YUKON UTILITIES BOARD

YUKON ENERGY CORPORATION

2025-2027 GENERAL RATE APPLICATION

P R O C E E D I N G S

Volume 3

October 23, 2025

Whitehorse, Yukon

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October 23, 2025

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(PROCEEDINGS COMMENCED AT 9:31 A.M.)

THE CLERK: Order. The hearing is reconvened. Please be seated.

THE CHAIR: Good morning, everyone. Welcome to the third and final day of this three-day application, oral hearing into the application, which will go the full three days.

Just before resume questioning, I'll ask are there any housekeeping matters to take care of?

MR. HERBERT: Yes, Madam Chair. Is my microphone on. Okay.

First of all, we filed written undertaking responses yesterday, which have been provided to the staff.

May I ask that they be given an exhibit number, I think we're up to number 20.

THE CHAIR: Sorry, that's Exhibit 20, did you say?

MR. HERBERT: Yes.

THE CHAIR: Thank you.

EXHIBIT 20 - WRITTEN UNDERTAKING RESPONSES

MR. HERBERT: And Mr. Murchison also would like to provide a brief verbal response to one of the other

undertakings.

C. MILNER, J. EPP, S. CUNHA, P. MURCHISON (For Yukon Energy Corporation), previously affirmed

A. MR. MURCHISON: Thank you, Paul Murchison, Madam Chair. The question was asked about the cost estimate for the Lewes Boat lock replacement and the cost estimate including the road and if it includes a road construction or not.

Our current estimate for the boat lock construction and the road all inclusive is $41.7 million.

THE CHAIR: Thank you. So if there's more procedural housekeeping matters, Ms. Bentivegna, are you ready to proceed.

MS. BENTIVEGNA: Yes, Madam Chair. Thank you.

MS. BENTIVEGNA QUESTIONS THE PANEL:

Q. MS. BENTIVEGNA: Now these following questions relate to the Atlin Hydro energy purchase agreement. And if we can distribute Aid to Questioning Number 12, which relates to Board Order 2024-05, Appendix A, paragraph 326, Directive 20.

Now, panel, if you could go to Appendix 5.4-1 -- sorry, 5.4B-1 in the application, Exhibit 1-A at PDF pages 466 to 468. And I'll start with my questions on

the section that talks about the '23/'24 GRA heading. So if you see that, it says: (as read)

> "As stated in Yukon Energy's 2023/24 GRA compliance filing, the central issue raised by the Board in the 2023/24 GRA was the current viability of the project."

And talks about Directive 20. And that quote or that passage ends with: (as read)

> "The Board, in its response to the compliance filing, did not provide specific comment on the Atlin Hydro EPA costs, as such Yukon Energy did not cancel the project and under its then current practices maintained the project cost in construction work-in-progress."

Now, in this section that we're -- that I've just referred you to, it's an overview of what happened after the Board ruled in paragraph 326 of the Board Order 2024-05, Directive 20.

That YEC should address in it's compliance filing application to that decision whether the project still had a reasonable likelihood of proceeding, if not the, the Board indicated that expensing of the project should

be considered.

Now, as I've just read, YEC noted that because the Board did not make a specific ruling in the compliance filing decision about what to do about the Atlin Hydro EPA costs, YEC determined that it should continue to maintain the project costs in its construction work-in-progress accounts.

Now, that is my focus, but I hope I have not -- it's a high level, but I have not missed anything that you'd like to point out from that excerpt. Now so seeing there's nothing I've missed, I'll go on.

So to go back to the top, the very top of Appendix 5.4B-1 on PDF page 466, where do you have in CWIP or work-in-progress continuity extract for showing of the 2025 opening balance expenditures of the next three years and the forecast 2027 yearend closing balance, which shows $1,782,100?

Now, I'd like to focus on the $100,000 forecast expenditure for 2025 for a moment and discuss it in the context of the paragraphs immediately under "Project Update" heading on PDF page 467.

Now, my first question is in regard to that first paragraph under the heading -- under the heading "Project Update", which I take to indicate that although there has not been significant work on the project after the

'23/'24 GRA at the time of this application filing in May of this year, the EPA's conditions precedent had been extended to June 30th.

Now, looking at your response to YUB 69A and B, part 4, iiii, which is found on PDF page 454 and 455 of Exhibit 4. I'd like to go to page 455 of that PDF response, so where you say: (as read)

"Yukon Energy has not performed significant work on this project since 2024."

And it goes on.

So that appears to say that you were able to achieve an extension of the EPA condition precedent between YEC and the Tlingit Homeland Energy Limited partnership to January 1st, 2026. Is that correct?

A. MS. CUNHA: Madam Chair, that is correct.

Q. Thank you. Now, the statement in 69, YUB 69A and B, that part 4 response also includes the statement: (as read)

"The 2025 forecast costs are dependent on finalization or extension of the conditions precedent."

I note that this is similar language to what YEC used in its discretion of the Atlin Hydro project in Appendix 5.4B-1 business case, which also includes a statement to

that effect, that: (as read)

"The 2025 forecast costs are dependent on finalization or extension of the conditions precedent."

So where are we currently at with respect to the forecast costs for 2025 that were forecast at 100,000 at the time that the application was prepared?

What I'm interested is right now, what if any costs have been incurred or if you still foresee that you'll be spending a forecast of 100,000 in 2025?

A. MR. EPP: Madam Chair, we can take that away to find out the spending in this project to September 30th, 2025.

Q. All right. So we'll take that as an undertaking then, Mr. Epp.

A. MS. CUNHA: Madam Chair, I can also answer the second part of that question which was potential anticipated costs.

As the Tlingit Homeland Energy Development Corporation seeks funding from the federal government, one of the options that they are assessing for additional funding is perhaps adjustment of the electricity purchase agreement in the terms there, so this money was originally forecast, should Yukon Energy have to re-enter discussions with the development

corporation about terms of the electricity purchase agreement to close the funding gap. So that was the purpose of the '25 costs.

Q. But to date there haven't been any such discussions, have there?

A. MS. CUNHA: As Mr. Epp said, we can go back and look at the actual costs to date to September 30th.

Q. Great. And if in that undertaking you can explain what the costs were for, if any costs?

A. MR. EPP: Yes, we can.

Q. And whether you continue to maintain that forecast of 100,000.

UNDERTAKING - TO EXPLAIN WHAT THE COSTS ARE FOR RE THE ATLIN HYDRO PROJECT AND WHETHER YEC CONTINUES TO MAINTAIN THE FORECAST OF $100,000

Q. MS. BENTIVEGNA: And to build on that, if there were -- are there any forecasts for spending in '26 and '27? We don't see any forecasting on expenditures for those two years, but I want to determine whether you foresee any additional forecasts costs for those two years.

A. MS. CUNHA: Madam Chair, an important note here is that this project is a project that is owned by the Taku River Tlingit Development Corporation, so it

is an independently owned project.

I say that because our participation and forecasted costs will be contingent on the proponent's ability to find additional funding from the federal government to advance the project. Should that happen then certainly there could be and I anticipate there would be additional costs for Yukon Energy in '26 and '27 to finalize agreements that, at this current state, have not yet been finalized.

Q. But at this stage, you don't foresee that happening since you haven't forecast any expenditures?

A. MS. CUNHA: Madam Chair, the forecasts at the time of the application was back in May. As mentioned it really would be contingent on the progress made by the proponent.

Q. And seeing that there have been a number of extensions for meeting or complying with the conditions precedent, does YEC believe that there will be further extensions after that January 31st, 2026, deadline, if the conditions haven't been met by then?

A. MS. CUNHA: Madam Chair, extending the conditions precedent would be conditioned on whether or not the proponent was seeking -- was achieving advancement on getting the funding support or the permitting that is required for the project. So it

would really be dependent on the progress made by the proponent.

Q. And to date, as far as YEC knows or is concerned, have there been advancements towards funding or project permits, any advances in those areas?

A. MS. CUNHA: Madam Chair, in preparation for this hearing, we did receive an update from the proponent as of September 30th of this year. They have mentioned that they have received construction permits for the project.

They do continue to seek funding from the federal government to close the funding gap, and that they have active applications into the critical minerals funding application. They have mentioned that detailed design is complete on their transmission line. That -- 90 percent detail design is complete in their civil and structural design, and that they have advanced detail design of their turbine and generator as well.

So at that high level, as being is reported by the proponent, they are seeing progress in achieving permits and obtaining funding to this point.

Q. Thank you. Would you be able to provide a copy of that update to the Board?

A. MS. CUNHA: Yes, Madam Chair. We can take that as an undertaking.

UNDERTAKING - TO PROVIDE THE UPDATE THE YEC RECEIVED FROM THE PROPONENT OF THE PROJECT OWNED BY THE TAKU RIVER TLINGIT DEVELOPMENT CORPORATION AS OF SEPTEMBER 30TH OF THIS YEAR

Q. MS. BENTIVEGNA: Thank you. Now, going to Table 5.8 from the June 30th supplementary information submission at PDF page 31 and 42, and that's Exhibit 2-A. I'd like to explore how YEC got to the current 2025 opening work-in-progress balance of $1,682,100 at PDF page 39, so if you look at that Table 5.8.

Now, if you can explain -- pardon. I believe that's page 36, and I misspoke. That's Table 5.8 at PDF page 36 that shows the '23 and '24 actuals.

Now, can you tell us, not necessarily for every expenditure, but at a higher level, what YEC has spent the money on this project to get the opening balance, the 2023 opening balance, of $1,474,200?

A. MS. CUNHA: Madam Chair, at a high level, those costs were incurred to negotiate and draft electricity purchase agreement with the proponent, as well as to draft the interconnection and implementation agreements that are necessary in order to safely operate the system, and one of those agreements is an agreement between Yukon Energy and the proponent and

the other is an agreement between Yukon Energy ATCO Electric Yukon and the proponent recognizing that the project would also interconnect with ATCO Electric Yukon's transmission system.

Q. So basically it was negotiating the EPA agreement, and you just mentioned the interconnection agreements as well that would be needed to tie the project into the Yukon integrated system; is that correct?

A. MS. CUNHA: That's correct.

Q. Now, can you explain what the '23 and '24 spending of 134,500 and 73,400 respectively relate to. So the '23, the 134,500 and the '24 is 73,400, so if you can tell me what those costs relate to?

A. MS. CUNHA: Madam Chair, I can take an undertaking to get the specific line items and details of those two items.

UNDERTAKING - TO EXPLAIN WHAT THE '23 AND '24 SPENDING OF 134,500 AND '24 SPENDING OF 73,400 RESPECTIVELY RELATE TO IN TABLE 5.8

Q. MS. BENTIVEGNA: Thank you. Now, still in that updated Table 5.8, can you explain how you've gotten to the current 2025 opening balance of $355,800 for contributions toward the Atlin EPA, and that is PDF page 36 again -- 39 of the updated table.

A. MS. CUNHA: Madam Chair, as part of this there would have been some costs that Yukon Energy would have incurred related to perhaps a system impact study that the proponent would have reimbursed Yukon Energy for.

Q. Can you confirm that?

A. MS. CUNHA: I can take that back and get the details of it.

Q. Thank you. So that is an undertaking?

A. MS. CUNHA: Yes, it is.

UNDERTAKING - TO CONFIRM WHAT THE COSTS ARE RELATED TO RE THE CURRENT 2025 OPENING BALANCE OF $355,800 FOR CONTRIBUTIONS TOWARD THE ATLIN EPA, PAGE 39 OF THE UPDATED TABLE

Q. MS. BENTIVEGNA: Thank you. Now, also there's a $288,500 2023 opening balance and the further expenditures of 66,223; is that correct?

A. MS. CUNHA: Madam Chair, that is what's noted on the table.

Q. Thank you. And can you explain why the contribution wasn't paid all at once and whether the contribution stopped increasing -- or the reason why it stopped increasing after 2023?

A. MS. CUNHA: Madam Chair, if I may, as part of the previous undertaking that we would take for the

355.8, I'd be happy to look into those details, but it would be premature for me to speak to that at this time.

Q. Thank you. Now, if there were -- if the conditions precedent were not met and there's an extension after January 31st, 2026, is there any potential for YEC to receive additional contributions?

A. MS. CUNHA: Madam Chair, at this point, no.

Q. Now, going back to Appendix 5.4B-1 write-up, now, there's some sections under the heading "Conclusion" that starts at the bottom of PDF page 467 of the application and continues to the next page, so that's Exhibit 1-A.

So you'll see it starts, the first paragraph starts with: (as read)

> "Based on current performance and guidance from the prior GRA, it is Yukon Energy's position that at the time of filing of the 2025-27 GRA, there is still uncertainty about the project's ultimate viability; the project is still being pursued; and Yukon Energy cannot confirm, with certainty, that the project will not proceed."

Now, that -- if you go to the statement at the bottom of page 467 that says -- that I've just read that says: (as read)

> "Yukon Energy cannot confirm, with certainty, that the project will not proceed."

It's a phrase that's very ambiguous or difficult to understand because of the phrasing.

So does YEC believe that the project will proceed?

A. MR. MILNER: Madam Chair, Chris Milner. I'll lift this up a little bit just because of the general nature of the question. We can't confirm that it will proceed or not proceed because it's entirely outside of our control.

What we can do is stay in touch with the proponent, watch the project, watch for indicators, they are making significant investments in this project, like in the millions of dollars.

There have been a number of government commitments over the years, commitments and then projection of those commitments and then other agreements outside of our control again between nations.

But this is the kind of project that we want to see on the system. It's winter capacity and winter energy at the same time, and we're doing our part

within reason to sort of keep the EPA alive.

Now, that said, all we can do is really watch for indicators of success. The most recent indicator is that they have made some progress with the BC government through permits and as well as the ongoing financial support through the BC government.

So there's reason to believe they're advancing it on their side, and we have to do a cost benefit analysis on whether or not to keep the EPA alive in its current form, through conditions precedent, which is largely administrative legal process for us or to close it and then open it up again, once there's more certainty on the project.

I think it's fair to say that in the next budget cycle for whether it be the territorial government or the federal government, as it will involve both, we see indications that it's nowhere on the radar, then we'll have this conversation again and it would be well within our -- well within reasonable to -- what's reasonable to close the project out and attempt to recover costs at that time.

Q. So, Mr. Milner, just to followup, I just wasn't clear what you meant by closing it and then maybe reopening it or -- if you can just elaborate on what you meant.

A. MR. MILNER: Well, I think if the -- if we

were -- now we're getting into regulatory language, so I might actually pass this over to Jason.

A. MR. EPP: So if -- I believe Mr. Milner was saying that if the federal and territorial governments came out with budgets in the next year and that there was nothing in it, it would be reason for us probably to conclude that there's -- it would likely not proceed and then we would close the -- this project as it exists and ask for it to be recovering rates after that.

If, however, it was subsequently was reopened or there was progress by Atlin, then we would have to reopen it after that time. Basically start over from zero with a new project.

Q. All right. Thank you.

A. MR. MILNER: I guess I just emphasize that it's not actually our project. Right? Our project is the EPA portion of the project. Their project is the actual project, the capital project.

Q. Now, again, just to clarify that last paragraph under "Conclusions", is it that if YEC gets a clear direction from this Board, not your board of directors, that there should not be further expenditures on the project, would then YEC propose to expense -- I understand your explanation about closing it, but based

on no further progress, but would the YEC propose if the Board were to direct that it basically, you know, that further expenditures are not reasonable in this context, would then YEC propose to expense a net amount of $1,326,300 for operating expenses in 2025 reflecting the gross expenditures to the end of 2024 of $1,682,100, less the contributions of $355,800?

A. MR. EPP: So, Madam Chair, Yukon Energy would recommend that the net amount be included either as an expense in 2025 or alternatively since it was over a million dollars, typically what the Board has done in the past and what Yukon Energy has done in the past is propose amortization of that over a 10-year period.

Q. And if you can give me your views on how YEC would view such a direction from the Board on this particular project. I understand you saying you want to -- that it's still viable and you want to continue with it until it's determined that it may not be viable as determined by YEC.

So I'm just wondering if you believe that such a direction is necessary from the Board or you would rather continue with that until such time that YEC determines that it's no longer viable?

A. MR. EPP: Madam Chair, first of all, we --

whatever -- if the Board makes a ruling, we will comply with that for regulatory purposes, and if that means expensing it at a certain time or amortizing it, that's what we will do for the rate making purposes.

As a business, if we still feel like we need to spend some money on the project for whatever reason, that's a separate business decision outside of the rate making process.

Just as an -- sort of a correction, maybe an update to our prior comment regarding the closing of this in 2025, yes, that is possible. The other option is not closing it until 2026 because the conditions precedent agreement has been extended until then, but just a comment I guess.

Q. Sorry, what was that, not 2026?

A. MR. EPP: The condition --

Q. Not until 2026?

A. MR. EPP: The conditions precedent has been extended to 2026, therefore that may be a more appropriate closing date for the project.

Q. Thank you.

A. MR. EPP: Of course, subject to the Board's decision.

Q. And if the amount of the expenditures to date, the 1,682,000 and change, if that were to be expensed,

would you be considering that if the Board were to give you that type of direction that those costs should be considered prudent?

So basically, if you would rather -- and basically the reasons why those expenses would be or should be considered prudent by the Board, and I'd be happy if you want to think about that and as an undertaking rather than having to answer off the cuff.

A. **MS. CUNHA: Madam Chair, I would say that we believe that, yes, indeed those costs of 1.6 and change incurred to date are prudent. They are an agreement for Yukon Energy to secure power, if the project is received, the exact kind of power that we need, winter dependable capacity and winter dependable energy that is renewable.**

So given that the needs, the specific needs of the Yukon electricity system, winter energy, winter capacity, these costs and this project are a direct correlation to that as well.

Q. Thank you.

MS. BENTIVEGNA: Madam Chair, on those questions I know we distributed the aid to cross, but we don't need it to be entered as an exhibit.

THE CHAIR: Very well. Thank you.

Q. MS. BENTIVEGNA: Now, moving on to the BESS

projects and the business cases for the BESS project and the thermal replacement, the 16.5-megawatt project. And what I'm focusing on is YEC's capital expenditures and addition forecasts for those two projects.

Now, would you agree that the need for both of these projects was already approved in prior YEC filings prior to the 2025/'27 GRA in May of this year?

A. **MR. MURCHISON: Madam Chair, Paul Murchison. Yes.**

Q. Thank you. Now, would you agree that because we don't have final costs for either the thermal replacement 16.5-megawatt project or the BESS project because the former is being finalized in 2025 and the latter is coming into service in 2026 or is planned to come into service in 2026, the Board is not testing prudence of YEC's final costs on these projects in the current -- in this current proceeding and is only required to approve YEC's updated capital projects forecast -- excuse me -- and not final costs?

A. **MR. EPP: Confirmed.**

Q. Now, going on to the Whitehorse Power Expansion project, the Whitehorse Power Centre's project.

Now, I have a few questions on the project that was called the Whitehorse Power Expansion project in the original application, for which now I understand based on the report provided as part of YEC's response

to YUB-8 that YEC now calls the Whitehorse Power Centre project what was formerly the Whitehorse Power Expansion project; is that correct?

A. **MS. CUNHA: Madam Chair, that is correct.**

Q. Thank you. Now, to start with, I'd like you to go to the updated Table 5.8 from the June 30th supplementary information filing and that's PDF pages 31 to 42 in Exhibit 2-A, that table, but within that updated table, if you could go to PDF page 40 where you see the 2027 closing work-in-progress balance for the Whitehorse Power Expansion project which seems to be in the amount of $54,200,200.

Now, from the documents filed in the June 30th submission, there seems to have been a change. The fact that there is a $54,200,200, 2027 yearend work-in-progress balance indicates, based on Table 5.8 information, that YEC believed at the time it prepared the application that the Whitehorse Power Expansion project would not have had any facilities in service by the end of 2027 but that YEC has now determined that having some facilities in service by the end of 2027 is now possible.

