion of the second rewind, certainly the electrical capacity has been increased, but we have not yet recommissioned the units. We need to ascertain the mechanical capacity constraint, which is both two-fold; the ability of bearings and the mechanical parts of the system, or of the turbine, to handle increased output from a torque standpoint and so on, as well as the ability to put more water through the penstock and through the wicket gates of each unit. So we cannot say for sure -- we

know, electrically, the capacity has been increased, and we will be doing some testing next year, once we are past the winter season, to ascertain, overall, can we increase the capacity of both units.

A MR. MORRISON: Ms. Marx, I just want to ask Mr. Campbell a question.

A MR. CAMPBELL: I should be clear that the electrical capacity of AH2 is the one that has been increased. The second rewind, we were able to obtain some better class insulation, increase the rating, reduce the temperatures, that will allow us to increase the electrical rating of the unit. With the first unit, there was really no significant increase, electrically, in the output of the unit.

Q Would you not have known that ahead of time? I am wondering if you did the rewind of the first unit, and it did not really increase the rating of it, is that something you could have known ahead of time?

A MR. MORRISON: Ms. Marx, let me help Mr. Campbell out here because the short answer to your question is, yes, we could have. We did not. We did not address that when we looked at the project, and you cannot go back and do it now. So, yes, we should have looked at it. When we did the

first unit, we were not in a system planning mindset, if you will. And it was a maintenance type of approach to the unit. It had reached a certain point in its life. It needed to be rewound, from a maintenance upkeep technical point of view. We could have looked at it. We did not. We hadn't adopted the philosophy at that point in time, which I think we now have, which is that we need to -- in terms of trying to build the necessary capacity, that we have got to look at all of the efficiencies within the existing assets and see, can we wring another 500 kilowatts or a megawatt out of these units as best we can.

So when we looked at AH2 and did the past rewind, we were in the mindset of looking at additional capacity requirements on the system. We made sure that we contracted for and got additional capacity. It was a little bit more money than not doing it that way. And, yes, there is still some risk, because as Mr. Campbell said, we still have to confirm the mechanical capability to, in fact, drive that, and we still have to confirm some additional water information, to make sure that we can actually get that additional capacity from the

electrical side. But it was worth the investment at the time, to make sure that, if the other pieces

fell into place, that we could do it, because it was such a small amount of money in addition to the dollars being spent. But, yes, we should have, and, no, we didn't.

Q So if I can just summarize, with the first AH1, the rewind was done more for a maintenance perspective rather than additional capacity. When it came to AH2, I assume it was also done for maintenance reasons, but in addition you were looking at it for increased capacity, and therefore, you had it done differently, spent a little more money?

A I think that is fair. We also had -- in the schedule, we were going to do AH2 as -- you and I can talk about it as maintenance, the engineers might call it some other technical term, but it needed to be done. It was in the schedule. When it came up in the schedule, we were in this Resource Plan process, we said, you know, in addition to just doing the maintenance work, we

need to see if we can successfully rewind it at a higher level, which we were able to do. So you are correct.

MS. MARX: Thank you.

Madam Chair, I think now is a good time to break.

THE CHAIR: Thank you, Ms. Marx.

I note that the Board will have a public input session tonight at 6 p.m., and we will adjourn until tomorrow morning at 9:00 a.m.

I do not know if I made that clear; the public input session is tonight at 6:00, and tomorrow morning we will meet again at 9:00 a.m.

(Proceedings adjourned at 4:00 p.m.)

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