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IN THE MATTER OF THE YUKON ENERGY CORPORATION 2017-2018 GENERAL RATE APPLICATION

Heard before the

YUKON UTILITIES BOARD

June 26 - 28, 2018

WRITTEN ARGUMENT OF JOHN MAISSAN

Final Argument introductory comments

In the preparation of this written final argument the transcript was referenced by page and line numbers and whenever possible. This reference will appear in brackets as Tr for transcript, p for page number, and Lx-y for line numbers. For example, a reference to the transcript at page 428 lines 17 to 19 would appear as (Tr p428 L17-19). The Yukon Utilities Board is referred to as "the Board". Interrogatory responses (IR) will be referenced by their identifying numbers.

In this argument I address both issues in which I am in agreement with the applicant, Yukon Energy Corporation (YEC), and issues on which I have a differing view or disagree with the applicant. My silence on issues and requests of YEC in this argument are not to be interpreted as agreement with, or disagreement with, YEC's request or position. I leave these matters to the Board to address based on all the information on the record.

The topics outlined in my final argument below generally follow the order in which they appear in the application and/or were raised during the hearing as considered appropriate.

Section 2 Sales and Generation

1. System peak load growth

YEC in its application (p2-18) forecast a peak load of 91.8 MW in 2017 and 92.9 MW in 2018. The actual peak load reached in 2017 was about 92.7 MW (late in the year) and the actual peak load reached in early 2018 (February 5) was about 92.99 MW. In cross examination during the hearing (Tr p222 L18 to p224 L6) the above average energy sales were attributed to sustained colder than average temperatures. However, it was acknowledged that the new record peak load occurred on a cold day but not an extreme cold day – it was not -40 degrees (Tr p224 L2-4) (I do not believe that any -40°C temperatures were recorded in Whitehorse in the winter of 2017-2018). Had Whitehorse experienced a day below -40 degrees the peak may well have been greater.

It would appear that there is a trend to higher than anticipated peak loads, at least in part due to the installation of electric heat in new construction (Tr p440 L8-15). Coupled with the economic up-turn in Yukon's economy (Tr p440 L508) and a shortage of housing which is driving home building, peak loads are likely to grow significantly in coming years.

Recommendation: that the Board encourage Yukon Energy to communicate closely with ATCO and other parties to forecast as accurately as possible the high peak load growth rates; and that the Board encourages Yukon Energy to focus on Capacity DSM, as well as capacity and energy based resource options to meet the increasing peak loads and the new mining energy requirements.

2. Sales Forecast

Preliminary actual sales for 2017 at 421.567 GWh (CW-YEC-2-1 REVISED p3 of 7) were about 21.5 GWh higher (excluding secondary sales) than YEC's updated forecast. Increases were primarily due to increases in wholesale sales (14 GWh) and industrial sales (5 GWh), but increases were experienced across the board. The corresponding firm load generation was 446.458 GWh, which according to Table 3.4-1 (Application Appendix 3.4 page 3.4-17) suggests that thermal generation would need to provide about 61% of all marginal increases in generation (up to 450 GWh grid load).

Serving Victoria Gold's Eagle Gold project's electrical energy requirements was also expected to require about 60% (or a bit more) thermal energy. We do not yet know when or if the Alexco mine will go back into production, but clearly having continuous up-to-date mining related load information is very important too.

Recommendation: That Yukon Energy be encouraged to work closely with ATCO Electric Yukon and all active and potential industrial customers in order to generate sales forecasts that are as accurate and up to date as possible.

3. Diesel and LNG thermal generation mix

The percentage of diesel and LNG that make up the thermal generation mix that YEC needs to run has been questioned (JM-YEC-1-12, JM-YEC-1-13 and JM-YEC-2-4 among many others) and discussed at some length (Tr p235 L19 to p238L 16, and others). The actual ratio for 2017 was 73% LNG and 27% diesel (Tr p114 L16-24).