In fact, in the YEC's opening statement to this GRA, I believe that YEC now takes the position that completion of the south power centre and into service

by December 2027 must be done.

Do I understand that correctly?

A. MS. CUNHA: Madam Chair, that's confirmed.

Q. Thank you. Now, in addition to this supplementary information of June 30th, YEC provided a table on PDF page 7 at that same document that provided total forecasts for the projects, including the Whitehorse Power Expansion project, that did not at least at that time, have forecasts for any capital additions during the '25 -- 2025/'27 test period.

In fact, the information about the Whitehorse Power Expansion project appears to forecast a total cost, subject to an asterisk, of 114,200,000 which the schedule on PDF 7 of that same supplementary information indicates will occur either in '28 or '29.

Is that -- do you see where I'm referring to?

A. MR. EPP: Confirmed, yes.

Q. Thank you. Now, the single asterisk besides the '29/'30 on the Whitehorse Power Expansion line is associated with the following text: (as read)

"Reflects Phase I of the project."

Now, based on the information available to the Board in the June 30th supplementary information, the way that the Board interpreted this information was that the Whitehorse Power Expansion project would cost 114.2

million to the end of the first phase of the project, thus leaving us with the impression that the ultimate costs of the project reflecting the costs of any post-Phase I expenditures would be even higher than that.

Is our understanding correct or is the costs of both phases that 112 -- 114.2 million.

A. **MS. CUNHA: Madam Chair, that would have been both phases, would have been the 114,200.2 at the time.**

Q. So just to confirm, that would have been both phases?

A. **MS. CUNHA: That is correct.**

Q. Thank you. Now, looking at YUB-8A and B, Attachment 1, from the Exhibit 4 starting at PDF page 131, if you look at the table in that document found at PDF page 134, regarding the table Whitehorse Power Centres project proposed completion phases.

And now if we go to the bottom of PDF page 135 of that same exhibit under the heading "Costing of South Whitehorse Power Centre," this continues on the next page, "Costing of South Whitehorse Power Centre," and there, there's an explanation.

Now, the statement that the cost of construction and commissioning of the South Whitehorse Power Centre's initial 15 megawatt was not included in the 2027 GRA revenue requirement due to uncertainty of costs and timing of completion.

And can you provide clarification, because on the one hand the statement could be suggesting that the 56.9 million expenditure, is a new expenditure or on the other hand since the work-in-progress balance in the updated Table 5.8 2027 closing balance for the Whitehorse Power Expansion project was about 54.2 million, which is pretty close to the 56.9 million.

So could this just be a change in YEC's confidence that the 15-megawatt south power centre build could be completed by the end of 2027 rather than it being in addition to work-in-progress?

A. **MS. CUNHA: Madam Chair, it reflects that the project now must be done by December of 2027.**

Q. Now, could you undertake to provide an updated work-in-progress continuity schedule entry for the Whitehorse power centres showing any actual expenditures, additions and opening and closing balances for the years '23 and '24, as well as forecasts of opening and closing balances, capital expenditures and capital additions for the years '25, '26 and '27 that incorporates this -- the goal to complete the 15-megawatt south centre portion of the project at a cost of 56.9 million?

A. **MS. CUNHA: Yes, absolutely. We'll take that as an undertaking.**

UNDERTAKING - TO PROVIDE AN UPDATED WORK-IN-PROGRESS CONTINUITY SCHEDULE ENTRY FOR THE WHITEHORSE POWER CENTRES SHOWING ANY ACTUAL EXPENDITURES, ADDITIONS AND OPENING AND CLOSING BALANCES FOR THE YEARS '23 AND '24, AS WELL AS FORECASTS OF OPENING AND CLOSING BALANCES, CAPITAL EXPENDITURES AND CAPITAL ADDITIONS FOR THE YEARS '25, '26 AND '27 THAT INCORPORATES THE GOAL TO COMPLETE THE 15-MEGAWATT SOUTH CENTRE PORTION OF THE PROJECT AT A COST OF 56.9 MILLION

Q. MS. BENTIVEGNA: Thank you. Now, if we go to your response to YUB-69 in Exhibit 4, if we look at the budget, project budget, at page 453 showing a project budget breakdown by year from '25 to '29 and in total, so if you see that table. This table identified an initial project budget.

Was this budget shown on PDF page 453 prepared earlier than the budget that reflects the projected expenditures totalling 56.9 million on the 15-megawatt south power centre portion of the project?

A. MS. CUNHA: Madam Chair, the budget table that is shown on page 459 of Exhibit 4 was done before the

updated estimate of 56.9 completed by 2027.

Q. Thank you. Now, do you see the statement: (as read)

"The initial project budget did not separately disclose AFUDC."

On line 24 of PDF page 453 of that IR package?

So since there's no AFUDC line item in the budget on PDF page 453, can you clarify whether the budget with an apparent total cost of 124 million includes an estimate of AFUDC, but which is not broken out from the forecast or whether AFUDC is excluded from the $124 million project cost estimate shown?

A. MR. MURCHISON: Madam Chair, AFUDC is not included in this estimate that is shown here, the forecasted expenditures at this time. And I'd say it's as we advance this budget, we will including AFUDC.

The budget that we have right now is a Class 4 budget, so there is some variability, so as we refine that, we will be including AFUDC as we move forward.

Q. And so followup on that, would it -- could you undertake to provide an updated budget for the entire Whitehorse Power Centre's project showing the current forecast to 2035 that includes all expenditures anticipated to the Phase 3 expand power centre's part of the project noted in Table 1 at PDF page 134 of the IR responses?

A. MS. CUNHA: So, Madam Chair, just for perhaps clarity and consistency, as the table on page 453 is the original budget for Phase I and Phase 2, is the undertaking to expand the scope of it to include Phase 3 and include AFUDC and include updated costs?

Q. To include that information but taking it to the end of what's described as the power centre -- the Whitehorse Power Centre's project, so not just Phase I and 2 but what's described in total?

A. MS. CUNHA: Thank you for that clarification. Noted.

UNDERTAKING - TO PROVIDE AN UPDATE TO THE TABLE ON PAGE 453 TO EXPAND THE SCOPE OF IT TO INCLUDE PHASE 3 AND INCLUDE AFUDC AND INCLUDE UPDATED COSTS, ESSENTIALLY TAKING IT TO THE END OF THE PROJECT

Q. MS. BENTIVEGNA: Now, in relation to the completion of the Whitehorse Power Centre project, Phase I by the end of 2027, yesterday Mr. Milner indicated that staff -- this is from the transcript, was: (as read)

"Scrambling to keep up with workload requirements."

And if you like, I mean, I can read the whole extract on that.

I'll start with the second: (as read)
"But I think the line of questioning makes a very strong assumption that workload stays flat. I think we've been crystal clear throughout this hearing and throughout our application that workload is not staying flat and in fact we're scrambling to keep up with that."

Now, in the context of those remarks and the growing workload of YEC, can you provide any comments on or how YEC plans to have, since it has a heavy workload, have this project, the first phase, completed by the end of 2027?

What assurances can YEC give the Board that this will happen. I know you've said it must, but how will YEC be able to do it, is the question?

A. **MR. MILNER: Madam Chair, Chris Milner with a high level context because it started with my comments yesterday and I will hand it over to Stephanie to give the breakdown of the succession of activities and how we plan to advance that project, as it must happen to meet winter demands.**

Certainly I think what you're seeing is the key drives behind the positions that are in the current

application support projects of this nature and are planning going forward. We're very aware of the challenges facing the company now in terms of meeting winter peaks.

That's why we prioritize within our strategic plan for the next five years winter firm capacity projects and deprioritize other projects that don't provide that assurance that winter peaks will be met. So we're having to do both prioritization, adding staff in particular in key departments, whether it be planning, because there's a huge regulatory aspect of this project, engineering because there's a huge project management and design component to this project, and others that we're dealing with, as well as really the engagement side of things and communication side of things because there's a huge communication engagement in partnership aspect of this project as well.

So at the highest level, those are the investments you're seeing in the FTEs that have been presented through the application, and we're having to prioritize our work right from the strategic plan implementation in Chapter 1 that I referenced in the opening remarks in order to deliver key projects like this. So that's the high level answer.

Now, we're going to have to have options as we

move forward in terms of delivering this particular project, and Stephanie can speak in more details around as to what gives us confidence in 2027.

A. MS. CUNHA: I'll start and then I'll ask Mr. Murchison to jump in, as this has been an all-hands-on-deck project.

The high level items that I can say is that, you know, with it being such a high priority critical project there are a number of streams that are happening in parallel.

So for example, you know, the first thing is we have selected that the fuel source for Whitehorse Power Centre South will be diesel. So we have made that fuel decision and can advance with that.

Mr. Murchison will speak to, you know -- we are advancing securing long lead items and I'll him to speak about the work that he and his team are doing there.

We are also advancing all assessment and permitting processes. We have established a senior officials group with the City of Whitehorse, Yukon government and other assessors and regulators to identify areas where not only can we find efficiencies in the process, but also where can we advance processes in parallel.

We also have ongoing engagement with Kwanlin Dün First Nation and Ta'an Kwach'an Council in regards to relationship, in regards to partnership opportunities as well as site selection.

As noted in this project we have sites and back-up sites to the back-up sites. You know, we are looking at every single possible location and we will be advancing those sites that, you know, have -- where possible zoning and other options that are already in place.

For those reasons, I would say that we are looking to -- we are moving forward to have this project done. We are moving forward with the fuel source, long lead items, moving forward with the assessment and all the partnerships that are needed to make this project happen.

I'll pass it on to Mr. Murchison to speak of the details.

A. MR. MURCHISON: Yeah, thank you. And I would say in my world, the concern or I'd say the timelines that we're dealing with are the timelines to be able to engineer, procure materials and equipment and then construct the site.

So I think I just would address -- I'll address sort of some of the long lead items because they're the

drivers sort of from a critical path perspective, and so for example transformers. We have been able to collaborate with ATCO on an -- and have been included in a larger ATCO procurement for transformers, so there's a larger transformer needed for this site and we'll be able to order that transformer within a month or so and that's what our expectation is because we were able to collaborate with ATCO on that procurement.

We also know that engines, you know, we believe we can get engines in about 18 months. We currently have a team in Vancouver looking at units at BC Hydro is currently constructing, and certainly -- and so looking at quickly making decisions on the appropriate diesel units for this site, so we could be procuring those early in the season next -- early in the year next year.

So that's -- so from -- so looking at critical path and those timelines, that's how we're looking at those items.

The engineering side of things, we have engineered these types of sites before, and when you look at the type of units that we're planning to put here, modular or say mobile units, we were able to build a site in Mayo in 2023 in a matter of one season, so we know we have the ability to design and construct a site like

we're planning to build here.

And then finally, I guess I'm just -- make sure -- I want to make sure I don't miss any notes on this.

Yeah, that's correct. So when I talk about the ability to build -- or install modular units on this site, we do have a back up, right, in getting this into service. We don't want to go there, but we can -- we would be able to install rentals if, for example, there is issues with procurement timelines as it relates to the diesel units that we put on the site.

So I think if you look at our ability to sort of design, construct -- design and construct this site and get the materials and equipment needed, we are getting ourselves well set up with confidence to be able to deliver this project.

Q. Thank you. Thank you. Now, moving on to YUB-8A and B, Attachment 1, now I'm interested in the paragraph that begins with: (as read)

"The capacity of each proposed generating station on PDF page 135."

And that's of the IR, consolidated IR responses, Exhibit 4. So what I'm referring to is: (as read)

"The capacity of each proposed generating station is greater than 5 megawatts and will trigger YESAB

executive committee screening. Yukon Energy assumes that a part 3 Utilities Act energy project and operations certificate will also be required prior to the start of construction of the new permanent thermal generation facilities."

And the last sentence there states: (as read)

"Yukon Energy will seek an energy certificate prior to commencing construction."

Now, the paragraph that discusses both the YESAB executive committee screening process and a YUB or Board proceeding for part 3 or under part 3 of the Utilities Act for this certificate.

Now, given that YEC has explained that these processes must be concluded before it will commence construction, what's the last state that both of these processes need to be fully completed in order to meet -- in order to allow YEC to have the 15-megawatt south Whitehorse portion of the project concluded in time to be fully operational before the end of 2027.

A. MR. EPP: Madam Chair, I will start with the part 3 part of this process, and Yukon Energy, a couple months ago, did submit an application to the minister.

Yukon government has been working on what it needs to do to issue the next steps, and we expect to be in a position to be before the Board very soon again with a part 3 hearing that would be completed hopefully by next summer.

Q. And with regards to YESAB approvals, what has been done to date, if anything, or if you need approvals. I believe you do, but I'm just wondering. Go ahead.

A. MS. CUNHA: Madam Chair, we have already submitted our prescreening and application for YESAA's executive screening process.

At this time we are just awaiting the committee's feedback on kind of what the project proposal guidelines will be. We anticipate submitting our project proposal in Q1 of next year.

From the Callison experience, we know that that -- we went through a pre -- we went through an executive screening process with our Callison site that we just completed last year or the year before, and we know that that process can take about 12 months, so -- 12 to 18 months.

So we're confident now that with the senior officials group that we've established, that we've brought the regulators, the First Nation governments and the key stakeholders together that we can find the

efficiencies and execute those processes in time for delivery of 2027 -- or end of 2027 I should say.

Q. And sorry, did I understand you correctly, that normally even going through the executive screening process is 12 months?

A. MS. CUNHA: Yep, exactly. So we anticipate that we would be in that process throughout 2026.

Q. And do you have any indication on having -- by having this senior officials group, if that may -- how that may shorten that 12-month period, not how, but an indication of how long it would take with the senior official committee, having that in place?

A. MS. CUNHA: Yeah, I -- with that senior officials group, I'm believe that, you know, I'm confident that we would have those, the decision document and the evaluation completed in that 12 -- 12-month period.

The reason for that is we've brought together the Yukon government, which is the body which will need to issue the decision document after the YESAA recommendation and we have brought YESAA, and we have brought the City of Whitehorse as well as Kwanlin Dün and TKC together.

Most recently just a number of weeks ago where the parties have identified where processes can happen in

parallel, rather than sequentially, so I would say that the effectiveness of the senior officials group is already finding efficiencies and ways to bring down any sort of timelines that are required.

Q. Thank you. So we've just talked about the processes that you need and certificates that you need before you can start construction, so currently do you have any idea of a construction start date for the Whitehorse, if as anticipated, your certificate and other approvals get issued, as you hope?

A. MR. MURCHISON: Madam Chair, we would need one construction season with -- as I noted before with us having the -- all the equipment in place for that site, so one construction season.

It's tight, but we have shown that we can do that and we did do that in Mayo, one construction season for the site as I previously noted. Thank you.

Q. So when you say one construction season, what year are we talking about?

A. MR. MURCHISON: Yeah, Madam Chair, that's 2027.

Q. 2027, and what's considered sort of a construction season? Are we talking April to October, just to give me an idea, Mr. Murchison?

A. MR. MURCHISON: Yeah, thank you. Madam Chair, Yukon construction season often starts after the May

long weekend but with a site like this, depending on when all approvals are in place, if we can start earlier, we will start earlier, of course.

Q. Thank you. Now I'm going to continue my questions in relation to some of the major projects that YEC has identified, and that would start coming into YEC's rate base over the next several years.

Now, you'll see I provided your counsel with an Aid to Questioning Number 13. If we can distribute that, and that will -- that shows the projects we're interested in with these -- in relation to the questions that I have.

So you'll see that there's a list of projects that have been identified, and there's eight of them, and using the information set out above in that table, it shows a total of 529.45 million and change. Now, I'll refer to these as "The Big Eight" just for ease of reference.

Now, and would you accept subject to check that that's the total amount of those projects that are listed?

A. **MR. EPP: Subject to check, we can confirm that the total of those specific items listed there does add up to 529, noting however that the project total for the Whitehorse Power Centres project is only**

again phase 1 and 2.

Q. Thank you. Now, in relation to these projects, I want to take the discussion now, and if you can look at, now we'll look at Cross Aid 14, and it's a discussion on cost estimates that I'm hoping to have with you. And that Cross Aid 14 is entitled "Emerald Group Webpage for Cost Estimates Types Guide."

Now, when we looked at the application for this GRA, we did a word search for terms such as Class 5, Class 4, Class 3, Class 2 and Class 1, and we mainly got results on the search for Class 5, Class 4 and Class 3 projects, but no references to Class 2 or Class 1. Would you accept that subject to check?

A. MR. MURCHISON: Yes, Madam Chair, I would accept that subject to check.

Q. Thank you. Now, the purpose of this discussion is to try to understand YEC's specific regime for creating project cost estimates of a specific class like a Class 5 or 4 or 3 broadly speaking, similar to the regime described in that Emerald Group questioning, Aid to Questioning Number 14.

So would you say that YEC's regime would have substantial differences in the details from the regime described? And we're talking about cost estimates -- in the regime described in the Aid to Questioning

Number 14, or is YEC's regime generally similar to cost estimate classes or stages regime described in that aid to questioning?

A. **MR. MURCHISON: Yeah, thank you, Madam Chair. What I'll do is maybe just to -- I'll describe what our regime is and then just rather than saying generally, I'll just give the numbers.**

So we report to our board and part of our reporting to our board for our large capital projects is where we're at with those projects. So generally similar to what you -- what was provided, we have a Class 5 estimate, which we would describe as minus 50 to 100 percent prefeasibility planning, very high level.

Then we go to Class 4, minus 30 to plus 50, and that would be feasibility and studies. And then Class 3, minus 10 percent to plus 30 percent on the engineering side preliminary and the planning side of things, studies and project proposal.

Class 2, minus 5 to plus 20 percent, we're in a detailed engineering or assessment phase. And then for Class 1, project construction or permitting for a project. Now, we use that sort of to report consistently to our board.

When we go out to consultants to undertake

estimates for us, I'd say we most commonly find the estimates coming back from our consultants are estimates that are completed using sort of the guidance, the standard from the Association For the Advancement of Cost Engineering, so that's what we find say a Stantec estimate, they are typically referencing that standard or other consultants that we work with.

So I would say generally what we have, it aligns with what you provided as a reference document for us.

Q. And so just so I understand that comment about the estimates from the consultants, what standards would they be using?

A. MR. MURCHISON: Paul Murchison, Madam Chair. We don't necessarily dictate the standard that the consultant would use. So I would say the most common standard that we see being used is from the Association for the Advancement of Cost Engineering.

Q. Thank you. Now, you've given me the variations for the different plus or minus the different classes, so thank you for that.

Now, what is YEC's view as to the general purpose of the cost estimates at each stage? So for example, you start off having estimates for a project, let's say it's a Class 5. But then as you move along, how are those refined or are they refined, and do you prepare

changes and I'm not talking just GRA, I'm talking even before coming to the Board with estimates and projects?

A. **MR. MURCHISON: Now Madam Chair, Paul Murchison. Yes, we do advance cost estimates, so maybe -- I'll use one -- an example of one of the projects that we're currently advancing through the cost estimating phases, and I'll speak specifically to the Mayo slope, which is currently under construction, and so when the Mayo slope, we initially had a failure of the Mayo slope that's going -- I say official initially, initially when I started with YEC. I started with YEC in August of 2022, and at the end of the month the slope failed and impacted the back of our plant at the bottom of the slope in Mayo.**

So we initially -- we decided how do we move forward, so we initially developed a Class 5. Now that Class 5 was advanced to a more refined estimate. So we worked with consultants to undertake a multiple accounts analysis that looked at various options to stabilize the slope. We essentially had very high level cost estimates for those, Class 5 cost estimate but in looking at that, we look at the most sort of the best out of those options.

You then further advance a couple options to a more refined cost estimate, and so say a Class 3 then

to make a decision on which estimate to advance further to go to procurement and tender it. In that case we went from essentially through a design bid build process. We chose the option, we used a consultant to design the slope, we tendered the slope and put it to market. And at the stage right now it's under construction, we describe that at being at a Class 1.