For long term average thermal generation requirements, which does not include generation from monthly thermal unit run-ups for maintenance nor generation for capital & RIFD projects, YEC forecasts a mix of 90% LNG and 10% diesel. The excluded requirements listed may result in a different actual mix in any given time period.

When using a short term forecast the thermal mix assumed by Yukon Energy is 60% LNG and 40% diesel (Part 2 of ERA proceeding Appendix 2.2 Short-Term Hydro Alternate GRA Forecast page A2.2-3). The reason provided is that there is a tendency for diesel to dominate smaller and shorter duration thermal requirements.

When cross-examined, YEC described how control room operators decide whether to run diesel or LNG generation when thermal is needed (Tr p231 L13 to p234 L14). There followed shortly thereafter (Tr p235 L19 to p238 L16) a discussion that culminated in the conclusion that what thermal generation is required drives the decision on whether LNG or diesel is most appropriate. It was evident that the forecast that was used in a regulatory proceeding would not result in different instructions to operators and thus has no bearing on the decisions made on a day-to-day basis.

Mr. Osler summed it up neatly by saying that "… about all it really comes down to is if the short-term water forecast, which is part of the short-term forecast, is showing that we have a lot of water relative to the load, the diesel percentage would be higher." (Tr p237 L3-7). The obvious conclusion is that regardless of whether a long-term or a short-term forecast had been used in a GRA, the actual mix in any particular circumstance will not vary with the forecast used in that GRA. Neither the intervenors nor the Board should be distracted by the fact that the short-term alternative forecast (which was based on an abundant water supply) forecast a different LNG and diesel mix than the long-term average water forecast (which would necessarily be based on the lower long-term average water supply).

If YEC's forecast of 90% LNG in the long-term is too high, YEC bears the risk, not the ratepayer (Tr p281 L5-15).

4. Long-term Vs short-term forecasts

A discussion far more relevant to ratepayers than the LNG and diesel thermal generation mix is on whether long-term average water forecasts or short-term water forecasts should be used to forecast thermal generation requirements and therefor the costs to be included in rates in any test year period.

There were extensive discussions between YEC and the Board's staff in the hearing on short-term and long-term forecasts (Tr p557 L23 to p577 L23). In addition, there were numerous IRs (including JM-YEC-2-5 and JM-YEC-1-21-REVISED) that touch on the subject. The key take-away messages are that there is considerable variability in the inflows of water from year to year (Tr p565 L11-14 and p239 L12-23) and that this will translate directly into considerable annual variability in thermal energy requirements and thus costs. With the use of short-term forecasts for rate setting this in turn will result in considerable variability (instability) in consumer rates (Tr p576 L1-9 and JM-YEC-2-5).

Based on the response to JM-YEC-1-21 REVISED and the discussion on the transcript at pages 242-244, the fluctuation (from maximum charge to maximum rebate) could be as much as 3 cents per kWh with a DCF cap of $8 million as it now stands. At an average residential rate of about 15 cents that is about a 20% variability. If we take even that cap away and go to a short-term forecast only, the volatility would be substantially greater. There is no doubt that consumers would be very upset if they experienced the kind of rate instability that relying on short-term forecasts for rate setting would generate. This level instability should not be allowed to take place.

Recommendation: It is my strong recommendation that the Board order YEC to use long-term average water forecasting for the purpose of determining long-term average thermal generation requirements for the DCF calculations and thereby stabilize rates as much as possible in the long term.

Section 3 Revenue Requirement

5. No-cost power

With the implementation of the Micro-Generation Program in 2014 YEC (and ATCO) started getting power from customers that have installed qualifying energy producing systems, principally solar PV. These systems export power to the distribution system to which they are connected whenever there is a surplus relative to the need of the customer. This export is purchased by the Yukon government from the customers and is available to the utilities at no cost. The total volume of such exports from customers is still modest but is growing at a significant rate. YEC should include estimates of this increasing amount of no-cost power for each year in its next GRA application in Table 2.2 (or equivalent) so that a full picture of energy sources is provided.