Q. So then for cost estimate purposes then you move down the classes, if I understood you correctly, and the cost estimates become more definitive, if I can put it that way.

For example, if I started off as a Class 3 and when it goes to a Class 1, the costs should be more certainly?

A. **MR. MURCHISON: Yes, Madam Chair, we generally look to have more certainty around the costs as we -- as the estimates become more refined and we move down through the classes from a Class 5 to a Class 1, and so and certainly what we see coming out of those estimates is depending on the type of project, varying levels of accuracy. Right?**

So it's not -- a Class 3 doesn't always land within that Class 3 range, so there is certainly variations that we see as estimates advance and this is really is what we look at our large projects that are

taking a more structured approach.

In an example where we might just be purchasing a smaller piece of equipment that's not that expensive, the project manager might just call a number of vendors and get prices and pick the lowest price. So he'd go immediately to a Class 1, not go through the whole process.

Q. So does YEC have a document that describes what you've just told me, or how does the process flow? Like, what is the understanding of different employees who are dealing with or consultants who are dealing with these cost estimates, if there is no document?

A. MR. MURCHISON: Yeah, thank you, Madam Chair. For employees that we have working on the larger more complex projects, we have a combination of say certifications for those individuals.

So our project managers go through a process to become PMP professionals, so they're guided by the Project Management Institute guidelines, so we do have sort of a foundation and individuals that have appropriate training and then certification or professional designation as it relates to project management. So that's -- that would be foundational for us in having those individuals go through that process and those are the individuals that oversee

these large projects.

For our consultants, I would say we don't dictate a guideline to them and, we rely on them to use their expertise and if they were to use a different say system to estimate a cost, as long as it's a standard system that generally aligns with ours, we would accept that.

Q. Now, Mr. Murchison, I understand that there is no one -- no guiding document, if I can put it that way, however, is there a summary that could for the Board, that could explain what you've just said in the record but in a bit more detail, which would give the range of the variations which you've said for a typical project development stages that correspond to each of the classes.

So as you've said, you know, it may start as a 5 and go down to a 3 and then and so forth, and that the general purpose of the cost estimate at each stage of a project, and then the information that YEC decision-maker then need before cost estimate moves to a lower stage can be prepared.

So for example, if you're moving a project from a Class 4 to a Class 3 or a 5 to a 4, so I guess what -- not I guess. I know what I'm looking for, is there some type of summary document you could provide the

Board on how these cost estimates for especially large projects work and how YEC works with them and advances then the different cost stages?

A. MR. MURCHISON: Yeah, thank you, Madam Chair. I'll happily take that as an undertaking.

UNDERTAKING - TO PROVIDE A SUMMARY DOCUMENT ON HOW YEC COST ESTIMATES FOR ESPECIALLY LARGE PROJECTS WORK AND HOW YEC WORKS WITH THEM AND ADVANCES THEM THROUGH THE DIFFERENT COST STAGES, CLASSES 1 TO 5

Q. MS. BENTIVEGNA: Thank you.

MS. BENTIVEGNA: Madam Chair, if this -- if we can first mark those two 13 -- the Aid to Questioning 13 and 14 as hearing exhibits, and then maybe if we can -- it would be a good time to break for the -- my questions.

THE CHAIR: Very well. That would be Exhibits 21 and 22, I believe.

EXHIBIT 21 - AID TO QUESTIONING 13

EXHIBIT 22 - AID TO QUESTIONING 14

THE CHAIR: Thank you. As indicated, I'll take a break now. Thank you.

THE CLERK: Order. This hearing will stand adjourned for 20 minutes.

(ADJOURNMENT)

THE CLERK: Order. This hearing is reconvened. Please be seated.

THE CHAIR: Ms. Bentivegna, when you're ready.

MS. BENTIVEGNA: Thank you, Madam Chair.

Q. MS. BENTIVEGNA: I'd like to continue with this discussion of different classes of cost estimates, and going to that Aid to Questioning 14, the PDF page 5 of that, where you see a description of a Class 2 that is referred to as a control estimate and a definitive estimate Class 1.

Now, if you can think about YEC's cost estimate classification or classes of regime and thinking in particular of the big eight project, that listing that was provided to you, so has YEC either prepared or does YEC expect to prepare for each of those eight projects a cost estimate that is intended to be a baseline estimate to keep track of costs after all major construction contracts have been signed and at the point at which YEC is ready to give the word to its project employees and contractors to actually start building the project?

A. MR. MURCHISON: Madam Chair, would you just be able to ask that question again, to make sure I fully understand it.

Q. Oh, certainly. In looking at that listing of eight projects, my question is whether YEC has prepared or intends to prepare for these projects a cost estimate that it would intend to be a baseline estimate to keep track of costs after all major construction contracts had been signed and YEC is ready to give the go-ahead for construction to start?

A. MR. MURCHISON: Thank you. Madam Chair, Paul Murchison. Maybe in the question the one point that I would just like to clarify is contracts signed. Let's say within the Class 2 we would be having those and having the estimates there and then the contract signing would take us to Class 1 because you would be setting the price, so just that slight clarification I think is how I would understand it.

Would that be correct?

Q. Yes.

A. MR. MURCHISON: Thank you, Madam Chair. So in those big eight projects, projects that we will need to advance to Class 2 prior to closing contracts and actually being, I would say, in the construction phase, you know, actually executing the construction, we will be doing that for -- should we proceed with the Wareham Dam spillway as a tunnel and spillway, those estimates would be further advanced.

Whitehorse Power Centre estimates will be further advanced, as well as the MHO plant.

Q. So, Mr. Murchison, you mentioned the Wareham tunnel project, but what about those other projects? So when does YEC do those cost estimates, let's -- so I'm looking for -- for all eight of those projects, where and when would these Class 2 and Class 1 estimates be done?

A. MR. MURCHISON: Thank you, Madam Chair. Maybe I'll start at the top of the list then, and maybe this will be helpful just to describe where we're currently at right now, and then that may help with subsequent questioning.

So for the thermal replacement for the battery energy storage system, for the surge chamber and for the rock slope, we would consider all those to be a Class 1 contract's fully executed, construction is underway, so those projects are in that stage where we are essentially close to completion on some of those as well.

The Wareham Dam spillway tunnel and spillway, we have essentially between those projects a Class 3 estimate. The Whitehorse Power Centre we're describing as Class 5, and the MHO plant, we've done some work on that with the KGS and that would be considered to be at

a Class 4.

So as those projects advance, as we get closer to construction, then those estimates would be further refined to let's say a Class 2 prior to moving contracts into place for those projects.

Q. So, Mr. Murchison, if you could confirm or clarify that for each of those projects, you've mentioned there is Class 1 for some of them, cost estimates, but that will YEC then progress the cost estimates for those that are still at a Class 5, will that progress to a Class 2 or Class 1 before -- so that there's a baseline before actual construction, a baseline estimate, is what I'm referring to.

Did I understand you correctly or please clarify?

A. MR. MURCHISON: Yes, Madam Chair. Madam Chair, yes. I would say we -- with that again that's just that point that the Class 1 would be the cost after the construction contracts are executed for those. So advancing Class 2, executing contracts, putting us into a Class 1.

Q. So could I ask you to undertake to provide us with a table for each of those eight projects identified that has the name of each project, the cost estimate used, and so where I guess which class it's at in the variation, the plus or minus range of the estimate,

depending on what class it is at, at this point.

And just to clarify, it would correspond to that -- that information I'm asking from you should correspond with the projects that are currently expected to be completed before the end of 2027, the test period, or that are on PDF page 7 of Exhibit 2-A.

Again, either they're going to be in service in 2027 or subsequently.

A. **MR. MURCHISON: As a followup, Madam Chair, just for clarity on which projects, it's not just the big eight? It's a larger list? So I just want to fully understand the list of projects that you're interested in. Thank you.**

Q. Mr. Murchison, to clarify, what we're looking for is just the -- what we've termed as the eight projects that are on the table, and all we're looking for is the class of estimate that that particular project is at and the range that goes with that class estimate in relation to the cross aid we've talked about, the list of the project and our whole discussion about how you classify projects?

A. **MR. MURCHISON: Yeah, thank you, Madam Chair. So we'll take as an undertaking for the big eight projects listed, the class, but then as I'm understanding it, the class as it relates to Aid to Cross 14**

specifically, so that estimate range, not a -- so we'll use that estimate range and put in there? Okay. Thank you.

Q. Yes. Thank you.

UNDERTAKING - TO PROVIDE THE LIST OF BIG EIGHT PROJECTS INCLUDING WHAT CLASS THEY ARE EACH AT AS IT RELATES TO AID TO CROSS 14

A. MR. EPP: Madam Chair, if I could just -- I'm not sure exactly where this questioning will be going, but maybe I'll take it to a higher level for a second and it seems to me like we're asking about the credibility of the Yukon Energy forecasting, and I would refer the Board back to actually the 2021 general rate application where the Board had that more specific question, and we had an information request, and it was YUB-YEC-1-48, and it looked -- asked us to look at all -- all major capital projects from 2008 onwards, and I mean there's always going to be scope changes in projects, but what the actual -- the response there showed that actual major project costs were 100.6 percent of forecasted rate base costs, so it showed very close alignment of the major projects from 2008 to 2021.

Q. MS. BENTIVEGNA: Thank you for that information,

Mr. Epp, but what we're trying to do is not necessarily test the accuracy of the forecast, but it's to look at what classes and what the range of the cost estimates are for these projects at this time, and so then going forward there would be at least a baseline or some information in relation to these big projects.

A. MR. EPP: Okay.

Q. Now, if we can turn to YUB-YEC-71 in -- that's Exhibit 4, PDF pages 466 to 468, and the question was: (as read)

> "Please provide a complete description of YEC's practice for determining contingency allowance forecast in its capital project budgets."

And that's at PDF page 467. And the response as you'll see is: (as read)

> "For projects above 2 million, the level at which projects require Yukon Energy Board approval, Yukon Energy establishes the contingency allowance through a structured risk identification project."

And then there's a couple more sentences after that.

Now, in what I've just referred you to, that response identified projects for question where -- from

business cases, costs forecasts -- sorry, there was a contingency allowance line item, but what I understand is that all projects for which the expected cost of at least 2 million, YEC follows what it calls a structured risk identification process for which YEC identifies specific risks and then quantifies the dollar value of potential cost impact for one of the identified risks; is that correct?

A. MR. MURCHISON: Yes, Madam Chair. It's correct that -- just to make sure that -- I'll say it back to you maybe for -- just to help out, to make sure that I understood it correctly, but we would identify a risk, put a cost to that risk, apply a likelihood to that risk and that would give us sort of the estimated cost of that risk, based on a likelihood of the risk occurring.

Q. So say that YEC has identified five different risks from -- that relate to a larger $2 million project or larger than 2 million. Now, and then there's an estimate financial impact for each one of those risks.

How is the total contingency allowance for those type of projects set, considering let's say you have five risk factors?

A. MR. MURCHISON: Thank you, Madam Chair. For the -- for an individual project, if there would be

multiple risks identified, individual costs associated with each of those risks, then a likelihood for each of those individual risk -- individual risks to occur, giving a -- so say it's a likelihood of 50 percent, half of the value of the risk would be of that specific risk would be applied, and then the cumulative value of those risks would be added up for that specific project, that's then added to the overall project budget.

Then if you look at say multiple projects, they each have their own individual risk contingency.

Q. Could you give an example, Mr. Murchison, looking at PDF page 466 of that IR response of the contingency allowance for one of the larger projects.

So starting with, just to be helpful, I'm looking for an example of a risk register document, one of the larger projects that has a contingency allowance attached to it, that you can give us as an example?

A. MR. MURCHISON: Yeah, certainly. We'd be happy to provide it as an undertaking, just to do that for you.

UNDERTAKING - TO PROVIDE AN EXAMPLE OF A RISK REGISTER DOCUMENT FOR ONE OF THE LARGER PROJECTS THAT HAS A CONTINGENCY ALLOWANCE ATTACHED TO IT

Q. MS. BENTIVEGNA: Thank you.

Now, I want to followup with what YEC and try to understand what YEC's practice is for drawing down the contingency allowance that's been set up for a project. And this is the subject of 71C, and that question is on PDF page 467, and the -- so YEC was asked to confirm about the drawdown, and the response is at PDF page 468, that response to C, that it wasn't confirmed and that: (as read)

> "Project contingency allowances are accessed when the pre-identified risk from the risk register materializes."

Now, using a hypothetical, suppose the purpose -- suppose that the purpose of a project where you're tracking as a specific project cost line item, the cost charged by a specific type of contractor, so that if in the normal course where there is no risk event, the charges paid to the contractor would be paid and recorded to the line item for the project to track the contractor's cost.

Now, if we were to add the risk event twist, say that a risk event occurs for a cost that's paid to the same contractor, now, I don't want to complicate it too much, but you know, I'm not asking about allocating an invoice between normal course billing and billing related specific -- with the cost of a risk event, but what I'm referring to is an invoice from the contractor that is

only a risk event cost.

Would the actual amount that YEC has deemed to be related to the risk event and that risk event cost would end up on a contingency line of the schedule that tracks the overall project, but no amount of contractors charges that are deemed to be part of the risk event costs would be charged to the contractor's line item.

I know it's a very long example, so if you don't follow me, I'd be happy to try to summarize it.

A. MR. MURCHISON: Madam Chair, I believe I follow it, and I believe I have an answer, but feel free to ask more questions if I'm not on the right track.

What I would say is the contingency allowance that we establish is not part of the contractor's contract, so it would be outside of that, so we would -- we track -- we would track that contingency allowance separate.

So now if there is a change to a contract that -- that could initiate -- result in a change order, a change order may or may not be attributed to a risk that was pre-identified. The contractor wouldn't be aware of that. That's, you know, our internal tracking as it relates to the contingency and the contingency drawdown say versus a change order that was for something that wasn't previously identified. Because

we're not perfect.

We don't identify absolutely every risk that could occur, so something may happen that we didn't identify. Now, our normal practice and what we try to do is if a risk materializes that was tracked as a part of the contingency, that would be part of the contingency drawdown. Something separate that was executed say through a change order, a decision to execute through a change order to the contract would not be shown as a contingency drawdown. I hope that's the clarity that you needed. Thank you.

Q. Yes. Thank you. So now going on to where a project is expected to cost more than 2 million, so we'll -- that's the class of project we're talking about, that has a contingency allowance based on assessed risk and consequential costs related to specific risks built into the project cost forecast, but none of the risks have been identified, none of the risks identified in the risk register for the project have materialized.

In that scenario, the final actual contingency allowance line item in YEC's schedule tracking of final actual costs would be zero; is that correct?

A. **MR. MURCHISON: So the -- Madam Chair, so if a -- on a construction projects if the contingency, if there's been no risks identified in the contingency,**

the contingency that we've had set aside is not drawn down, then that portion of the identified budget would not be shown as utilized, so it would be -- if say we had a $2 million project or -- and there was a $100,000 of contingency, risk contingency for our construction projects, that line item would stay as $100,000 if it was not drawn down, if that's what you're asking.

Q. Thank you. Now, continuing along the line of contingency allowance and risk registers. Now, we were discussing project cost estimates earlier, at various stages of a project life cycle.

So for example, your business case for the Wareham Dam spillway tunnel project at PDF page 269 of your application talks about a Class 3 estimate, and provides a range of variances in brackets that run from minus 20 percent to plus 30 percent.

Now, our discussion before we talked about where the tender process has been completed and all contracts have been awarded and signed, so that the estimate is just before the construction starts, and suppose -- and for the purposes of my question, suppose there's a revised contingency allowance estimate reflecting only the risks that would still be a concern, no risks higher than the forecast tenders, for example.

Now, in this example is -- if none of the

remaining risks reflected in the contingency allowance for the just before construction start estimate actually materializes, should a total project final cost that falls above the part of this preconstruction phase forecast that reflects only the bare bones but not the contingency allowance part to be above forecast or not.

In other words, shouldn't the contingency allowance be removed from a forecast versus actual comparison if the risk that the contingency allowance was built on -- didn't occur?

A. **MR. MURCHISON: Yes, Madam Chair, there was a fair bit there. So if you could repeat just to give us clarity on the exact question again, that would be helpful. Thank you.**

Q. Certainly. Now, I'm starting with the supposition for this question that there's a revised contingency allowance estimate reflecting only the risks that would still be a concern, so you're ready to construct, but that -- there's still a contingency allowance. And so, for example, there's no risks of higher than forecast tenders, for example, because they've already been done.

Now, in this example, if none of the remaining risks reflected in the contingency allowance for the --

just before the construction start estimate actually materialize, should the total project final cost that falls above the part of this preconstruction phase forecast that only reflects the bare bones, but not the contingency allowance to be part of the above forecast or not?

So I guess what I'm looking at is, what would the contingency allowance, whether it be removed from a forecast or not, if it would still continue in the forecast, even though you're at that stage where it -- you're going to build, and the basis for the contingency allowance, the risks, didn't occur?

A. **MR. MURCHISON: Madam Chair, I think I'll -- I think I understand, and I will again maybe I'll describe a description, then answer it as I'm understanding it.**

So we have our -- you know, referencing -- that reference on page 269, you know, indicating a Class 3 cost estimate of minus 20 to plus 30 percent, so we are advancing that and we have moved into Class 1 with contracts executed and the question now we're at that stage, should we no longer have a contingency because I think the question is the risks we don't have -- those risks have been managed and maybe those risks don't exist anymore.

The answer would be no, because even at a Class 1 in all the estimate models, there still is a variation that's provided, potential plus or minus variation, so there's things that can happen say and thinking about construction specifically that can cause additional costs to be incurred that there's a risk for, so if you -- if we -- on a tunnel project, for example, or advancing that, you have a geotechnical investigation that doesn't have complete details on all the geotechnical conditions.

An unforeseen geotechnical event could occur that may be covered by a risk contingency that you evaluate even after you've awarded the contract, so there's a potential, just in that example a change that you might identify in a risk contingency, that's even part of, you know, the phase in Class 1 as you're executing the contract.

Q. Thank you. Now, if you could go to Appendix 5.2A-3, which is YEC's business case for the MGS water use licence renewal process and it's at PDF pages 396 to 406 of the application, which is Exhibit 1-A.

Now, the business case refers to a stagegate budgeting and decision-making process. And I'm primarily interested in the paragraphs immediately under the heading "Project Approach," which is found at

PDF page 399 of the application and you'll see it starts as "stagegate framework approach was used for undertaking the project" and so forth.

Now, the MGS water licence renewal project has a budget, which is perhaps only reflective of forecast expenditures at the time of the application, and that was 7.295 to round off million, but I'm wondering whether since all of the big eight projects have a budget much higher than this, the budget of the surge chamber replacement project, for example, has a budget of 27 million and upwards of more than 27 million.

Would all of the big eight, what I refer to as the big eight, those projects that were on the list, on the aid to cross I gave you, also be subject to a similar stagegate process or not?

A. **MR. MURCHISON: So, Madam Chair, on page 399, the stages from project initiation Stage 0 through to Stage 4 permitting applied to those regulatory projects as well as projects that would be going through the permitting process to move to construction.**

Q. Now, does YEC have some kind of basic document that is used to explain the stagegate decision-making process within YEC, say for YEC board members that may not have encountered that approach before service on YEC board or that -- so that could be shared with this Board, if

you have such a document.

A. **MR. MURCHISON: Madam Chair, we don't have a specific document.**

Q. So I'm to take it from your answer that then you would, for each project that you would take forward, you would be preparing an explanation for let's say your board?

A. **MR. MURCHISON: Yes, when we report to our board to initiate a project, so the 2 million and greater project, there's the initiation of a project then the quarterly reporting to our board on the project as it progresses.**

Q. Thank you. Now, we've talked about YEC's internal processes for estimating costs for managing major construction projects, and we've talked about the different types of class cost estimates at typical points in the project development, how YEC evaluates risk and how much risk is built into the contingency allowance, and YEC makes decisions about whether it's reasonable to advance to different stages in the lifecycle of a project, stagegates.

So thinking about this, what we've been discussing, and thinking ahead to the fact that when YEC files its next GRA in 2028, which are like to include some big -- some of those big projects that we've listed, at that time, the Board will have to --

this Board will have to assess the prudence of YEC's final costs.

Now, is anything you can think of now related to how YEC manages and oversees its major projects that YEC is prepared to consider adding to the information that it currently provides in its GRA in defence of the prudence of its final project expenditures?

A. MR. EPP: Madam Chair, just a question of clarity. Are you referring to things we could do differently in the next GRA to make it easier for the Board to review?

Q. Yes.

A. MR. EPP: So yes. I mean, as we've been going throughout this process, I think we've all been keeping track of a lessons learned and how to avoid questions in the future by providing the information more upfront, and while we haven't had this discussion yet as a group as far as what specifically we're going to do in the next application, I generally have on my list some -- without getting into specifics yet because it hasn't been thought about completely but some kind of schedule that tracks this is what the approved cost was in the last general rate application, this is what the actual costs of the project as they existed when they were finalized, and then have a variance analysis

for those projects, and that would be sort of a starting base. But that was just my idea without consultation.

Q. All right. And maybe if I can suggest we had that whole discussion on project IDs and tracking, if -- it would be very useful, if there could be a system, a consistent system, and maybe there is. I'm just saying we don't know about it, the Board doesn't, of how they're identified, named, and tracked, if they're continuing as another or as part of another project. I'm just referring you to that discussion we had.

A. MR. EPP: Yeah, that is helpful. We're always open to recommendations for improvement.

Q. Thank you. Now, this is seeking clarification between an owner's engineer and a project manager function, so if you go to Exhibit 4, the response to YUB-72, that's at PDF page 469, and then the application, Exhibit 1-A at PDF pages 243 to 254 and I'm going to be referring specifically to Table 5.1A-7 at PDF 249.

So now starting with that response on PDF page 469, that response to IR-72, Board IR, and there you describe the different roles and -- but I still have some questions about the role, as I was just mentioning, of the owner's engineer and the project manager in the context so that we can better understand

the project -- of the BESS project.

So for that project, there's both a project manager and an owner's engineer, and what I'm looking for when I look at Table 5.1A-7 at page 249 as I mentioned of the application, so you'll see there the descriptions and costs of the different categories.

Now, the BESS project also has a line item for an EPC contractor, and I'm wondering, if in that project, if the EPC contractor were to account -- a change in circumstances while constructing the project and wanted an adjustment to the contract to compensate the EPC contractor for having to deal with some new circumstance encountered in the course of constructing the project, is it the owner's engineer or the project manager or perhaps both that assess the EPC's contractor request for a contract adjustment.

So I'm just trying to see how the roles are defined within YEC of these different positions.

A. **MR. MURCHISON: Yeah, thank you, Madam Chair. So in a scenario like this, we'll say using this -- using the example that you've described, the -- if there was typically if there's a change that would occur and the contractor would be notifying us of that change, it would go to the project manager.**

If there was a technical evaluation of that change

required, then the owner's engineer would take a look at that.

Q. Okay. So the request would go to the project manager, who would then consult also with the owner's engineer, and the owner's engineer would be representing YEC?

Do I have that correct, as is the project manager.

A. MR. MURCHISON: Yeah, thank you, Madam Chair. If there was technical information, so the owner's engineer, say in the battery project, for example, that supports our team technically, so engineers that have experience and understanding of battery energy storage systems, someone that has experience that's not on our team.

So if there was a change that came in and it needed to be evaluated from an engineering technical perspective and we, with our team, would not understand how to evaluate that, then we would certainly go to the owner's engineer to ask them for advice on how to manage that change.

Q. Thank you. Now, at that table, that 5.1A, A-7, at PDF page 249 that we were just looking at in the application, there's also both a line for YEC internal labour and project management.

So does this mean that in respect of the BESS project, the project management function is also

performed by an external contractor rather than a YEC employee?

A. MR. MURCHISON: Yeah, thank you, Madam Chair. So I'll actually -- to answer this question I have to step back in time a little bit. So when I joined Yukon Energy in -- at -- in August of 2022, there was no one within our organization to manage the BESS project.

So we -- the engineering and capital projects team has grown since then, so when I joined Yukon Energy, we had an external project manager that consulted through Hatch that was serving that project management role.

We've since recruited a senior project manager that now leads the project management activities on this project with occasional support from that Hatch project manager.

We still continue to rely on the engineering expertise of Hatch, so they were providing both services for us and continue to, so that's -- that's -- there's been a change on this project over time based on the increased capacity within our organization to manage projects.

Q. Thank you. Now, looking at those eight projects that I've referred you to, would there be a project manager that would, in the various projects, would there be a contract project manager or would it also -- or would

it also go to it being managed by -- internally by a YEC employee?

And it may vary, so if you can just give me your views on who you think would be -- whether it's an internal resource or a consultant.

A. **MR. MURCHISON: Thank you. Thank you, Madam Chair. So what I'll do is I'll run through the projects, so on -- and then just speak specifically to project management internal or external or maybe a combination of both in those cases.**

So thermal replacement project is currently managed by an internal project manager. The battery energy storage sytem we just discussed, the MH0 surge chamber and MH0 rock slide stabilization and remediation, the project management of that is led by an internal project manager with some support from an external senior project manager, and that's just -- it's a large complex project, so that's just in case our internal PM needs a bit of extra support having someone that she can rely on for back up.

Now, we foresee as we move forward with the Wareham Dam spillway tunnel and Wareham Dam spillway full replacement, we have an external PM currently leading that project with some internal support from our team.

The Whitehorse Power Centres, we have external support advancing that project right now.

And the Mayo MHO plant renewal, we've done work on this. We have kept that internal to an PM. But as that advances, if we need external support, we would look to that. But right now I can't say exactly where that's going to go. It will depend upon the available capacity within our project management team.

Q. Thank you. And since you've just mentioned that, you know, some of those projects will have external project managers or consultants, at a high level, can you explain how YEC contracts with an external project manager, how it structures its contracts to incent or assure that change orders that may be requested by a major contractor on a specific project will be reasonably scrutinized and will be, where warranted denied.

So I'm looking to see what kind of -- if not specific language, but what you may include in a contract in relation to how the project is managed, really, when it comes to change orders or any other changes to the project?

A. **MR. MURCHISON: Yeah, thank you. Madam Chair, I guess maybe the final approval of the change order doesn't lie with, say, an external project manager, so**

they would -- they would recommend accepting or not accepting, but the final determination about acceptance of a change order sits with Yukon Energy so, and depending upon the size of the change order, different levels within the organization.

So I think that that -- so I don't have any specific language from a contract that I could reference, other than that an external PM does not have the authority to approve an expense. It has to be approved within Yukon Energy.

Q. Thank you for that clarification. Now, with -- I'm moving on to the MH0 surge chamber replacement project described in section 5.1A-5 of the application starting at PDF page 272, and it's described that there's a phase 2, as the plunge pool that's being referred to there.

Now, can you confirm that this schedule for the plunge pool part of the project has not been affected by the issues that are affecting the expected timing for completion of the tunnel project, and again, I'm referring to the surge -- MH0 surge chamber replacement?

A. MR. MURCHISON: Madam Chair, the surge -- maybe just so I'm -- the surge chamber construction is not impacted by a plunge pool construction. Plunge pool

construction is separate from the surge chamber and is associated with the replacement of the Wareham Dam spillway.

Q. Thank you. Now, if -- now I'm referring to the October 14th letter from YEC, and in that first paragraph, there's a sentence -- it's the second page of the letter, but I'm referring to the first paragraph there, which starts with: (as read)

> "As the project schedule is progressing, Yukon Energy is facing some challenges and opportunities with the spillway design. This includes the possibility of pursuing an alternate option of an open channel design instead of the tunnel option described as option 7 in the GRA at PDF page 269."

And it goes on.

Now, can you elaborate on what challenges and opportunities within the spillway design are being referred to here?

A. **MR. MURCHISON: Yes, so Madam Chair, the spillway project I would -- you know, and as we've been talking about sort of advancing projects, this has -- project has advanced a bit differently because we're dealing**

with engineering reports in both December of 2024 as well as this year indicating to us that there's the potential for the spillway to fail, and really what that means is that you flood the Mayo -- the community of Mayo in the event of a failure, and there's significant environmental impacts that could occur, so we've been working to advance this project in an expedited way.

Now, the comment that we have as it relates to challenges and opportunities. One of the challenges that we've experienced as we've advanced, coming from the multiple accounts analysis and moving to the option to select the design of a tunnel and replacing the existing spillway, as those cost estimates have advanced further, we've seen cost increases, so that's a challenge for us.

It's also challenging to try to advance on the timelines that we are advancing on. So as we saw some of these costs starting to increase, we had our engineer of record, as well as our owner's engineer and an independent cost estimator that was working on the engineer of record's team indicating to us that we should engage a contractor that would actually build this to take a look at it and help us understand, you know, potentials to optimize and how to, you know, best

get some additional information, so in -- with that recommendation, we have Kiewit as a contractor working onsite, stabilizing the slope and replacing the surge chamber, and we know they have experience undertaking spillway work, like we're describing.

So we've engaged with Kiewit to take a look at the design, as it's advanced, and to indicate to us potential for optimization, you know, as it relates to schedule and cost, and certainly when they looked at the spillway, what they found was they proposed -- they're proposing an option as it relates to a tunnel where you could potentially eliminate the need for a coffer dam, $15 million. They indicated a potential to shorten the tunnel.

But what they also indicated to us was that, from a construction perspective, they believed that building a larger spillway where -- roughly where the tunnel is proposed may be a better option, and that would be from both a schedule and cost perspective. So Kiewit is doing some work to explore that option to give us a better understanding of whether that would be a preferred option, primarily to mitigate the risk that we're currently facing with this piece of infrastructure, but also considering, you know, the costs. So it's scheduling costs is what's really

driving this additional work that we're now doing with Kiewit essentially as a contractor to provide us with some information.

Now, prudency is also certainly critical and we are in the process of retaining our own independent cost advisor to make sure that, you know we get is something we can stand behind if we were to have information that would lead us to making a decision to change the option for construction.

Q. Thank you for that answer.

Now, the second paragraph on that second page of the October 14th letter, at the end of the paragraph YEC indicates that: (as read)

"The spillway would be available for the '28 spring freshet, that's indicating that the new in-service date for having an additional spillway in place is the second quarter of 2028."

Am I reading that correctly? At this time.

A. **MR. MURCHISON: Yes, Madam Chair. The anticipated spillway in-service date would be prior to spring freshet in 2028. We would be looking towards the end of Q1 prior to that event occurring.**

Q. Thank you. Now, going back to the first page of the letter, and looking at the last paragraph on that page,

and that's referring to the response to YUB-70, part C and D, which is in the Exhibit 4.

So YEC's response to part C included a project schedule for the tunnel project, and that begins at PDF page 458 of the IR, consolidated IRs, Exhibit 4.

Now, at the top of PDF page 458 of that exhibit, it indicates that the tunnel project schedule provided just below on the page as it existed at the time of the application.

So does that mean that the project schedule, as it existed in May of this year, that reference to, as it existed at the time of the application?

A. **MR. MURCHISON: Madam Chair, that this would have been the schedule that existed early in 2025, I believe.**

Q. Thank you. And now, would you be able to provide a project schedule as it exists as of September 30th, since you've advised the Board that the tunnel project won't be completed during the 2027 test year?

A. **MR. MURCHISON: Yes, Madam Chair, we do have an updated schedule that we can provide through an undertaking.**

UNDERTAKING - TO PROVIDE A PROJECT SCHEDULE AS IT EXISTS AS OF SEPTEMBER 30TH, SINCE YOU'VE ADVISED

THE BOARD THAT THE TUNNEL PROJECT WON'T BE COMPLETED DURING THE 2027 TEST YEAR

Q. MS. BENTIVEGNA: Thank you. Now going back to page 2 of the letter and looking at the third and second last paragraph, so the one that starts: (as read)

"Considering the significance of the tunnel project and its costs."

And so on the subject of cost estimates, could you go to your response to YUB-70, again looking at PDF page 459 of that IR response, and the budget for the tunnel project at PDF page 459 is approximately 74 million.

The lead-in to the table on that page indicates that the budget, which only has six separate line items was as it existed at the time of Yukon Energy's management made the corporate decision to commence substantial expenditures on the project.

So approximately what date was that, that YEC management made the decision to commence substantial expenditures on the project.

A. MR. MURCHISON: Madam Chair, so we recently had a board decision in August that is advancing significant expenditures.

Q. And that would be August of '25?

A. MR. MURCHISON: Yes, Madam Chair, that's correct.

Q. And then, so is it still your view that the IR response that the forecast final cost of about 73.9 or 74 million still holds?

A. MR. MURCHISON: Madam Chair, no, that does not hold for the tunnel replacement option; as I noted when you asked about some of the challenges, our updated estimate for the tunnel right now is sitting at 93.6 million.

Q. And I believe correctly if I'm wrong that we'll get -- that you've undertook to give us an updated budget for the tunnel; is that correct?

A. MR. MURCHISON: Yeah, thanks, Madam Chair, we undertook to provide an updated schedule.

Q. Okay. All right. Then how about an updated budget as well?

A. MR. MURCHISON: Thank you, Madam Chair. So what we can provide is an updated budget for the tunnel option; is that correct? That's what you'd like, correct?

Q. Yes. Since we were just discussing it and you mentioned that costs have changed, so.

A. MR. MURCHISON: So, yes, thank you, Madam Chair, we'll provide an updated budget for the tunnel option. Thank you.

UNDERTAKING - TO PROVIDE AN UPDATED

BUDGET FOR THE TUNNEL OPTION

Q. MS. BENTIVEGNA: Thank you. Now, the second to last paragraph of that letter, that October 14th letter, indicates that YEC anticipates providing an updated cost projection for phase 2 once the preferred alternative is confirmed.

So when are you thinking that YEC will be able to have an updated cost projection for phase 2?

A. MR. MURCHISON: Thank you, Madam Chair. We are in the process of doing -- as I noted with -- independently with a contractor looking at the option of an open channel spillway. We anticipate making a decision by the end of this calendar year as to whether or not we will continue to proceed with a tunnel and a -- with the construction of a tunnel and the replacement of the existing spillway or pivot to construction of an open channel option.

So in the event that we pivot to an open channel option, that's a different construction approach, and that would -- we would be advancing those cost estimates and that construction, if that was our decision.

Q. Thank you. Now, I have -- I'm moving off of the projects, and this is going back to get clarification on a point earlier in the hearing, and it relates to

when there was the discussion about the CAFN and the debenture, and so if you want the transcript volume page 107, line 19 to page 108, line 22, and so to build on that discussion, I have the following questions for clarification of what the rate the debenture is for rate making purposes.

So to start, and these are subject to check, these statements, but they shouldn't be controversial.

The CAFN debenture arose pursuant to Chapter 22 of the CAFN final agreement and was honoured as part of the AGS project agreement signed July 21, 2022, as is stated in YUB-54A at PDF page 327 of Exhibit 4. Is that correct? Is that subject to check?

A. MS. CUNHA: Yes, it is.

Q. Thank you. Then the BESS project proceeding occurred in 2021 with the Board issuing a report on June 30th, 2021, and as I go through these, if you have any issues with any of my statements, just please say so.

And then the YEC 2023/'24 GRA was filed August 31st, 2023, and in tab 7, Schedule 11, it forecast new debt at -- excuse me -- at 4.23 and did not include a line item for a CAFN debenture.

And that -- the YEC 2025/'27 GRA is the first time that the CAFN debenture is before the Board in a GRA setting, and that was -- that's found -- the reference

to it in the application, tab 7, Schedule 11.

Now, the cost of debt for the CAFN debenture in the YEC in the current GRA, tab 7, Schedule 11, calculates as follows: 2023, 3.8. 2024, 7 percent. 2025, 7.9. 2026, 9.2 and 2027, 9.2 and this is calculated as line 39 and line -- it's calculated from and line 15.

Now, in the current GRA forecast the debt is 4.55 percent, and that's from your application, PDF page 105, note 5.

Now, YEC stated in this GRA application that during the BESS part 3 hearing, Yukon Energy proposed that investment opportunities to be provided to the First Nations by structuring the debentures arrangements as a benefit where Yukon Energy pays the interest on debentures, based on the actual rate of return on equity, however, for rate-setting purposes, Yukon Energy will use the cost of debt to remove the impact on ratepayers.

The variance between the actual interest rate and the interest expense included in rates will be charged against Yukon Energy's retained earnings. The Board in its report dated June 30th, 2021, stated that it accepts Yukon Energy's commitment that ratepayers will not be adversely impacted by the debenture investment

opportunity.

Accordingly, the application assumes all new debt including any new debt related to First Nation debentures, with an interest rate of 4.55, which is based on the Bank of Canada benchmark plus 120 basis point.

So now, when we were discussing this on October 21st, it wasn't clear and maybe I can -- rather than going through the transcript, and I will if you need me to, is what is the answer to what the rate for rate-making purposes for the CAFN debenture being charged to rates? Is it the ROE rate or is it the 4.55?

A. MR. EPP: Madam Chair, I think I've got this question here. So for the specific CAFN debt of $1 million, I actually believe we have the interest cost included in this application at the ROE rate of 9.15 percent, so for that $1 million. New debt that would come into play in the '25 to '27 years for the rate making purposes is at -- there may be some of that that is part of First Nation agreements, but for rate-making purposes, that is all at the 4.55 percent.

Q. So then, Mr. Epp, if I understand you then, that 1 million for the CAFN is being charged in rates at 9.15?

A. MR. EPP: Sorry, I was not paying attention

there. Could you repeat your question?

Q. Sure. It's for -- I understand [indiscernible] debt we said in the '25/'27 test period that's at -- the interest on it is at 4.55. Okay.

But my question is -- seeing what was said in the BESS proceeding how ratepayers would not be impacted by debentures, and that -- that I just read you anyway, and I can reread it to you, if you need to.

My question is, is the CAFN debenture being charged to ratepayers at 9.5 percent or 4.5 percent and the rest of it being at a shareholder cost?

A. MR. EPP: The CAFN debt is being charged to ratepayers at 9.15 percent. The CAFN debt is not part of the BESS agreement. The BESS -- so there has actually been no agreements yet regarding BESS. The CAFN debt regarding the AH3 project.

Q. Okay. So the CAFN is regarding the AH3 project, if I understand you correctly, and that's being charged at 9.15?

A. MR. EPP: Correct.

Q. And what's the justification for that? Seeing that, you know, let's say once you do sign an agreement for BESS, it will be -- well, from what I understand at 4.5.

What's the justification for charging ratepayers

at the 9.5 debenture for the AH3 debt?

A. MR. EPP: There are two different projects. There was no specific guidance on how to treat CAFN debt to our understanding. It was the BESS debt.

Q. And do you agree that the Board didn't see the rate on this debenture until this GRA, that it wasn't presented in the '23/'24? And I mean, you can take that subject to check?

A. MR. EPP: Yeah, I'm not sure. I don't recall offhand whether the Board -- what the Board saw in the previous general rate applications.

Q. All right. If you wouldn't mind then checking to see when the Board, this Board, was made aware of the rate that's being paid on the CAFN debenture at 9.15 percent?

A. MR. EPP: Yes, absolutely.

UNDERTAKING - TO ADVISE WHEN THE YUKON UTILITIES BOARD WAS MADE AWARE OF THE RATE THAT'S BEING PAID ON THE CAFN DEBENTURE AT 9.15 PERCENT

Q. MS. BENTIVEGNA: Yes. Thank you.

MS. BENTIVEGNA: Madam Chair, those are my questions for now, and then I'll have questions on the net salvage.