Recommendation: That the Board order YEC to provide estimates of no-cost power from the Yukon Government's Micro-Generation Program in its Summary of Energy Balance, Losses, and Peak table in its next GRA application.

6. Deferred costs – Brushing and Reserve for Injuries and Damages

There are deferred costs that have been building up since YEC's last GRA test year of 2013. These include $2.215 million to the end of 2016 (Application p3-20) for Brushing and $1.059 million RFID (Application p3-15). Given that there have typically been 2 or more non-test years between GRAs such costs can add up and result in larger rate increases than would otherwise have been the case.

Recommendation: that the Board not order YEC to defer any more costs than absolutely necessary.

7. Vegetation Management (brushing) Policy

YEC has studied vegetation management issues for some time and has established a plan of regular brushing that has reduced outages and is lowering the cost of brushing (Application page 3-10). It does not include the use of herbicide at this time.

Recommendation: that the Board approves YEC's Vegetation Management Policy

8. Climate change study

As mentioned on page 3-18 and detailed on page 5.4-2 of the Application, YEC proposes to spend $599,000 over 5 years as YEC's share of a cost-shared climate change study. YEC presently maintains a number of water flow and level measurement stations as part of their water licence requirements and / or as necessary for prudent water management in their hydro facilities. In addition, Water Survey of Canada maintains a number of water measurements stations throughout Yukon and Canada. The Yukon government Water Resources Branch measures the water content of the snow pack in March and April annually in many locations including in YEC's hydro catchment basins. Environment Canada also has a number of weather stations scattered throughout Yukon.

There is thus a lot of publicly funded data gathering, data that is available to everyone, including YEC. YEC uses some if this water data in its YECSIM model which is updated with the most recently available hydrological information from time to time. YEC thus has access to data from which it can detect any long-term trends as they develop.

Given that there is this large data base, and that there is an urgent (and costly) need for YEC to develop new electrical capacity and energy supplies for the Yukon grid, it is not justifiable to saddle the ratepayers with another $599,000 to study the effects of climate change. In the present circumstances this kind of rather academic research should be the responsibility of YEC's shareholder, Yukon Development Corporation, or the Yukon Government. YEC needs to spend millions of dollars on the urgently required new energy and capacity supplies at the expense of ratepayers, so spending on this academic research should not be to the ratepayers' account as well.

Recommendation: that the YUB disallows the cost of the proposed climate change study as an expense to ratepayers.

9. Cost of debt

On pages 3-21 and 3-22 of the Application YEC outlines it debt obligations and outlines its interest cost reductions with respect to debts owed to Yukon Development Corporation (YDC). In substance what has happened is that the Yukon government through YDC has subsidized YEC's debts down to significantly lower interest rates. The taxpayers are subsidizing YEC debt in order to keep electricity rates lower. This is false economy. With the pattern of reducing long-term debt interest rates what will happen when long term interest rates go up? Will they be "renegotiated" upwards every few years?

Recommendation: that the Board accepts the cost of debt as proposed by YEC and requires YEC to provide expiry dates (or terms) for each of the debt instruments and provide a guarantee or assurance that the interest rates on the long term debt instruments will not be "renegotiated" upwards before the end of their term.

10. Return on Equity

Return on equity information and calculations are provided on pages 3-22 an 3-23 and in Schedule 8 of the Application. The calculation of ROE appears to be quite straight forward.

Recommendation: that the Board approves a return on equity of 8.82% as proposed by YEC.

11. Diesel Contingency Fund (DCF) cap

YEC discusses the DCF in their Application at pages 3-24 to 3-26. YEC raised the question of the adequacy of the DCF cap but did not provide a proposal to change the cap from its present $8 million either up or down. In JM-YEC-1-21-REVISED the impact of three levels of cap ($8 million, $16 million, and $22 million) are examined for three different annual load levels 420 GWh (13.9 GWh thermal), 450 GWh (28.6 GWh thermal), and 490 GWh (50.9 GWh thermal). The 420 GWh firm load is approximately what was forecast for 2017 and the 490 GWh load was intended to approximate the firm grid load with the Victoria Gold gold mine connected to the grid. The actual grid firm load for 2017 at 446 GWh came close to the 450 GWh load modelled (CW-YEC-2-1-REVISED).

JM-YEC-1-21-REVISED at page 5 of 8 shows that with the DCF cap at $8 million and a grid load of 420 GWh (2017 forecast) annual surcharges as high as $13.63 million per year can be expected under drought conditions, conditions actually experienced in the past 35 years of record. On 385 GWh of sales (420 GWh firm load less 35 GWh losses), this is about 3.5 cents per kWh or over 23% change on 15 cents per kWh (roughly the residential rate). If the cap were to be increased to $16 million, the maximum annual surcharge would be only $4.67 million, roughly one-third of the cost of an $8 million cap. This is far more reasonable in my view. And since the maximum annual surcharge goes up as the firm load increases (and it did increase substantially in 2017) the potential rate instability impact would only increase without an increase in the DCF cap.

With the firm load generation at 420 GWh and adding in the (partially seasonal) Victoria Gold mine, the firm load generation would increase to about 490 GWh. This would result in the maximum annual surcharge of $11.79 million with a cap of $8 million. With a cap of $16 million this is still the same, but with a cap of $22 million the maximum annual surcharge would decrease to $5.27 million.

The matter was also discussed in some detail in the hearing (Tr p238 L22 to p244 L15) during which YEC indicated that they support an increase in the cap.

Recommendation: in view of the fact that firm load is exceeding forecast levels and that there is a PPA in place to start serving Victoria Gold's power needs in March of 2019, I recommend that the Board order that the DCF cap (positive and negative) be increased to $16 million effective immediately.

Recommendation: that the Board order Yukon Energy to bring forward with its next GRA a more thorough analysis of a range of potential DCF caps for discussion and decision at that time.

Recommendation: In the event that YEC does not come before the Board with a GRA for 2021 as a test year, or sooner, and the Victoria Gold mine is still receiving electrical from YEC, that effective on January 1, 2021 the DCF cap be raised to $22 million.

<u>Section 5 Capital Projects</u>

12. Continued planning to meet future generation requirements

YEC outlines the need for continued planning to meet future generation requirements in its Application on page 5-3 an on pages 5-31 through 5-51. Some of the projects are specifically identified (for example the battery project, and the Sumanik wind project). Others are not but use technologies that are supported by the Yukon government's Micro-Generation Program and would presumably be supported through the coming Independent Power Producer Policy (and the Standing Offer Program within it), including solar PV and wind generation. These specific examples have a diurnal (daily) energy supply component – they can by their nature, or are designed to have, a daily variation that is potentially beneficial to the grid. To fully evaluate these diurnal benefits requires a model other than YECSIM which cannot perform this function.

Such a model was discussed in the hearing (Tr p211 L11 to p212 L3) and it would appear that EC is indeed looking for and evaluating such a model. Given YEC's need and focus on new energy and capacity supplies during the test years and beyond, such a model is urgently needed.

Recommendation: that the Board order YEC to proceed expeditiously with the evaluation and selection of a model capable of assessing the benefits of energy and capacity supply projects with a natural or designed diurnal supply component, and that a model must be available for use by YEC no later than the end of 2019.

13. Aishihik elevator shaft

This project is detailed in the Application at pages 5-5 and 5-7 to 5-8 and covered in an IR (JM-YEC-1-24). In the examination of the YEC panel by Mr. Landry a correction to the YEC GRA Application was made – the depreciation period for this asset was reduced to 40 years from 72 years (Tr p18 L16 to p19 L11). In my view the correction to a 40-year depreciation is appropriate.