THE CHAIR: Thank you, Ms. Bentivegna. And

I'm very aware that we have gone over for lunch, but I'm thinking that it would still be opportune, there are a few questions from the Board and to get those questions taken care of before we have our one-hour lunch break.

I believe, Mr. Johnson, you have some.

MR. JOHNSON: Sure, thank you, Chair.

MR. JOHNSON QUESTIONS THE PANEL:

Q. MR. JOHNSON: Couple clarification questions. The first clarification I'm going to relate to a part of a transcript from Tuesday's hearing, volume 1, October 21st, page 20, starting at line 9.

I'm going to tell you what the quote is, so if you want to take the time to look at it, you can, or you can just accept my word for it and check later. And the discussion at that point was there was a response to questions from Ms. Bentivegna regarding this spending reserve required for system stabilization associated with the IPPs and renewables, and Mr. Murchison, and I think you answered and this is a quote: (as read)

"So we have an increased spending reserve to 3.7 megawatts at an increased cost of $2 million in 2023, and then in 2024 increased to 4

megawatts at a cost of 2.2 million."

End quote.

So my question is that was the increase to 3.7 and 4 megawatts, if IPP and renewables had not been on the grid, what would the base level of -- or what would the level of base spending reserve have been, so I'm just looking for that incremental portion?

A. MR. MURCHISON: Yeah, thank you. So, Madam Chair, I'll just -- we -- high level, what we had in 2023 with a total spending reserve 6.7 megawatts, so spinning reserve without IPP micro gen 3 megawatts, an additional 3.7 on top of that.

And then for 2024 a total of 7 watts -- 7 megawatts, sorry, and then, so the system would have been 3 -- so that's an increase of 4 megawatts, and that's a rough estimate.

Q. That's great. Thank you. And I take it would be, just as a followup, it would be kind of proportional, so that additional spinning reserve would be proportional to the quantum of energy being put on the grid by IPPs and/or micro gen?

In other words, the more renewables put on, the higher the spinning reserve would be, kind of proportionate?

A. MR. MURCHISON: Yes, and as it relates to the load

on the grid as well.

Q. Right. Okay. Thank you. Second question in terms of following up and this has to do with the topic of the number of rented diesels through the test years. And looking kind of at the various parts of the application and follow-up on documentation, there has been a number of different factors brought up, so I just want to clarify that to make sure I've got it clear, and this goes back to the transcript again for October 21st, and it was starting at line 17 on page 78, and Mr. Epp, I think you were responding at that point to Ms. Bentivegna on the BESS in-service timing, so the quote was: (as read)

> "The intention of YEC is to have BESS in service in 2026. And I can refer you to NY-YEC-11, Attachment 1, where we will see the benefits and we have allocated to the BESS in the reduction of diesel rentals and BESS online."

End quote.

So in light of the fact that there are a number of factors identified that will influence the number of rentals that will be in place through the test years, so we've got BESS, you know, which will displace a certain number of rentals.

Now, looking like that's more 2028, but we'll have demand side management over a long period of time, that's 7 megawatts, mutual aid agreements, just what I'm looking for is a confirmation on the number of rental diesels through the test years, and the way I'm reading this, so maybe you just have to confirm this, that it's 22 rentals through '25, '26 and '27.

A. **MR. EPP: Mr. Johnson, the original application had 22 rentals in 2025, 2026 and 2027. With the -- so in YUB-YEC-1-8 we provided information about the Whitehorse Power Centre coming online, and assuming that comes online, the 2027 rentals would be reduced to 18.**

Q. Would that be for a good portion of 2027 or just that last month?

A. **MR. EPP: It would be -- the normal contract for the diesel rentals starts in December. I mean, November would be the commissioning period, but the rental period normally starts December of 2027.**

Q. Okay. So one of the factors is the rental agreement and the commitment, if you will, to the 22 diesels through to December 2027?

A. **MR. EPP: Yep.**

Q. Okay. Thank you. My last question before lunch, at least from me, would be, you know, we referenced a

comment that was made by the past Chair about who is going to pay for all of this at the beginning, and I think another key perspective obviously of ratepayers and the Board is so what are we actually going to pay for through the time period, and there's been a lot of discussion on that today with respect to a couple of large projects, particularly the Whitehorse Power Centre South, and Mr. Epp, we did hear what you said about the performance of YEC or actually I think it might have been Mr. Milner, about the performance of YEC in terms of forecast versus actuals over time, however, part of the concern is that we're really moving into a whole new era with unprecedented capital spend and commitment, and the world has changed, as we all know, kind of through, you know, since 2020 for sure, in terms of the entire environment surrounding getting projects done.

So my question really is, and it's kind of on behalf of the Board and for ratepayers, is, you know, what else can be done by YEC to reassure ratepayers and the Board on the prudency of the cost forecasts over time?

Right now, and I could pick any one of the projects, but looking at the Whitehorse Power Centre, there's an estimate there, it's a Class 4 estimate, I

believe, and a lot can happen between now and where we're going to be, further that project even as now and we heard very clearly it's schedule driven, and that quite often comes at the risk of cost, and potential equality as well.

So really we're just looking for kind of what YEC would propose in order to not only provide some confidence now for ratepayers and for the Board, but particularly over the next couple of years to really avoid the point where we get to where there's a large surprise by the next GRA in terms of where we're at with the costs, and of course, I've been referencing the Whitehorse Power Centre, but it goes beyond that.

I mean, you've got a lot of projects in the hopper so-to-speak, and how does YEC intend to communicate differently, and in terms of being able to manage those costs and manage and give confidence that the projects are being well-managed?

And I think Mr. Murchison, you identified a number of areas that do provide some of that reassurance. You know, long lead time materials and the different actions that are being taken, but I'm just looking for a bit more of that.

A. **MR. MILNER: Mr. Johnson, Madam Chair, I'll start with the higher level sort of introduction, and**

Mr. Murchison can speak to some of the details that I reference, but I think over the -- I think we can all agree that since the last time we were here before the Board, the pressure, global pressure, has not decreased. It's increased.

The intensity to build things faster, to all access different markets that everyone is trying to access at this time has increased at this time, and what that does is it drives uncertainty and it drives challenges, and I think the key actions that you're seeing Yukon Energy take right now around extra due diligence in order to respond in that context is a response to that exact piece.

So what we're having to do is change the way we do business fundamentally. We're having to access partners. We're having to lean on our neighbouring utilities, whether it be ATCO with extra purchasing power or BC Hydro with extra resources to respond to emergencies. That's becoming more and more commonplace right now.

So certainly the diligence increases -- is increasing at the same time that the urgency is escalating, and all of that points to tactics to manage uncertainty.

So some of the key changes in the way we do

business are accessing expertise to both confirm value, confirm cost. We're having to access very specialized expertise to manage projects that are just way outside of our in-house ability to manage, and, you know, I would draw -- you drew us to the Whitehorse Power Centre. I would draw -- we need to draw attention to the fact that the Mayo projects are incredibly complex, and we're having to build out a wall of talent to be able to respond to that, in both a rapid way, but also in a way that assigns the due diligence is required.

So that's what we're feeling and how we're responding to the overall landscape of things, and I can ask Paul to dig into some of the more detailed tactics if you wish or that was the kind of level of answer that you're looking for.

Q. I think that kind of addresses it from a very high level and globally, but I know that the Board and others will be looking for more than that.

Like, specifically, I mean you've undertaken projects in the past, and what lessons learned have been brought forward, and really how are you actually going to manage these and not sacrifice, you know, the other 70 projects that are or whatever number it is, number of other projects that you have underway, and I know I'm not representing something new here. It's a

daunting task for you, but the -- certainly the concern from the Board perspective is, you know, having confidence in the numbers that have been put forward?

A. MR. MILNER: Yeah, we can certainly appreciate that. And we're seeing the same level of inquiry at our own board meetings when we're reporting quarterly and annually on project. We've had to increase the overall focus on our committee level discussions, whether it be the project level committee and throughout the whole organization, so things are getting more scrutiny, more questions are being asked, more advanced planning is being required. The regulatory landscape is demanding that rigor as well.

Paul, do you want to speak to some of the more specific details to support those comments?

A. MR. MURCHISON: Yeah, thank you. And I guess reflecting a little bit, I mean, a lot of the questions today about prudency as it relates to how we do estimating, how we track contingencies, I think they are all important questions to ask us because we are spending more money. So yeah, I think that line of questioning was important.

And -- but I think in line with what Mr. Milner is saying, it's been quite challenging, and you look at some of these big projects in Mayo where you have a

slope failure and risk of spillway. Those projects have to happen and those projects have to advance.

What I can say in your comment about learning and how do we advance projects, I think if you look at projects, some of these big projects that are currently underway, thermal replacement, battery energy storage system, the surge chamber and the rockslope, although they're not easy projects, we talked about them being at Class 1, we have a -- you know, within those ranges, we have a high level of confidence that they will be delivered at, you know sort of in the price ranges that we're talking about here, but there is risk to the Wareham Dam spillway, for example, as we're advancing that quickly, and we're seeing as I noted some cost fluctuations, but then your question about the south power centre, I actually believe that that -- although not advanced cost estimate, given the recent thermal replacement work we've done, given the building of the Mayo facility, right, we actually are more confident in that estimate, you know, being pretty good, because we've done that type of work.

So part of what we have too is some repeatable work that's in our system, and that's -- you know, we built plants, we've built the infrastructure to support plants, so we have some of that experience. Whereas we

don't -- we rely much more heavily on consultants when it comes to building a spillway. We don't have internal people that have built a spillway, right, and there's lots of components there.

So I mean that's just -- I think with the numbers that you have in front of you now, some of those numbers are good, some of them as highlighted as some of those numbers are subject to potential for more change, but then I did want to highlight was that plant renewable being on track that I think we're getting those pretty good numbers there.

Q. So I would just caution that with the element of being schedule-driven, you know, it changes the dynamics of the project significantly, no matter how many times you've built it, but anyway, thank you for the comments.

A. MR. EPP: Mr. Johnson, the other thing that I hope will help is we do want to come back to you more frequently, for example, like applications for every year, whether like we've got three-year applications, so we probably will be providing a -- the plan is provide a new application for '28 and future years, and we would want to give that to you relatively early in 2027, so, and then at that time we can provide you with updates on all the projects and where they've gone from

there as well.

Q. That would be helpful. Thank you.

THE CHAIR: Okay. I don't think there are any further questions from the Board, so we'll take our one-hour lunch break now. Thank you.

THE CLERK: Order. This hearing will stand adjourned for one hour.

(PROCEEDINGS ADJOURNED AT 12:56 P.M.)

PROCEEDINGS ADJOURNED TO 1:56 P.M.

Volume 3
October 23, 2025
P.M. Session

(PROCEEDINGS RECOMMENCED AT 1:58)

THE CLERK: Order. This hearing is reconvened. Please be seated.

THE CHAIR: Mr. Herbert.

MR. HERBERT: Yes.

THE CHAIR: Can I ask how you're planning to structure your redirect in terms of the full panel here and then your expert witness.

MR. HERBERT: My redirect will be very brief and I just have a few questions on redirect from and after that point we will able to excuse the panel with the exception of Mr. Epp, and he'll be joined by the two representatives from -- who were the authors of the net salvage study.

THE CHAIR: Okay. Thank you. And if you're ready to start now with redirect.

MR. HERBERT RE-EXAMINES THE PANEL:

Q. MR. HERBERT: Thank you, Madam Chair. Ms. Cunha, you spoke about the schedule including Yukon Energy's engagement with the senior officials' working group. Can you clarify for the Board which entities

are included senior officials' working group?

A. **MS. CUNHA: Yes, absolutely. So recognizing that, you know, this is a must have project and that it's important that we meet the schedule, we have had early engagement with First Nation -- pardon me, with the Ta'an Kwach'an Council and Kwanlin Dün First Nation. We have a senior officials group with those two nations that is specific to energy projects and their traditional territory, so we have engaged them in those conversations. And it's actually through those conversations that each of those nations had put forward a parcels of settlement lands to be considered as part of the project.**

In addition to that, we have met with the City of Whitehorse, Yukon government and YESAA independently, one on one, to better understand each of their independent processes and to discuss opportunities where we could do processes in parallel, so for example, public engagement, each of the processes has a public engagement component, so we've been having discussions about how we could streamline that and do those in parallel.

Also from a public fatigue perspective wanting to bring clarity to residents of Whitehorse and the Yukon of, you know, exactly what engagement we're having.

Moving forward, we'll be moving with the City of Whitehorse and Yukon government on a senior officials group or a working group. To be clear, YESAA staff is not part of that group.

Q. Thank you, Ms. Cunha. So just to clarify, that moving forward, the senior officials' working group, Yukon Energy, the two First Nations, City of Whitehorse and the Yukon government?

A. MS. CUNHA: Right now we have two senior officials groups, one with the nations and one with the nonnations government. We will be extending invitations to make one, but currently they are two independent.

Q. Thank you. And can you just elaborate any more on how you expect these discussions to assist in advancing the schedule for the Whitehorse Power Centres project?

A. MS. CUNHA: Yes, absolutely. So what we've -- right now what we know is that by working together with the First Nations early on in the project and we've been having conversations with them for a -- more than a year already is that we're able to identify interest, concerns, partnership opportunities with the nations earlier on in the project and to make sure that they're a part of the project planning and execution early on, which helps expedite the permitting processes, as they

come to fruition.

Q. Thank you. Now, you also made reference during your evidence this morning to Yukon Energy's experience with the executive committee level screening process with YESAB for the Callison project.

Can you elaborate a bit more about how that experience informs Yukon Energy's expectations for the timeline for the executive committee screening process for Whitehorse Power Centres?

A. MS. CUNHA: Yes, right now looking back on our experience with Callison, certainly having that been -- the development of a thermal site, there is certainly a lot of learnings that we had and that we can replicate here with the Whitehorse Power Centre, given that they are very similar projects.

In that regard, the Callison executive screening process took about 13 and a half months and Yukon government was able to issue their decision document within the two-month timeframe, so for a total of about 15 months.

Q. And can you just confirm again when Yukon Energy is expecting to be in a position to submit a YESAB proposal for Whitehorse Power Centres?

A. MS. CUNHA: Yes, we're aiming to do that in March of 2026.

MR. HERBERT: Thank you, Ms. Cunha. Those are all my questions on redirect.

THE CHAIR: Thank you. So the panel members, other than Mr. Epp, can be released now. Thank you.

MR. HERBERT: Thank you. And joining Mr. Epp on the net salvage study panel will be remotely Patrick Bowman of Bowman Economic Consulting and Hayitbay Mahmudov of InterGroup Consultants, the authors of the net salvage study and I understand that they will be attending remotely, but will still need to be sworn or affirmed.

THE CHAIR: And do they need to be registered as well, Ms. Bentivegna.

MS. BENTIVEGNA: No, well, they will need -- if Mr. Herbert wants to give more of an introduction.

THE CHAIR: Okay, thank you.

MS. BENTIVEGNA: But it doesn't have to.

THE CHAIR: Okay. Thank you.

MR. HERBERT: We have filed their CVs with the Board, so I think that should suffice.

P. BOWMAN, H. MAHMUDOV (For Yukon Energy Corporation via videoconference), affirmed.

MR. HERBERT: So I have no questions and so they're open to questioning by Ms. Bentivegna.

THE CHAIR: Thank you. Ms. Bentivegna.

MS. BENTIVEGNA QUESTIONS THE PANEL:

MS. BENTIVEGNA: Thank you, Madam Chair.

Q. MS. BENTIVEGNA: Now, this first question relates to something that you said, Mr. Epp, yesterday, but it does relate to net salvage as well. So when we were discussing, it was a $46,000 in remaining of a capital cost.

I don't know if you remember that, and you've said, you confirmed, that that $46,000 will go to shareholder costs because it was not predicted, and that's if you need to look it up, it's at transcript volume 2, PDF page 78.

Now, this was also in reference to YEC-YUB-65D at PDF page 355, and it was -- that loss of $46,000.

Now, I'm trying to understand what you meant, if you can clarify, when you said that since it was not predicted that loss of $46,000 -- or the remaining cost, capital cost, of $46,000, it was -- goes to shareholders, and it's that part of the sentence -- your sentence that talks about predicting it and we're trying to understand what you meant by that?

A. MR. EPP: Sure. So, Madam Chair, the $46,000-loss has happened. It does not appear in revenue requirement anywhere in the application. Like,

you won't see a claim for $46,000 in '25, '26 or '27, so that's what is meant by that issue.

When I said it's not predicted, I could foresee an example in the future, if we have a replacement planned that is due to now a known condition of an asset that we think we're going to replace it early. So it still has net asset value on it.

We could, I guess, say in the -- we could have -- if we did plan for it in this GRA, I could have said, oh, we're going to replace this item in 2025 because we know it was in bad condition and we've got a plan to fix it and it's got a net asset value of $46,000.

And because it was unexpected overall, but we now -- we know about at the time of preparing the application, we could have then included that $46,000 as a request for a revenue requirement.

Q. All right. So was it the asset retirement or the loss that, or both, that wasn't predicted? I'm just trying to hone in on the reasoning?

A. MR. EPP: In this specific example, the relay test set was determined to not be working properly, so the asset was taken out of operation. That was not expected. It resulted in an unexpected loss, that the -- because of the asset unexpectedly being taken out of service.

Q. Thank you.

Now, can you help us understand how this type of retirement and cost of removal would pertain under or would apply under your proposed net salvage method?

Would it be considered terminal or an interim?

A. MR. EPP: As this is just a tool, I would say it's not included in -- it's not related to the net salvage study. That could be confirmed or corrected by Mr. Bowman.

A. MR. BOWMAN: Madam Chair, my understanding of the example that's being referenced is an asset that is being retired, and that one is dealing with how to account for the book value as it appears on the company's accounts.

That's different than what we talk about when we move to the net salvage study and the net salvage approach, which is where we're talking about a new set of costs that is incurred in order to remove or rehabilitate a site when you remove an asset.

So anything you will see in the net salvage is not talking about how to deal with the original capital cost, depreciation of that capital cost or gains and losses upon retirement of that original cost to install that capital cost.

Q. Rather than focusing in on the example, I'd like to

expand it more to, if there's a retirement under the proposed of an asset -- under the proposed net salvage method, would it be considered a terminal or an interim one?

A. MR. BOWMAN: Madam Chair, as I noted, I'm not familiar with this example and perhaps Mr. Epp will want to add, but in what I had understood you were talking about a tool or a piece of equipment, and it -- because it wouldn't have a net salvage component or a cost to remove it, I'm not sure it would be necessary to classify it, but in general, if it's something that's being removed from a site, but that equipment or that service is still required, so that something new is being constructed at that site or being installed at that site to replace the function of the old asset, then it would be considered an interim retirement.

Q. Then is the converse true where if nothing replaces it, then would you consider it a terminal one?

A. MR. BOWMAN: Yeah, there are only -- Madam Chair, there are only two types of retirements in the way that this language is normally used, interim retirements where the requirement for the service goes on and an asset is simply replaced, and terminal retirements where the requirement for that service no longer exists or is being replaced by some other

functionality in a different location in which case the asset is retired and removed and not replaced in the same general location.

But as I noted, that classification only comes into account when one is dealing with costs incurred to remove an asset, and I don't know that in this example or in the example of any other type of tool that you would actually have costs incurred to remove or to -- an asset or rehabilitate a site.

A. MR. EPP: Madam Chair, I can confirm that there was no cost to remove this.

Q. And under the proposed net salvage method, would this type of asset retirement be considered routine or nonroutine?

So rather than focusing in on just the example of an asset just being removed and not replaced, but looking at it sort of generally, would this type of asset retirement be considered routine or nonroutine?

So I guess if you can explain what routine asset retirement is and what a nonroutine is to us, please?