Recommendation: That the Board accept the cost of the Aishihik structural steel refurbishment and that a 40-year depreciation period is appropriate.

14. Aishihik electrical and control upgrades

The Aishihik electrical and control upgrades project is discussed on pages 5-8-11 of YEC's Application. This project, and the RTU in particular, was discussed in the hearing (Tr p495 L13 to p497 L8). Aishihik is a key hydro plant and is the grid's "-1" vulnerability in the “N-1” planning criteria. I fully support the proposed upgrades including the RTU replacement.

Recommendation: that the Board accepts the Aishihik electrical and control upgrades project as proposed by YEC.

15. Communications upgrades p5-12

At pages 5-12 to 5-14 of the Application YEC outlines a $1.003 million project to upgrade communications systems throughout the Yukon. This project was also discussed in cross examination at pages 467 to 474 of the transcript. In Undertaking 24 YEC outlines some cost savings and provides a list of benefits that the study consultant identified in 2016.

The Yukon grid is getting more complex and in my view the need for improved communications and redundant systems for reliability, particularly under emergency circumstances, is real. I support this project.

Recommendation: that the Board approve the Communications Upgrades project.

16. LNG plant p5-22 p3-17

In 2014 the Board recommended the Minister approve the LNG project. The project construction was already underway and was commissioned in mid-2015. The projected cost savings were not realized as sales decreased rather than increased thus reducing the requirement for thermal generation. As well, the world price of oil decreased substantially reducing the cost of diesel fuel from a forecasted $1.1265 per litre (JM-YEC-1-27 p3 of 7, L22) to $0.8583 per litre on August 1 2017 (JM-YEC-1-27 p4 of 7, L13).

On August 25, 2017 Hurricane Harvey hit Huston Texas. This affected oil refineries in the area and the reduced refinery capacity increased the cost of refined oil products in North America starting in the fall of 2017. With summer demand for fuels costs have remained high and YEC currently pays $1.0278 per litre (YEC response to 2017-2018 GRA hearing Undertaking 12 and 13, page 2 of 13, item 2d).

YEC was asked a number of IRs on the LNG plant including JM-YEC-1-27. During the hearing the information provided in this response was discussed (Tr p263 to p271). YEC agreed to provide additional information as Undertakings 12 and 13 and this was provided to all parties on July 3, 2018. During the hearing YEC confirmed that the dual fuel diesel / gas alternative presented as the “diesel” alternative to the LNG plant, was 13.4 MW in capacity. This is comparable to the LNG plant with 3 generating units (Tr p264 L7-17). YEC also confirmed that the dual fuel “diesel” alternative to the LNG plant included upgrades to serve a third dual fuel generator (Tr p299 L9-22).

In YEC’s response to Undertakings 12 and 13 on pages 6 and 7 of 13, two figures are presented that compare the LNG plant with 3 generators to the alternative 13.4 MW dual fuel plant on a more equal basis. Figure 1B compares the two alternatives with $18.3 million in contributions and Figure 2 compares them with no contributions. YEC concludes that the difference in capital costs between the two options would be repaid in 7.2 years (Undertaking 12 and 13 response p4).

For this payback period to be realized, though depends on various implicit or explicit assumptions, including:

1. The costs for the infrastructure to service a third 6.7 MW dual fuel generator remains in the capital cost of the dual fuel alternative to LNG;
2. That there is no reduction in the cost of diesel fuel projected reflecting the return to service of the refinery capacity impacted by hurricane Harvey;
3. That the new dual fuel diesels would only supply 50% of the LTA thermal requirements vs. 90% for LNG. [Why would YEC choose not to run the more fuel-efficient new diesels in preference to the old ones the same way they run the LNG units?];
4. That the present cost of energy in gas will remain at the present 32% of the cost of energy in oil ((JM-YEC-1-27 p3 of 7, L11-13), when historically it has been in the 70% to 100% range (evidence in ATCO 2016-2017 GRA); and
5. Despite the Victoria Gold mine coming onto the grid in 2019 there will be no new renewable energy supplies added to the grid to offset the added thermal generating requirements within 7 years. Yet YEC has several planned projects that are to be in service within the next few years (2016 Resource Plan update).