A. MR. BOWMAN: Yes, Madam Chair, once one has addressed the question of whether an asset is being replaced or its function is being replaced, in which case it's interim, then and if it's not, then it's terminal, then one is left with the question of how do

you deal with the costs for terminal retirements.

Recall that the proposal is that interim retirements, when you have to spend money to take away, say, a transformer, install another transformer on the site, the costs to take away the old transformer would be rolled into the capital costs of the new transformer, so you have a place for those costs to reside, where they will become depreciated going toward.

It's terminal retirements where you don't have a place for the costs to reside. If you were removing a transformer and not replacing it because the need for that function had disappeared. Then you're left with this question of, you know, where do I charge this amount and how do ratepayers pay for this amount?

In most cases you -- where one -- a utility is dealing with a terminal type of retirements, there are normal amounts that are incurred in any given year. They're not generally large. They can be looked at over time in a spread sheet. They can be analyzed in relation to the size of the plant installed, and an amount can be built into rates to maintain a salvage reserve to be able to fund those amounts and to charge them to ratepayers on a relatively stabilized basis. That's going to apply to almost everything that Yukon

Energy will have terminal retirements on.

The problem arises when you have large and uncommon type of retirement experiences, and I'm saying -- I'm not even sure that we can identify one at this point, but if somebody says, well, you know, what if you end up having a major transmission line that you need to retire and you're not replacing? What if you have a hydro site that reaches end-of-life and you have to remove that? Are we really putting aside dollars today to take down a major hydro site? And generally the answer would be no, we don't expect those things to occur. We don't build anything into rates for them.

If they did occur, they're obviously a utility cost. They're obviously a part of the cost of service for that hydro plant, but we're not going to start incurring for them today when we don't expect them -- we don't know when they're going to occur. When they're going to be massive numbers when they were to occur, or large numbers, that does not lend itself well to analysis of a depreciation study or to establishing a funded reserve through rates.

And so what most utilities will do and there are some references in our report is they will say if I'm going to have thing like that, something that is very large, that is unexpected, you know, far in advance,

but at some point may arise, we're not going to pretend that the dollars being put aside over time are somehow supposed to fund that balance.

We're going to say that if that occurs, the utility would have some advance notice, it would come back to the Commission, and it would have to work with the Commission to find a reasonable way to build that into rates so that it could deal with those costs.

But like I said, not something that's a normal event, but not something that somebody would think could be funded from a $350,000 a year accrual or any type of ongoing accrual. I hope that answers the question.

Q. I'm still trying to understand what would be considered routine and nonroutine?

A. MR. BOWMAN: Well, as I said, nonroutine would be something that would be like a major end-of-life event. For example, if Yukon Energy determined that it could no longer sustain a thermal site in the City of Whitehorse and it had to fully remove and rehabilitate that site and relocate it somewhere else. That would clearly not be a routine retirement. It would clearly be very large dollars. It clearly would be planned for well into the future. There would be time to set up an orderly way to address that item through rates, and

that would be something you'd think about as nonroutine.

Q. Thank you. Now, so if an asset retirement were to be predicted or routine, so can you tell us how, Mr. Epp, how YEC views an asset retirement that can be predicted, and if you could give us an example of the subsequent journal entry for a predicted retirement?

A. MR. EPP: Madam Chair, to date we haven't done any predicted retirements.

Q. Thank you. And can you confirm that your statement aligns with YEC's group depreciation practices, which are associated with the development of your depreciation study and depreciation rates?

A. MR. EPP: Sorry, can you clarify the question.

Q. Sure. Well, you just said you can't give us an example of a predicted retirement, and we've been talking about the loss that was -- that asset that wasn't replaced, and wasn't -- was unpredicted.

So I'm just in considering your net salvage study, all that, is it your view that YEC's group depreciation practices, which are associated with the development of your depreciation studies and depreciation rates, that what you've told us confirms to that?

A. MR. EPP: Madam Chair, the disposal of the

protection relay tests, that had nothing to do with the net salvage value study, and once that asset is taken out of service, it is no longer depreciated, and that's within our policies, yes.

Q. Thank you. Now, going to the application, Exhibit 1-A, Appendix 5.3, FX-001 the criteria for capitalization at PDF page 431 to 438, so you'll see there at PDF page 434, acquisition costs for capitalization include but are not limited to and there's a whole list there.

Now, looking -- if you look at the heading "Acquisition Costs For Capitalization" include and are -- as I just -- but looking at item S in that excerpt, the sentence states: (as read)

> "The initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located, the obligation for which an entity incurs either when the item is acquired or as a consequence of having used the item during that particular period for purposes other than to produce inventories during that period."

And then there's an IAS 16, paragraph 16C. Are these to be treated as acquisition costs included in any

capitalized asset that reference that I've just read to you in paragraph S?

A. **MR. EPP: Madam Chair, and Mr. Bowman can correct me if I need any correcting here, but this clause here is specifically relating to an asset retirement obligation in -- under accounting terms, and if I try and relate that to the net salvage value that we were also talking about, I think that's where, what you call a nonroutine transaction, and Yukon Energy does not have any of those nonroutine transactions listed on your books because the accounting rules are it has to be measurable, and as Mr. Bowman said, it's very rare that you know of something and then can -- you know when a diesel plant is going to be taken down in the City of Whitehorse and not replaced.**

But I think if that were to occur, we would have to -- would have had to set up the costs at the beginning, but we -- since we don't foresee that, we aren't able to predict the costs. We have no assets in our books today reflecting that.

Q. Now, going to Exhibit 4, which is the consolidated information responses, and if you can look at 65, YUB-65M at PDF page 357, lines 22 to 28, and then as well the information response at 65(O), which is on PDF page 358. So if you see that.

Now, in looking at lines 25 to 28 of the IR response, which is discussing depreciation expense calculations as shown in the tables, I want to understand more about what YEC's referring to in the headers "Regulatory Accounting and Proposed Rate Setting."

Can you explain the use of this different terminology and what pertains to regulatory accounting and what pertains to rate setting?

A. **MR. EPP: Madam Chair, first, I will note that this is not a net salvage issue. Nothing to do at all with net salvage value. But do you still want me to talk about this?**

Q. Yes, please, because it does relate to depreciation so.

A. **MR. EPP: It relates to, yes, depreciation, completely separate from net salvage value. This is where the YUB directed us in the last rate application to take a look at how we do net depreciation of our property and equipment. Nothing to do with net salvage values.**

So we did research, and in this application we have proposed to change our depreciation method for property, plant and equipment to be consistent with other utilities.

For example, this is -- the way we proposed is the

way ATCO Electric Yukon does their depreciation methodology. It is consistent with Northwest Territories Power Corporation, and we are not aware of any utility actually that does depreciation for rate-setting purposes the way we did in the previous applications, and the reason the utility board -- my understanding why the utility board asks us to do this is because in previous general rate applications, the utilities board had lots of difficulty understanding our depreciation calculations because we did it based on our best estimate on an asset by asset basis, whereas that's not how it's typically done for regulatory purposes.

So the approach in this general rate application for depreciation of property, plant and equipment is to -- we've taken the approach that was -- that we said we would propose in the compliance filing of the last general rate application, which basically takes the opening balance of your asset class, multiplies it by the depreciation rate for that particular asset class, and if there's any additions during the year, you would take half of that calculation for the addition portion.

So again, nothing to do with net salvage, but it is a depreciation methodology response.

Q. Thank you for that explanation, but in your view, is

there a difference between regulatory accounting and proposed rate setting?

A. MR. EPP: Yes. So what we're doing here we have a general rate application. Decisions and methodologies used here are how rates will be set. That will be what makes up revenue requirement. At the end of the -- then we're done with that. Whoops, sorry.

When we finish a year, we actually -- calculate our actual results, and that's based on the normal financial accounting rules, and we then can compare that to -- well, I guess that's just it at that point.

The -- we have -- we will have variances between actual and the approved amounts in everything, and that would -- is what makes up our regulatory or financial income. That's set -- that happens after the fact, after year-end is done. Nothing do with the rate-setting process that we're going through today.

Q. Thank you. Now, going back to that Exhibit 4, but looking at 65(O), the answer to O, PDF page 358, line 19 refers to an industry standard level for the reserve for site restoration, which I take to be referring to YEC's future removal and site restoration, FRSR. Is that correct?

A. MR. EPP: Yes, it is correct.

Q. Thank you. Now, Mr. Bowman, can you point to any depreciation literature or documentation of any sort that refers to the existence of an industry standard level of precollective net salvage costs?

A. MR. BOWMAN: Madam Chair, yes. If you would just clarify whether you're looking for industry standard in terms of practice or are you looking for a literature reference?

Q. It would be useful if you gave us both.

A. MR. BOWMAN: Well, in terms of --

Q. The standard and the literature.

A. MR. BOWMAN: Yeah, in terms of a literature reference, I can provide those, but what you will normally find, if you look in something like the Depreciation Manual produced by the National Association of Regulatory Utility Commissioners, NARUC, they have a volume on depreciation, and what it will basically explain is that what you are trying to depreciate is the service value provided by an asset, and the service value is the initial investment less the value at end-of-life, which would include any positive salvage, as in being able to sell a used truck, for example, if you used the truck for five or ten years, you could sell it for something, your depreciation doesn't need to collect the entire value

of the truck, it only needs to collect the original price less what you're going to sell it for at the end.

And that terminal value, that end value may be negative if you have to incur costs to remove it. For example, if you have a transmission line, and when you take it down, you have to send people out who will take down the poles and pick up all that wire. And that's it. That's a negative cost.

So you would build that cost into the depreciation. So the -- that manual will talk about the idea of a service value for an asset. And so in that sense, yes, there is quite a bit of textbook literature about -- about how one deals with, from a rate setting perspective, removal costs and net salvage.

In practice, when you turn to utilities, the question becomes what is considered a net salvage cost, and that's where most of our report focused, which is looking at the different types of costs that can be incurred when an asset reaches end-of-life and how one accounts for them and which of them are effectively a cost of this asset and which are accounted for in a different way. That's not uncommon.

You always have to look at that set of dollars that will be spent and think about how they will be

accounted for, and but our report is recommending that for Yukon Energy, it use an approach that has been adopted by utilities like Manitoba Hydro and Newfoundland Hydro and AltaLink Management in Alberta, where the interim retirement costs, those costs to get assets out of the way so you can build a new asset in its place, become part of the new asset, and we provide it in our report, references to those utilities and their practice. I can provide the decision numbers if it helps you or references to where the Commission has noted that or where the utilities have explained this in their regulatory filings.

And so because those costs are being added to the costs of the replacement asset, they do not need to be recovered during the life of the assets that's installed.

The only removal costs that need to be recovered during the life of the asset that's installed, which become part of that service value concept then is the terminal retirement values, which is what we explained can be addressed by the FRSR.

FRSR being the name for the account which will address the topic of net salvage. The two are synonymous.

So I can -- like I said, there's both the sort of

literature and the regulatory practice for what we're talking about here.

Q. But is there an industry standard level of precollection of net salvage costs? So I'm looking to see if there's an industry-wide standard level that you have found or is there one or it's just practices and then as you mentioned the literature?

A. MR. BOWMAN: No, well, the -- Madam Chair, there's no single dollar value or no single percentage value that applies because each utility's assets are going to be different, and each utility's removal situation will be different.

Some utilities are operate in urban environment, some operate in rural environment, some operate with much more -- much more generation assets or site specific assets. Some operate with wide-ranging transmission, for example.

So having developed this concept out of the literature and been applied in practice, part of the work that will go into each future depreciation study will be to determine the Yukon Energy specific target, and that will be no different than the work that the -- that a depreciation expert normally does.

They will look at a group of assets for each utility, they will determine the utility specific

estimated life for each type of asset, and they have methods, you know, when we do studies for utilities, methods for looking at how one estimates what the removal costs would be.

Usually that is primarily by reference through utility's own data and own experience, removing assets under a similar accounting regime. And over time you can develop percentages or estimates for what costs should be included, but there's no single standard that's applied. There's no, you know, national approved value. It's part of the work that each utility needs to do as part of their ongoing depreciation studies.

Q. Mr. Bowman, it seems to be what you're just -- and correct me if I'm wrong, but it seems to be at odds with that response, what you're telling me, the response and that's at the O, under the information responses, and I'll read it to you so it says: (as read)

"Yukon Energy's revenue requirement has provided for the collection of annual net salvage expense in the amount of 0.350 million per year on the basis that the balance of the reserve for site restoration is currently at an

insufficient level, and therefore, should be increased to an industry standard level, as summarized in section 3.4.5 on PDF page 100 of the application as detailed in tab 9 of the net salvage study and shown in tab 3, Table 3.13."

So that's what I'm trying to understand is those statements now in relation to what I've just asked you and what you responded.

A. MR. BOWMAN: Right. So, Madam Chair, I will say, you know, I didn't draft this response, but I believe I understand what the words are trying to get at.

The current Yukon Energy situation is entirely not in keeping with an industry standard. Yukon Energy has a balance in an FRSR that was accrued prior to 2005. At that point it stopped adding anything to that account and is just spending it down. And at some point it will hit zero and then it has no -- no ongoing plans to deal with these costs and no practice as to how to deal with them.

So we're outside -- no matter how we approach it, we're outside an energy standard and we need to move towards something that is sustainable and deals with

the fact that these are valid and necessary utility costs and they need to be built into rates.

The industry standard way one would deal with that is to establish your accounting standards and your accounting approaches for the costs which is what our study tries to do, instead of just taking the costs and putting them into new assets. These will accrue over the life of the asset and then to establish a method where you say for those costs where you do need to accrue over time, how high should that be? And how high should that be in and relate -- [audio disconnection] all rolled in and done as part of a depreciation study. You --

THE CHAIR: So I'm afraid, Mr. Bowman, if you can hear, you're freezing on us. We may need to take a minute and we'll have to ask you to repeat your answers.

A. MR. MAHMUDOV: Madam Chair, in the mean time, maybe I can just add a bit of information here with reference to that insufficient level. So we -- in our report we stated that the YEB directed that Yukon Energy discontinue annual accruals to the future restoration account, and then come back to the Board once that balance -- once that liability balance reaches $2 million, and at the moment it's below that

$2 million, and I think that's why the whole study was initiated. But the balance is below that threshold, which was written by the Yukon Energy Board.

Q. And in your understanding, I'm still trying to reconcile the statement in the information response and the information we're hearing now, so is there an industry standard level that's referred to in the tab 9, the net salvage study?

A. MR. EPP: Madam Chair, as Mr. Bowman was saying, and he did not prepare this response, when we were talking about industry standard levels, it's just really the industry standard to have a reserve sufficient in the future, and Mr. Bowman has said how it's industry standard for utilities to do this, and the level is dependent on utility-specific information.

Q. Thank you for that clarification. Now, Mr. Bowman, I don't know if you were speaking when you -- when the screen froze, but did you want to add anything or were you saying something that we should have heard?

A. MR. BOWMAN: Madam Chair, I believe that the last comment I was making was that Yukon Energy is in a slightly unique position here moving from the past situation where there was no accrual to a situation where an accrual is being started again.

We have come up with an estimate as a way to move

forward on that, but it will need to become part of an ongoing part of their depreciation studies. We don't have a depreciation study before the Board at this time, so this is a way to start moving in the direction where this accrual will occur, and then it would become part of the ongoing depreciation studies and over time as this approach is applied, it would gain increased input data from applying this practice, and it would be able to be dialled in, I guess, is the best way to describe it.

Q. Thank you. Now, Mr. Epp, can you confirm that Exhibit 4, response 68, Attachment 1, the PDF page is 429 to 448, it's a revised copy of the net salvage study was submitted; is that correct?

A. MR. BOWMAN: Madam Chair, it's Mr. Bowman here, I -- this is the study that we had prepared, and yes, a revised version was filed. There were two headings which were mislabeled, and so we replaced those and the black lined version is in the response to part A of that information request.

Q. All right. Thank you. Now, still in Exhibit 4, the IR response noted at PDF page 431, in 20 years from 2005 to 2025, the balance of the future removal and site restoration, FRSR, has recorded some 4 million in net salvage costs, which is roughly the difference between

5.7 million and 2 million, for asset retirements that YEC has characterized as primarily routine terminal assets retirement; is that correct?

A. MR. BOWMAN: Madam Chair, it's Mr. Bowman, and yes, in the table I believe two pages on from this sets out the annual spending, adding up to 3.7 million.

Q. And would this mean that all reported net salvage costs have been approximately 200,000 per year? So 4 million divided by 20 years. Can you confirm that?

A. MR. BOWMAN: Madam Chair, it's Mr. Bowman, yes, it's pretty close to 200,000 per year. I get concerned when we're talking about over many years and inflation affecting them, but in a simple calculation, yes, very close to 200,000.

Q. Okay. So can you confirm that this roughly 200,000 per year in net salvage costs were being recorded against the previously collected FRSR as opposed to being a depreciation expense?

A. MR. BOWMAN: Madam Chair, it's Mr. Bowman. That is my understanding, I believe Mr. Epp may want to confirm.

A. MR. EPP: Confirmed.

Q. Thank you. Now, can you confirm that YEC's proposal in this GRA as related to the proposed net salvage study method is to commence accruing 350,000 per year of net

salvage costs to be added to the existing FRSR; is that correct?

A. MR. EPP: Madam Chair, that is correct.

Q. Thank you. Now, to record all net salvage for routine terminal assets retirement against the FRSR; is that correct?

A. MR. EPP: Yes.

Q. Okay. And then thirdly, record all net salvage for nonroutine terminal assets retirements against the FRSR to the extent there has been sufficient precollected funds?

A. MR. EPP: Sorry, can you repeat that, please?

Q. Sure. That you would record all net salvage for nonroutine terminal asset retirements against the FRSR to the extent that there's been insufficient precollected funds -- sorry, sufficient, not insufficient.

A. MR. EPP: Mr. Bowman can correct me if I'm wrong. This account is for routine, is my understanding, as opposed to I think you were referring to nonroutine.

A. MR. BOWMAN: Madam Chair, it's Mr. Bowman. I think we're mixing two concepts here, so I want to be quite careful. Yukon Energy has an FRSR where it is

currently approved and expected to charge removal costs, any removal costs, routine, nonroutine, interim, terminal, whatever. That is what that account is for.

We are proposing to narrow that account so that interim retirements would become part of capital. Terminal requirements would still become part of -- remain in the FRSR.

In terms of charges, things that are charged to the account, that is the end of the story. Now, in terms of how the account is built up over time, we are proposing and talking about Yukon Energy building into rates of $350,000 a year which is based on the estimates we have available, a reasonable amount at this time to get started building up that account, based off of the estimates of routine terminal retirements that have occurred. So based on past practice of 350,000 tied to the 2024 asset base is a reasonable starting point.

The issue you've raised is what if you get a nonroutine one, and of course as we've noted, there aren't any nonroutine ones, but the account is designed and structured to be the place where that would be charged, even if there was a nonroutine one. The issue is we're just not proposing to start accruing for those nonroutine ones today because no one is expecting them.

No one has got an estimate for how much they would cost. No one has an example of one that might occur and there's none in the historical data.

So I think that's the gap. In terms of where it would be charged if we had a nonroutine, it would be charged to this account. But $2 million wouldn't go very far if somebody all of a sudden says you need to do some large nonroutine retirement. Something more needs to be built into rates. So it's the accrual side where right now is being built up just to address keeping up with the routine type of retirements. That accrual has not been built big enough to be able to handle the nonroutine. But if they occurred, they would still flow through the FRSR the balance of 2 million could disappear quite quickly, it could go into a negative position and then Yukon Energy is coming back to the Board to figure out how best to deal with that.

And I guess that's no different than today. If there was a large nonroutine retirement today, it would be charged to that account and the 2 million would become negative.

Q. And so if I understand you correctly, then to the extent that there's insufficient precollected FRSR funds or there's a future material net salvage for

nonroutine terminal retirements, YEC will propose at that time an additional way to fund the larger terminal retirements; is that correct?

A. MR. BOWMAN: Yes, that's exactly correct. If there was, if I understood you correctly, if there was a large charge that occurred or was expected to occur, YEC would have to come back and say 350,000 a year is not going to do it. We're going to have to start building more into rates to deal with this necessary utility expense.

Hopefully it's done with enough time in advance to be able to deal with it in an orderly way, but you know, this is no guarantees that will occur. It certainly, you know, not -- this is not unusual. We were in a proceeding with ATCO pipelines who was looking at needing to retire at some point a large underground storage facility and the Commission said don't -- that's a nonroutine. It's a very large item. It will be some point in the future. We don't know when. We don't know how much it will cost. Don't start accruing for that today. When we get closer and you can estimate a date, you can estimate a dollar value, we'll start building into rates to sort of build up an amount that can handle that.

Q. Thank you. Now, just want to verify or confirm that

YEC, is the proposal that YEC will capitalize all net salvage routine and nonroutine interim asset retirements?

A. MR. BOWMAN: Madam Chair, Mr. Bowman here, that's my understanding. All interim -- all salvage removal-type costs associated with interim retirements would become part of the capital costs of the new asset being built in that location.

Q. And so whether it was a routine or nonroutine interim asset?

A. MR. BOWMAN: That's correct. The interim does not really have a distinction between routine, nonroutine, in so far as that occurs.

Q. Thank you. Now, this proposed net salvage method being modelled to some degree on similar capitalized methods currently being used by AltaLink Management Inc. -- sorry, Limited in Alberta; is that correct?

A. MR. BOWMAN: Madam Chair, I guess AltaLink is one of the utilities that uses a reasonably similar approach, although theirs is still being phased in.

Q. Thank you. Now, either YEC, Mr. Epp or Mr. Bowman, do you agree that one of the major differences between the asset retirements experienced by each utility is that the vast majority of AltaLink's asset retirements have been and continue to be routine interim retirements

whose net salvage costs are under AltaLink's net salvage method intended to be capitalized to the cost of the new replacement asset?

A. MR. BOWMAN: Madam Chair, it's Mr. Bowman. No, I won't necessarily agree with that, and if that -- Mr. Mahmudov may have a better memory than me with the figures, but we are in the middle of an AltaLink proceeding right now and it was a couple of years ago that AltaLink stopped charging interim retirements to their net salvage account. They still have a net salvage account where they only charge terminal retirements anymore, and it is a not immaterial amount of charges that flow through that account every year and forecast to flow through that account.

I -- we may even have cited that ratio in our report, but I'll leave it to see if Mr. Mahmudov's memory of dollar values is better than mine.

A. MR. MAHMUDOV: Sorry, Madam Chair, I'm just trying to quickly check on the fly here, but I don't remember the dollars, but what -- the approach as Mr. Bowman said, I believe that's the correct one.

Q. Now, Mr. Bowman, would you agree that another difference between YEC and AltaLink is that terminal asset retirements for AltaLink are exceptionally rare, whereas terminal asset retirements are more common type

of asset retirement for YEC?

A. MR. BOWMAN: Madam Chair, no, I don't know that I necessarily agree. The -- you know, AltaLink is a transmission facility owner and Yukon Energy of course owns transmission assets.

I don't see any reason why those would be materially different type of assets in so far as terminal retirements. AltaLink does have, as I noted, a notable amount of terminal retirements occurring every year. I have not dug into the transactions but I've seen the dollar values flowing through their accounts and they're not small, and I don't see any particular reason why there would be more or a different scale of terminal retirements in a Yukon Energy who has similar transmission, but also has generation, which doesn't -- generation is not in the habit of closing down a generating plant very often either.

Q. Now, Mr. Epp, do you agree that in the evidence as postulated by Mr. Bowman, that routine interim retirements have likely been getting expensed or -- sorry, it's for -- that net salvage costs, to be clear, routine interim retirements have been -- have likely been getting expensed or capitalized?

I just want to ascertain whether these net salvage

costs for routine interim retirements have been getting expensed or capitalized?

A. MR. EPP: Madam Chair, could we have an example of what you're referring to.

Q. We'll come back to that as we look it up, so we'll go on to other questions in the interests of time.

A. MR. MAHMUDOV: Madam Chair, I just wanted to let you know that I have confirmed here that, with respect to AltaLink's practice, their precollection of salvage start beginning in 2024, and AltaLink has commenced capitalization of salvage beginning in 2024, and that refers to the interim retirement related costs removal.

Q. Thank you. Now, would it be correct to say that YEC's net salvage proposal looks very similar to the traditional method of net salvage in that it seeks to precollect costs that will be incurred in the future?

A. MR. BOWMAN: Madam Chair, it's Mr. Bowman. Yes, that's exactly what we would describe it as. The only difference -- in that regard, it's sort of the same as ATCO Electric Yukon or others who use a traditional approach.

The only difference is that is that the proposal of Yukon Energy is that the scope of costs being collected through that type of net salvage provision are only the terminal, not the interim.

A. MR. EPP: And, Mr. Bowman, just to add on to that, I think in your study -- so this approach is proposing an annual depreciation cost of $350,000, whereas if we were going to include the rest of the terminations, it was something like 4 million a year that we would be proposing.

A. MR. BOWMAN: Yes, the ongoing annual amount based on net salvage percentages that are sort of heavily dependent on looking at other utilities for their practice and their experience in how much net salvage expense they recognize, would be approximately 2 -- over $2 million a year for the annual amount, but it would also, as part of that calculation say, well, how much should be built up for the assets that are already in the ground and have been there for a while, and the answer to that is instead of 2 million in your net salvage account, you should be closer to about $40 million in your net salvage account and if you had wanted to have that 40 million addressed over the remaining life of the assets, you would have to build in another amount that's over $2 million a year.

So the total impact of doing a traditional approach would be something like 4 million a year, if you were trying to start where you are and use the course assumptions of how much might flow through a net

salvage account.

A. MR. MAHMUDOV: And Madam Chair, so just to add further clarification, it's actually $4.7 million is what we have in the -- from the annual accruals for net salvage and the traditional approach which includes all of the interim and terminal retirements.

Q. Now, going on, can you -- any of the witnesses, can you explain the difference in the outcomes that result from determining a percentage of net salvage costs to be precollected, based on the traditional method where the net salvage ratio is based on historical cost of removal divided by the historical cost of the asset being removed and YEC's proposed method to determine a net salvage ratio based on historical cost of removal divided by the current in-service gross property plant and equipment?

A. MR. BOWMAN: Yes, Madam Chair. It's Mr. Bowman. The approach that was taken for this study was to come up with a way to begin to build back into rates an amount that will address the balance in this account and let it start having a normal annual accrual. It was -- it was a way to work with available data and an easy development of ratios that people could understand to get started on an accrual that is not as refined as the product, it will ultimately come

the next time Yukon Energy does a depreciation study.

By the time the next depreciation study comes, the annual accrual will be developed using the more traditional ratios as you talked about where one looks at the historical cost of removal in relation to the historical value of assets retired.

Hopefully we have a few years of data under the -- that can be consistent with this accounting approach, and start to develop some ratios that can be applied, and that would be the way that the net salvage, the FRSR annual accrual will occur in future the next time Yukon Energy does a full depreciation study.

Today's objective was to try to get a framework in place, focus on clarifying how interim retirements will be addressed, focus on getting the start of an annual accrual to the account, and then, you know, having solved that, have a clear framework in place under which the next depreciation study can be performed.

Q. Thank you. Now, Mr. Bowman, do you agree that the traditional method of net salvage relies on the use of a trend of historical net salvage ratios as an predictor of what will happen in the future in terms of expected net salvage costs?

A. MR. BOWMAN: Madam Chair, yes, that's one of the methods, in any depreciation study of the

depreciation expert is challenged by the need to look at multiple perspectives, backward looking is one of those perspectives, but as they say past performance is not always indicative of what will occur in the future.

So the ratios you're looking about in the past performance are something that are included in any given depreciation study. They are informative to how one sets net salvage rates, but they're not always determinative. They are mixed with other perspectives that are forward looking. They're mixed with some other analyses people will do using different assumptions about inflation, and in that regard try to come up with a set of estimates that's durable and forward looking rather than just backward looking, but I absolutely agree that the typical practice and the thing that will occur the next time Yukon Energy does a depreciation study, I'm sure is that backward looking type of analysis that says how much removal costs did we incur in relation to the dollar value of the assets removed.

Q. Thank you. Now, referring to YEC's proposed method, how does a ratio of average historical removal costs to average gross plant and service provide a similar predictive value in terms of expected net salvage, and I'm referring to the historical ratios? And how does

then what's being proposed, does it provide a similar predicted value?

A. **MR. BOWMAN: Madam Chair, the logic behind the ratio is effectively no different than the logic behind the ratio that is -- has been described that would be used were we in a full depreciation study.**

The idea is that the dollars that a utility needs to incur to remove assets is in some way relative to the size of its asset base, to turn over in those assets, those type of factors. A bigger utility would need more dollars.

So this approach was just a way to use readily available data. It didn't require all the work that goes into preparing the input data that one would normally do for a depreciation study. That wasn't available to us. And it wasn't the primary focus of the work, and it probably wasn't the most cost effective way to approach the work when we're going from zero to starting to build something into rates that we know is directionally appropriate and that's going to be refined the next time Yukon Energy does a depreciation study, in any event.

Q. Now, for purposes of estimating net salvage percents or ratios, can you identify any utility precedent for a net salvage ratio being estimated on the basis of the

historical costs of removal divided by the in-service gross property plant and equipment as is being proposed for YEC today?

A. **MR. BOWMAN: Madam Chair, no. There is no -- we are not aware of anybody who would use this ratio, but I'm not aware of any utility who is in the same situation as Yukon Energy, where they're going from zero and an account that is declining and needing to start to build something into rates. So without going through the full work of depreciation study.**

This is a way to get started, come up with a number that is -- that we know is directionally appropriate. It's got a positive amount being built into rates and an accrual, and then let it be refined with all the work that will go into a full depreciation study in the next proceeding I presume.

Q. Thank you. Now, Mr. Epp, you asked -- when I asked you the question about whether you agree that in the evidence as postulated by Mr. Bowman that net salvage costs for routine interim retirements have likely been getting expensed or capitalized, and you asked me for an example.

Now, if I can point you to the application, that's Exhibit 1-A at PDF page 528. So you'll see there regarding -- on that page from the above data it

appears likely that Yukon Energy has -- sorry:
(as read)
"Has approached use of FRSR with restraint, likely accounting for costs as either capital or O&M, which could have been included in the FRSR based on utility industry practice."
So that's -- I was referring to that and asking if what your view was, whether you agreed that that's what's been happening.

A. MR. EPP: Madam Chair, yes, I can confirm that I agree that that is a reasonable statement.

Q. Thank you. Now, next if we can look at the response to YUB 68, Attachment 1, which is the net salvage study, and Exhibit 4 at PDF page 443, and at that page I'm looking at the excerpt that starts with: (as read)
"The final consideration is the overlap with the IFRS asset retirement obligation, ARO. It is understood that Yukon Energy has had little need to record AROs in recent years, so there has been no need to resolve any potential conflict between the activities meant to be reflected in the FRSR and the AROs. Going forward,

there is a potential for more significant AROs. To maintain a complementary operation of FRSR and AROs, it will be necessary to be clear on regulatory versus IFRS accounting. The FRSR is inherent to a financial ..."

And then it goes on.

Now, I'd like to understand, Mr. Bowman, the statement that YEC has had little need to record AROs in recent years.

Can you give me more background on that statement?

A. MR. BOWMAN: Madam Chair, I can, and I believe it's likely Mr. Epp who will want to add at the end of this, but to explain the concept, AROs and the FRSR are each representing a type of liability for the company, but they're very different types of liabilities related in some ways to the same end result.

So one has to be careful that you're not ending up with double counting in the way that you treat them. The FRSR is noted there as a financial liability. It means I've collected a certain number of dollars from ratepayers. I have not yet spent those dollars, therefore I have a liability for the unspent amount. It is a mathematical calculation, add what I've

collected minus what I've spent, that's what I still effectively have a liability for.

An ARO is something different. An ARO is a necessary component of FRSR accounting. The utility cannot avoid it. And it means that the utility has to do an assessment as to whether it has certain future obligations to remove assets that meet a test set out in IAS 16.

At this point in time, and Mr. Epp can clarify, but at this point in time I -- my understanding is Yukon Energy has had zero situations where it has an asset or a future obligation that meets that test. I believe there is one that may be some material that's referenced in an IR, but is -- there are none that have reached that level, so if you go to look on Yukon Energy's balance sheet, you will not see any AROs recorded.

But the ARO is not a financial liability in the same sense of adding up what you've collected minus what you've spent. It is a look at a cost to do something in the future that you have to do and then present value it back to figure out the current present value of doing that thing in the future is and record that as a liability.

It's an action-based liability. The dollars

represent the fact that you must take this action in the future, and they can change it every year for all sorts of different estimates or discount rates.

And so the two of them are trying to get at the same thing, which is what do I need to do in the future, but they're -- and while they're effectively representing the same future event, they're representing it in different ways, and that's the need to avoid double counting, but I think Mr. Epp might want to confirm that what I've just said about Yukon Energy's actual situation on AROs is accurate.

A. MR. EPP: Madam Chair, I do confirm that we have had zero in the past and we have zero recorded in our current financial statements and that has been approved and audited by the office of the auditor general of Canada.

Q. Now, looking at YUB IR Response 66, and those -- that response goes from page 414 to 419, but I'll direct your attention to B, PDF page 414, where YEC was asked to provide detail with respect to how YEC will determine if the costs of removal of an asset retirement -- for an asset -- excuse me, for an asset retirement, whether terminal or interim, are routine versus nonroutine and to include a list of decision points and criterion relied on to make this

determination, and the answer is on page, that I'm looking at, is on PDF page 417 where YEC states in part that: (as read)

> "Nonroutine terminal retirements would be highly infrequent events, such as the decision to abandon or remove a major transmission or hydro asset. No such retirement has been recorded in the accounts of the 2005 to 2023 period, and none is presently anticipated. Such an event would likely drive a need for material ARO liability reporting, and planning and estimating of removal costs would occur well in advance of the removal activity."

So again to go back on that, can you tell us if there's a nonroutine terminal retirement recorded by YEC prior to 2005?

A. MR. EPP: Madam Chair, no, there has not been.

Q. Thank you. Now, if you look at the net salvage study at PDF page 431, it's noted that prior to 2005 YEC used the traditional approach to net salvage as follows, and you'll see there the notation: (as read)

"Prior to 2005, Yukon Energy used an approach to accruing future costs and recoveries associated with asset end-of-life commonly known as the traditional approach to net salvage ..."

And it goes on.

Now, is it possible that the historical data that was collected under the traditional approach to net salvage may contain information that shows a nonroutine terminal -- nonroutine terminal asset retirement prior to 2005?

A. MR. EPP: Madam Chair, while anything is possible, Yukon Energy has been growing over the years. We've been expanding generation assets, transmission lines, distribution lines, so I'm not aware of us ever doing that.

A. MR. BOWMAN: Madam Chair, it's Mr. Bowman here. I suspect it's possible. For example, maybe there's a line that went to the Faro mine that was removed on a terminal basis, but whatever it was, it wouldn't have been nonroutine in the way we're currently using the term, from the perspective that the accruals, annual accruals were able to deal with it.

You know, there was a positive balance of $5.7

million at the end of 2004, even though the accruals were 3, 4, 500,000 a year over that period. So it would not have been one of these ideas that we're going to start to accrue, but if something really big comes along, it's going to dwarf this amount. It clearly didn't dwarf the account.

A. MR. EPP: Madam Chair, just to clarify that, the Faro mine is still being serviced.

A. MR. BOWMAN: Okay.

Q. Now, Mr. Epp, if you know and if not, if you could provide an undertaking, when the YEC offices burnt down, the headquarters, in around 1995, do you know how retirement and -- would that have been recorded, net salvage costs I'm talking about for retired assets, have been recorded terminal or interim, routine or nonroutine, do you have records I guess that would tell you that or do you know?

A. MR. EPP: What I do know is when the plant -- or not the plant, the office building burnt down in '97, so the assets were -- whatever the asset value was at that time, they were written down to zero, and we received an insurance proceeds, and we received I think an insurance gain was recorded of about -- I can't remember, about $10 million anyways, and that still exists on your books, and ratepayers are still

receiving benefit for that amortization of that insurance gain today.

Q. Thank you.

A. MR. MAHMUDOV: Madam Chair, I think it may be worth just pointing out that the net salvage study and proposed recommendations are about the cost of removal associated with retirements. It's not about the retirements themselves.

So if an asset is retired, it wouldn't impact just the retirement cost or what was on the books, it would impact the FRSR account.

Q. Now, still referring to the response in Exhibit 4 at 66B, PDF page 417 at line 13 and 14, YEC states that: (as read)

"If there ever were to be an anticipated terminal retirement such as an event that would likely result in a material ARO liability reporting and planning and estimating of removal costs would occur well in advance of the removal activity?

Is that correct?

A. MR. EPP: Correct.

Q. Thank you. Now, if that were the case, why does YEC feel it's necessary to start the accrual of remediation costs now if the asset retirement obligation mechanism

is going to occur at a very early stage and likely to be the first trigger to recording and estimating the costs of a nonroutine asset retirement event?

A. **MR. BOWMAN: Madam Chair, it's Mr. Bowman. There isn't a proposal to start accruing for the costs of nonroutine events. That is the exception to the accrual occurring today. The idea is to set up in rates accruals that focus on the routine things, and with a note, if you like, a caveat, an asterisk saying if there's something really big and unusual, it's not covered by $350,000 a year.**

It will have to have its own treatment and Yukon Energy will come back to you to propose treatment that -- once it has some information on that, the same as it would if it had an ARO, but it's not given that it would have an ARO, but in the event that it did, it's some of the same information that it would need.

Q. Thank you. Now, we'd like to get YEC -- I'd like to get Mr. -- Mr. Bowman's take on the differences and similarities and interdependencies between IAS 16E respecting property, plant and equipment, to the asset retirement obligation or AROs under IAS 37 and the relationship or bearing of either of those accounting standards to YEC's proposed net salvage method, which is intended to be used for regulatory or rate-making --

and rate-making purposes?

A. MR. BOWMAN: Yes, thank you, Madam Chair. I will start the response by noting -- I am not an accountant. I am familiar with IAS 16 but I am not the ultimate authority on how to interpret those provisions.

The -- but the -- the fact that these two accounts can relate to somewhat the same event and needing to avoid the idea of double counting, what most utilities will do, in my experience, and definitely, for example, we're dealing with Nova Scotia Power right now that does this, on the regulatory side they report only the FRSR for the purposes of the board and for calculating rate base in setting rates.

The FRSR will have an annual accrual associated with it. It will have a balance associated with it, and that accrual and that balance is sufficient to be able to calculate the revenue requirement of the utility.

When the utility then goes away from this Board and has to deal with its auditors, its auditors will have to see that Yukon Energy has done its homework to report whether it has any AROs or not, but if it did do its homework and concluded it had an ARO, and let's, for the sake of argument, let's say it's a half a

million dollar ARO it needs to record, what would be practical is to say if it had a $2 million FRSR balance, it would come to this Board and say I have a $2 million FRSR balance. In dealing with the auditor though, it would record half a million as its ARO balance and one and a half million as its additional liability, regulatory liability associated with the FRSR.

So the balance sheet would look different but it would sum to the same values, and that way this Board can always deal with a single framework, the FRSR-type framework, which it has good information on through depreciation studies and through being able to track the account balance and the reconciliation, and it can use to set rates, and it needn't -- needn't build into revenue requirement an additional amount to deal with anything on AROs. That will just be a way that that FRSR pie is carved up for the purposes of financial reporting.