These assumptions all favour LNG. With different assumptions the analyses would show that the case for LNG would be marginal at best. Clear objectively comparable analyses have not been provided to the Board or the public on the LNG project and its alternative(s).

Recommendation: that the Board order YEC in bringing forward energy supply projects in future to provide the Board and the public with objectively comparable ("apple to apple") analyses of alternatives that YEC examine and provide analyses on a range of realistically possible outcomes of the implicit and explicit assumptions.

17. LNG third engine

YEC is in the process of installing a third 4.4 MW LNG / gas generator at their facility in Whitehorse. This project is described on pages 5-26 to 5-28 of the Application and is forecast to cost approximately $8.90 million to completion in early 2019 (YUB-YEC-1-71). The cost per MW of capacity is about $2.02 million. This compares to about $3.11 million per MW of capacity for a new 20 MW diesel plant and $5 million per MW of capacity for a new 20 MW LNG plant (YEC 2016 Resource Plan, Appendix 5.15 Thermal Energy Plant Development Study by Stantec page 3.6). The battery storage option was estimated to cost from $5.425 million per MW (4 MW lead-acid) to $3.425 million per MW (8 MW Lithium-ion) of capacity (from information on page 5-36 of the application).

The total installed capacity of the LNG plant will thus be increased to 13.2 MW and firm annual energy capability will be about 110 GWh (JM-YEC-1-28). The plant's total annual energy capability of about 110 GWh is about twice the long term annual average thermal energy requirement of 51.1 GWh for a grid load of 490 GWh including the Victoria Gold mine. It would also be enough to meet the thermal energy requirements in all but 3 of the driest water years on record (JM-YEC-1-21-REVISED page 3 of 8). It is understood that there would still be a diesel peaking requirement in cold weather, but the annual LNG energy capability is substantial.

The cost of capacity for the third LNG generator is well below that of the available alternatives, and together with the existing 8.8 MW of existing capacity, the annual energy capability of the LNG plant will be able to supply most of the grid's energy requirements, even with the Victoria Gold mine on the grid.

Recommendation: that the Board approve the purchase and installation of the third LNG generator.

18. Battery project

The details of YEC's proposed battery project are provided on pages 5-34 to 5-36 of the Application and in response to IRs (e.g. JM-YEC-1-31). The costs of the two battery options identified as possibilities, lead-acid (4 MW 40 MWh) and Lithium ion (8 MW 40 MWh), were estimated at $21.7 million and $27.4 million respectively. This represents $5.425 million per MW and $3.425 million per MW respectively. YEC discussed their application to NRCan for funding support for this project during the hearing (Tr p483 to p485).

In the hearing YEC said that the project is only being brought forward on the basis of its capacity for meeting peak load (Tr p249 L1-5; p251 L10-16; p482 L9-17). However, the Trans Grid Solutions (TGS) Evaluation of Energy Storage Technologies conducted for the 2016 Resource Plan (Appendix 5.19) mentions several other benefits including power quality, grid support, and possible integration of other renewables into the power grid (page iv).

During the hearing YEC acknowledged these other potential operational (non-capacity) benefits (Tr p249 L6-11) and even implies (Tr p249 L16-19) that a battery may have been of some benefit in reducing the extent of the outages that were being discussed.