Q. Now, in response to YUB 66F at PDF page 418, now you'll see Yukon Energy -- it starts with: (as read)

"Yukon Energy performs an annual ARO calculation that is reviewed by the office of the auditor general of Canada. All assets are assessed in an

ARO assessment but only assets that -- that met the definition of an ARO is the energy -- sorry, the only asset that met that definition is the energy storage system land lease. And the ARO of approximately 20,000 was calculated as follows."

And then it explains how it was calculated. Now, in looking at that, how YEC calculated its most recent ARO and provided its materiality threshold, would the response indicate that the ARO was determined to be $20,000?

A. **MR. EPP: Madam Chair, that is correct.**

Q. And now trying to understand the inputs that went into YEC's ARO calculation, these next questions address that.

So as provided in the IR response, can you explain to us whether the $100,000 of estimated reclamation costs in its current 2025 -- sorry, in current -- is in current 2025 dollars or has the $100,000 been determined by taking the estimated reclamation costs in current 2025 dollars and inflating it at some rate over some period of time with the result being $100,000?

A. **MR. EPP: Madam Chair, I believe that is in today's dollars.**

Q. Okay. Thank you. Now, then if it is current dollars, 2025 dollars, the 100,000. Now in trying to follow through on YEC's ARO calculation, can you confirm that the estimated reclamation costs in the current 2025 dollars was inflated by some inflation rate over the period of some years?

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

Q. Sorry, was that Mr. Epp, can or can't?

A. MR. EPP: I cannot confirm that.

Q. Thank you.

A. MR. EPP: I can confirm that this calculation was audited in detail by the auditor -- office of the auditor general of Canada, though.

Q. Mr. Epp, can you undertake to provide the inputs to this calculation that resulted in the 100,000 ARO?

A. MR. EPP: Madam Chair, I believe these are all the inputs into the calculation.

Q. Thank you. Still trying to understand, so was there an inflation rate that was used? And is there discount rate to take the inflated value to the present value? That's what we're trying to understand.

A. MR. EPP: Madam Chair, I believe the calculation is you take $100,000 in the 50 years at the end of the life of the so called end-of-life of this

asset and discount it back by 3.28 percent.

Q. And what would that inflation rate have been?

A. MR. EPP: 3.28 percent is the discount rate, not the inflation rate.

Q. And so did you start with an inflation rate to then arrive at the discounted rate or not? I guess explain to me how that's done?

A. MR. EPP: The -- it's simply the costs are estimated at $100,000, 50 years in the future, you discount that by 3.28 percent to get the present value of $20,000.

Q. So then there wasn't -- the starting point was not the interest rate that then just -- I just want to understand or be clear, that to arrive at the $20,000, you just did the discounted rate, that it's not current costs times inflation rate?

A. MR. EPP: Can you --

A. MR. MAHMUDOV: Madam Chair, I can jump in here to provide my thoughts. So the discount rate of 3.28 from what I understand I believe it is time value of money, so it's basically your investment return; right?

So if you go with 20,000 today and have the investment of 3.28 percent per year for 50 years you will get that 100,000. That does not include the inflation impact. So it is in today's dollars. It's

your -- assuming that 3.28 is -- does not have any inflation built into it. It is your -- a real return of money, so it's time value of money before inflation.

Q. Now, can you tell us the historical costs of the asset to which the estimated reclamation costs are related to, given the assets are still in service and could also call -- that you could also call them current plant and service costs; correct?

A. MR. EPP: Sorry, Madam Chair, what costs are you referring to?

Q. The 20,000, the discounted 20,000 or the 100,000 that you started off with.

A. MR. EPP: So the 100,000 is the cost -- this is specifically at the battery site, which we have a land lease for, so really there hasn't been -- there's not much done there. We have some concrete pads poured there, and to get them to remove them in the future, that's the process. That's what we are getting it back to the original site as.

Q. So then Mr. Epp, what are the costs of that asset that we're talking about, that land lease or land -- you just said it, but?

A. MR. EPP: The last lease is one thing. The cost of the concrete that we poured is a different asset.

Q. So then for net salvage, you're separating out then the cost of your lease or the land, and what you've done sort of with the concrete, so the net -- so are you then saying that it's the cost of both those assets, the land, and concrete, just to use that example, or is it just -- are we just talking the land and lease and concrete? I'm just trying to understand --

A. MR. EPP: Sure.

Q. -- what it refers to?

A. MR. EPP: So the land lease is an asset just for accounting purposes. It's a capitalized land lease. There's no cost to end a land lease. The reclamation costs are to remove the concrete from that land in the future.

Q. And that's what that 20,000 represents? I mean, once it's discounted and all that?

A. MR. EPP: Yeah, the $20,000 represents the cost, the present value of the cost to remove that concrete in the future.

Q. Thank you.

A. MR. EPP: The cost of the concrete is part of the battery project. You'd find the concrete costs in the battery project itself, the installation of the concrete.

Q. So, Mr. Epp, would you have the historical costs of the

land and the lease of this battery asset?

A. MR. EPP: Yes, I believe the -- well, sorry, can you say that again, the lease -- say that again?

Q. And the land?

A. MR. EPP: The land, there is no cost to the land. It is property we are leasing.

Q. Okay. And the lease?

A. MR. EPP: The lease I believe this is -- we paid $1 million for this lease in advance.

Q. And so then that -- the concrete we've been talking about and its removal then would be a nominal cost, am I correct?

A. MR. EPP: The concrete is not part of a lease. It is part of the battery project.

Q. Right. But that's -- the discussion we've been having is what would it cost to remove that battery, so you said concrete, so is there other things that are encompassed in that calculation with regards to where you have an ARO of 20,000?

A. MR. EPP: No, there is not -- and just for -- to hopefully put a perspective on this.

The only reason there is an asset retirement obligation potential here in the future is because this land is leased. If Yukon Energy owned this land, it would not meet the definition of an asset retirement

obligation.

The auditor felt that because there is a possibility we may not have the land in the future, that it met the definition. In all reality, this land will be renewed and renewed and renewed.

Q. Thank you.

A. MR. BOWMAN: Madam Chair, it's Mr. Bowman, and I think this is a good example of what I was referencing about how AROs and terminal salvage are attempting to represent the same thing, but they use different considerations.

In a net salvage account over time, as you are able to develop the data and figure out the ratios, you would be aiming to have $100,000 or $100,000 in 2025 dollars available to you at whatever point you need to take out that concrete, whether you owned the land or you leased the land, but it only shows up as an ARO if you lease it and not if you own it, because ARO has a different type of test, but it's a cost to Yukon Energy in the future when the batteries are no longer on the system, if they reach the terminal retirement point and the concrete is no longer good and it has to be removed and it's a terminal retirement, that's the cost of having had those batteries in service and that's what we're starting to accrue for with the 350,000

today.

Q. Now, looking at and we did before, that the report in Exhibit 1-A at PDF page 528, and now looking at 1- -- the responses in Exhibit 4, 67A at PDF page 423, so if you look at that, please.

Now, in these two IR responses that I've just mentioned, Mr. Bowman asserts that YEC may have been either capitalizing or expecting interim retirement net salvage, and I went through that with you, Mr. Epp, when we went back to that question.

Now, has -- based on this statement, on a comparison with YEC's peer utilities, do you agree, Mr. Bowman, or do you have anything to add, so that YEC has been either capitalizing or expensing interim retirement net salvage costs historically and has based this -- and so has based this statement on comparison with YEC's peer utilities, and I want to know, Mr. Bowman, if you agree or have anything to add to that statement?

A. MR. BOWMAN: Yes, Madam Chair, I would add that -- the question that I believe is referenced on the next page, you'll see the transactions that occurred for the years that were requested at the top of the next page of this IR response, and there's very few transactions.

In many years there is one or two transactions. In some years there is zero. That's -- for utilities that are keeping a close eye on what are removal costs, they won't have one or two or three in a year. They will have, you know, many, many of these transactions, many of them being quite small, but almost every capital job will have some degree of removal or net salvage cost.

I believe ATCO Yukon has even asked to have a ratio applied so they don't even have to track it because effectively almost every job should have some of these costs, but it's not uncommon for a utility of Yukon Energy's size to not have the systems in place on a routine basis to be able to do that type of estimating over time.

And so the fact that we are trying to put in place a system where you don't have to identify the interim costs anymore, you don't have to look at every time you replaced a pole how much of the company's time was spent taking out the old one versus adding the new one. It all just becomes capital costs for replacing the pole.

It simplifies and makes it easier going forward for the company to manage the tracking because it no longer needs to track those interim retirement costs,

it just becomes part of capital. Which as I said is basically what it's been doing by default because it hasn't had that type of tracking in place, as is evident by the very small number of entries in this account.

So that's the first comment I would make. This is not only a mathematical way of helping manage rates. It's also a way of helping put in place a system that's more practical for the utility of this size and this resources.

Second is the fact that Yukon Energy was not using this account to the extent that it may be or would have or could have if it had a very refined system to find all of these and record all of these. It wasn't -- this doesn't harm ratepayers in any way. I think it probably benefited ratepayers because some of these costs were probably expensed just as operating costs when they could have validly been charged to this regulatory deferral, and Yukon Energy took those into its net income over time and is now behind us, as that doesn't harm ratepayers.

If anything that's aided ratepayers over the years, and so I think the concern is the implication that they may not have been doing a thorough job implies that there's something, you know, something

missing that may be a disadvantage to the ratepayers. That's not correct. If anything, like I said, it's a benefit to the ratepayers.

So I think those two perspectives I think are important to recognize in regard to this statement.

Q. Thank you. Now, following up on Mr. Bowman's statements, Mr. Epp, can you explain if YEC gives instructions to its employees or consultants with respect to where to record let's say a timesheet, labour hours, spent in active removing an asset from utility service?

A. MR. EPP: Madam Chair, Yukon Energy employees are given directions to record the time to where the work is spent. The actual work order that is created by the operations department may be very broad and may not be broken down into -- you don't spit out time to -- it's basically for the whole work. It's not actually broken down into different components of the job they are doing on that specific project.

Q. So then would you say that -- I just heard you say, you know, sometimes it's a broad -- the work order is broad and it's not broken down, so then would that mean that employees or consultants have the discretion as to where to record where the labour hours spent in the act of removing an asset from utility service?

A. MR. EPP: No, so what I mean is there may be a work order for them to go out and fix a transmission line. They will -- there's one work order for that. They will spend time travelling out there. They will have fuel going out there. They will have materials out there. They will record their time for all of that for removing the old asset, adding the new asset, returning home, and that is one work order. That's what I meant.

Q. Right. And where would that work order be recorded? Is it like an expense? Does it go to capital? Is it out of this FSR account for removing the asset, like, part of it -- FRSR. So that's what I'm trying to understand?

A. MR. EPP: Yeah, depending on the project, it could go to be expensed or capitalized or we could have -- as we see here, we've done some to the FRSR account.

A. MR. BOWMAN: Madam Chair, I just note that there are some to the FRSR account. They would be far more rare than one would expect given the degree of assets and activity that occurred in Yukon Energy, which was the point that we were making.

Q. Now, Mr. Epp, given that could be viewed as a lack of control because these work orders, as you've explained,

cover all the work, how would capitalizing interim retirement net salvage costs have affected the integrity of YEC's business cases and related capital forecasts?

A. MR. EPP: Madam Chair, this is not a lack of control.

Q. Can you elaborate a bit more?

A. MR. EPP: In what way?

Q. Well, what you mean by -- you've just explained that the work is done as a whole as opposed to broken down, so that different components, so for example, the salvage --

A. MR. EPP: The --

Q. -- can be recorded?

A. MR. EPP: For example, the operations staff works on many different jobs, and they can have many different work orders throughout a day. If they work on, say, 10 different jobs during a day.

If we have to break each job down by well, this was the travel time here, this was the time I did this part of the job, this was the time that part of the job, I'm not sure it provides any value and it would definitely come at a cost because then operations employees is putting more time on their timesheet than actually doing work.

Q. Maybe if you can look at it another way, is there -- in your view, would there be little effect on ratepayers from capitalizing interim retirements net salvage costs as opposed to going to the FRSR account?

A. MR. EPP: Can you repeat that question, please?

Q. Sure. So Mr. Bowman was talking about how there may be, and I think you've mentioned as well, benefits to not breaking down these costs and what the impact might be from capitalizing the interim retirement net salvage costs or the effect on ratepayers from expensing them, so I'm -- on O&M, so what I'm trying to understand is what is your understanding about the impact of the method that you've been using on ratepayers?

A. MR. EPP: As Mr. Bowman said, it's been beneficial to ratepayers.

A. MR. BOWMAN: If I can just help with the components of that. It's Mr. Bowman, Madam Chair. If you take the idea that somebody is doing a capital job and they -- let's say it's a million dollar job but 100,000 of it is -- could have arguably been removal costs and 900,000 could have been capitalized. If they record it in the more detailed fashion that takes all the extra effort on timesheets and tracking and the like that Mr. Epp noted, the FRSR would go down by

$100,000 and the plant and service would go up by $900,000, and because FRSR is an offset to rate base, rate base would change by a million dollars.

If they don't do the tracking, the capital asset will go up by a million dollars and the FRSR won't change, so rate base will go up by a million dollars. So to the extent that it's put into capital as opposed to being put against the FRSR makes no difference to rate base. It makes a very small difference to depreciation in any given year, but the idea of doing a routine update to depreciation expense and depreciation studies is that even that would net out after a small amount of time, particularly for Yukon Energy that was not accruing to the FRSR, it meant that the FRSR balance we had in place lasted a lot longer than was anticipated.

I was on Yukon Energy's panel at the 2005 GRA, and dealt with this topic, and at the time when the Board elected to stop accruing to it, I know that we were thinking that it might last 10 years, the balance, and here we are 20 years later and the reason it's been able to not have an accrual in part is because less has been tracked to it.

The net effect then of those that end up as capital as opposed to being charged the FRSR is

therefore very small. But it's possible and without, I don't know, possibly an omelet that could never be unscrambled at this point, it's possible that some of those tasks were actually tracked as capital. It's possible some of them were tracked as operating costs.

You'll hear examples of utilities that do removal costs or salvage activities. You know, sometimes years after the asset was removed. Sometimes you have to clean up a site. Sometimes you have to go back and pick up remaining parts and the like. And if they didn't know that they could or if the team didn't make a work order to be able to charge that against the FRSR, that would have ended up in just in operating costs and expense and that wouldn't have been in anybody's revenue requirement or rate base it just would have been something that went against the company's net income and that year as an O&M expense.

So that's where I'm saying that if anything ratepayers probably benefitted from the fact that this was not necessarily every possible nickel wasn't being charged against the FRSR. But overall the parts that went to capital versus the parts that FRSR would make very little different to revenue requirement and it's a part of the reason we recommend not trying to implement a system going forward that is impractical for a

utility of this size that offers very little benefit.

Q. Thank you.

MS. BENTIVEGNA: Thank you, panel. Those are my questions, Madam Chair.

THE CHAIR: Thank you, I believe there's at least one question from the Board.

MR. WORONIUK QUESTIONS THE PANEL:

Q. MR. WORONIUK: Hi there. Thanks for being here today. These questions can be answered by either Mr. Epp or Mr. Bowman. One second, sorry.

Regarding the Callison project, would the diesel engines and any supporting assets that are going to removed from downtown Dawson as part of that project be considered a nonroutine terminal asset retirement?

A. MR. EPP: Thank you for the question, Mr. Woroniuk. First of all, the Callison part of things is a separate, it's yeah, the one project there, and we do not have any estimated costs to decommission that site as we plan on using that in perpetuity.

Regarding the assets that are in downtown Dawson, we -- my understanding, and we don't have the rest of the panel here to confirm this, so we'll see how this goes, but right now we are keeping all the diesel engines in service and using them as much as we can because we're short of generation as we've said.

When we do take these engines out of service one by one, that doesn't actually -- it's -- we aren't actually getting rid of the site. We're just getting rid of the -- one of the engines, and we don't have an estimate of -- I think we have a -- in our five-year plan I think we have an estimate of a few hundred thousand dollars to do that take away of the engine, but it's not scheduled within the test period.

Q. Okay.

A. MR. EPP: And that is all subject to check.

Q. For sure, yeah.

A. MR. EPP: Not my area of expertise.

Q. Acknowledging that Mr. Murchison has been released, that subject to check, and then sort of a couple quick questions and that can be part of an undertaking because Mr. Murchison isn't here.

It's my understanding that the engines in downtown Dawson will be removed when they reach end-of-life, and I was wondering if that information on those end-of-life dates for those engines can be provided as part of an undertaking?

A. MR. EPP: Sure. We can take an undertaking on that.

UNDERTAKING - TO PROVIDE THE INFORMATION ON THE END-OF-LIFE DATES

RELATED TO THE ENGINES IN DOWNTOWN DAWSON AND WHETHER THEY WILL BE REMOVED WHEN THEY REACH END OF LIFE

Q. MR. WORONIUK: Okay. And related to that, just to confirm at this point you have -- there's no internal Yukon Energy Corp. internal forecast on when all of these diesel engines would be removed from that location?

A. MR. EPP: That's correct. We have no estimate of that to my knowledge.

Q. Thank you. No further questions.

A. MR. BOWMAN: It's -- thank you for the questions. It's Mr. Bowman here. I just would add if you'll see a note, when the Whitehorse diesels were removed, 1, 2 and 3, that cost of removal was run through the account, and it would be similar in the future, and if the Dawson diesels were considered, you know, whether it's terminal routine or not routine, they would run through the account, and they would become part of the analysis in the future as to how much ratepayers need to pay on an ongoing basis.

But if it's anything like the scale of costs in Whitehorse or less, which I would -- I think the Whitehorse municipal probably considerably larger. That scale of costs would not make up -- you know,

would not need a special accrual, a special sort of nonroutine type of accrual at that level.

MR. WORONIUK: Thank you.

THE CHAIR: Okay. Then I'll just check, Mr. Herbert, did you have any direct questioning for the redirect for your witnesses?

MR. HERBERT: No, I don't. Thank you.

THE CHAIR: Okay. I believe all witnesses can be released from this panel then.

It's been a long three days for you, Mr. Epp.

A. MR. EPP: It's been fun.

(PANEL STANDS DOWN)

THE CHAIR: So I just want to speak briefly to the outstanding procedural actions in respect of the application. As I understand them, the deadline to file written undertakings is October 28th, final written argument is due November 12th, and the written reply argument date is now due November 27th.

I just want to check, are there any procedural aspects that -- or information that I'm missing or should be added to that?

MS. BENTIVEGNA: No, Madam Chair.

THE CHAIR: Thank you. I'll be very quick.

I just want to take the opportunity to thank everyone who has taken part in this hearing over the

three days, including all those who have already left. You all bore with me through my first chairing; that's really appreciated.

Mr. Yee, I think I can see you're on the line. I want to thank you for your well-prepared and efficiently presented questioning.

I'd like to thank the entire YEC team, panels and otherwise, for all the work, all the answering they had to do.

I want to really thank the Board's technical, legal and support team and the members.

And I want to shout out by name the court reporters, who I didn't have your names before, Leanne Kowalyk and Sonja Petryshyn, and our technical support, Mike Hamm.

And thank you, this hearing is now closed.

THE CLERK: Order. This hearing is now closed.

(PROCEEDINGS ADJOURNED AT 4:15 P.M.)

PROCEEDINGS CONCLUDED

Certificate of Transcript

We, the undersigned, hereby certify that the foregoing pages 329 to 503 are a complete and accurate transcript of the proceedings taken down by us in shorthand and transcribed from our shorthand notes to the best of our skill and ability.

Dated at the City of Whitehorse, Yukon Territory, on October 23, 2025.

"Leanne Kowalyk"

Leanne Kowalyk, RCR, CSR(A)
Official Court Reporter

"Sonja Petryshyn"

Sonja Petryshyn, CSR (A)
Official Court Reporter

- I N D E X -

VOLUME 3

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