When asked about the potential fuel saving benefits of a battery YEC said that they had not yet valued operational benefits (Tr p250 L23 to p251 L6). YEC's Application at page 5-35 footnote 30 quotes the TGS report as indicating that based on 2015 data 2443 MWh per year of diesel could be displaced with a 4 MW 40 MWh battery. This is consistent with between 60 and 70 complete charge-discharge cycles of a 40 MWh energy storage battery. The annual operating cost for such a battery is estimated by TGS as being about $210,200 per year (TGS report page 51). YEC estimates that the cost of LNG and diesel generation are $0.1467 and $0.2633 per kWh respectively (Application pages 3-4 and 3-5). Thus, if a battery can offset 2443 MWh of diesel with LNG or offset LNG with hydro, a saving of more than $0.10 per kWh, the annual saving would be about $244,000 – over the estimated annual operating cost.

In summary a battery can provide capacity for the grid at $3.425 million per MW compared to a new diesel plant at about $3.11 million per MW, although there is a bigger spread in the levelized cost of capacity (but battery costs are decreasing over time). Plus, if appropriately designed, a battery can provide benefits like improved power quality, the integration of additional renewable resources, the reduction in the extent of outages or faster restoration from outages (Tr p257 L21 to p258 L1), and cost savings that offset its operating costs. It seems a very worthwhile project and, in my view, should proceed even if the funding support from NRCan does not materialize.

Recommendation: that the Board support YEC's battery project even if the funding support from NRCan does not materialize.

19. New thermal plant project 5-36

In order to provide for the Yukon grid's growing peak load as well as for the retirement of the oldest diesels in the fleet YEC has proposed a new thermal plant of up to 20 MW. The Stantec study (Appendix 5.15 to the 2016 Resource Plan) indicates that a diesel plant would be lower in capital cost than and LNG plant with storage incorporated ($62.2 million or $3.11 million per MW vs. $100.0 million or $5 million per MW). Subsequent to the completion of the resource plan a possibility of an LNG storage depot by an LNG supplier has come to the fore. This would have the possible effect of reducing the capital cost for an LNG/natural gas plant and might make it competitive with a diesel plant for peaking use. However, the cost of LNG fuel would be increased and diesels would retain the advantage of their ability in cold load pick-up (restoration from outages).

In the Application (page 5-38 and 5-39) and during the hearing (Tr p255 L3-16) the possibility of removing the retired Mirrlees engines from the existing diesel plant and replacing them with dual fuel (diesel/gas) engines was discussed. The dual fuel option was the alternative to the new LNG plant at the time of the Part 3 Application proceeding before the Board.

In my view it is appropriate to very seriously consider the option of removing the retired Mirrlees generators and refurbishing the plant with dual fuel engines. This approach would remove any risks related to permitting a new plant site, provide the advantage of using the existing diesel and LNG storage facilities for lower cost gas supply when the the engines are being used primarily for energy, and the advantage of having diesel fuel available for use when the engines are being used for restoration from outages (or any other step-load increase for which gas is not well suited (2016 Resource Plan Appendix 5.15 pages 3.4 and 3.5).

Also, YEC has an existing diesel plant facility in Faro and any diesel generators retired from this plant could also be replaced with new diesel generators. This would also reduce the requirement for a new greenfield plant.

Recommendation: that the Board order YEC to provide a detailed comparison, including pros, cons, capital costs, operating costs, and timeline to in-service for existing diesel plant refurbishment(s) and the two greenfield options (diesel and LNG/gas).

20. DSM

In 2013 ATCO Electric Yukon (then YECL) submitted a joint ATCO and YEC DSM plan. The Board approved some elements of the plan and not others. YEC and ATCO have carried out the approved DSM programs and all of them have successfully provided savings to all stakeholders (application p5-40). All expenditures should now be allowed to be recovered.

The proposed 2013 joint DSM program also proposed to target electric heating in the residential sector as the extensive study identified significant growth in energy consumption due to electric heating in both the residential and commercial sectors. The growth in peak demand on the Yukon grid and DSM were discussed both in IRs and in the hearing (JM-YEC-1-3 & 30, YUB-YEC-1-80, Tr p222 to p224, Tr p461 to p467). The increased load rather than an extreme low temperature was seen as the cause of the high consumption and the peak load (Tr p224 L2-6).

YEC now proposes to develop and implement a capacity-focused DSM program. It is very unfortunate that the Board chose, in 2011, not to approve the proposed electric heat-based DSM program as DSM programs are known to require a long ramp-up period to implement and to have a beneficial effect (Tr p467 L13-21). YEC now has a lot of catch-up to do and all of the new electrically heated homes built almost entirely with baseboard electric heating in the past 5 years will be difficult to influence. There are heating options available (heat pumps and electric-thermal storage (ETS) units) and potential partners out there (Energy Solutions Centre, Yukon Housing, JP Pinard, Yukon Conservation Society) that are anxious and willing to play a significant role in assisting in this effort. The use of ETS has significant potential to shift the electric heating loads to off-peak times and thus to mitigate the high growth rate in peak demand. Some ETS units can also replace individual baseboard electric heaters.

ETS heating units are a mature, off-the-shelf technology that is being promoted by utilities in Canada (Nova Scotia Power and Summerside PEI for example) and in northern environments (Alaska in particular). This technology has been used in Europe (night-store heaters) for many decades.

YEC needs to move forward with some urgency on DSM to address the peak, because any potential not addressed will add to more diesel generation on the peak and the need to buy and install more thermal peaking capacity. The money proposed for the use on a climate change study would be far better utilized on such a program.

Recommendation: that the Board approve the recovery of past DSM expenditures in the manner requested by YEC.

Recommendation: that the Board order YEC to proceed with capacity-focused DSM program design and implementation expeditiously using all available past and present information and experience, and to work with all possible partners to penetrate the market as quickly as possible.

21. Marsh Lake storage (SLESP) and Mayo Lake storage (MLESP)

In its Application on pages 5-46 to 5-49 YEC outlines the continued work on these two projects. Maximizing the output from our existing hydro plants in a manner that is supported by the affected First Nations, is very desirable from the perspective of minimizing requirements for thermal generation and its associated climate changing emissions.

Recommendation: that the board supports proposed ongoing work on these two potential hydro enhancement projects that is completed in a prudent manner that minimizes risk of failure.

22. Time of Use Rate Structure and Smart Grid study

YEC requests approval of $100,000 for a Time of Use Rate Structure and Smart Grid study (Application page 5-50 and P5.4-3). This study was discussed during the hearing (Tr. P479 L14 to p481 L9). Despite the Board's disallowance of ATCO's proposed contribution of $100,000 in their 2013 to 2015 GRA, ATCO is still going to contribute $100,000 (Tr p481 L6-9). I am convinced of the benefits of time of use (TOU) rates and I am familiar with benefits achieved in smart grid approaches in villages in Alaska where very significant amounts of wind energy have displaced diesel generation. There would be significant benefits to ratepayers in the long term if the utilities embrace TOU and Smart Grid approaches in Yukon, both on the hydro grid and in diesel served communities.

Recommendation: That the Board approve the $100,000 budget for the proposed TOU and Smart Grid study.

23. Sumanik wind study p5-50

In their Application on page 5.4-3 (Appendix 5.4 to Application Section 5) YEC outlines its plans and budget for the completion of the Sumanik wind study. During the hearing YEC indicated that they had not yet made the decision as to whether to continue wind resource assessment for another year or to complete the study now (Tr p260 L9-16). Wind power is probably the only renewable form of energy available in Yukon that has a peak output in winter when the electrical loads are highest. As wind is not dispatchable (cannot be turned on or off as needed) it requires supporting generation in the form of dispatchable hydro or a battery or thermal to provide the firm capacity. A battery such as the one being planned by YEC facilitates the integration of wind power into the grid.

In this GRA hearing the increasing winter energy growth and peak load growth has been discussed and recognized by all parties. With the connection of the Victoria Gold mine to the grid coming in March 2019 the annual thermal requirements will increase further. It is thus imperative that YEC continues to explore all possible sources of renewable energy, particularly winter energy. Wind energy which is predominantly available in winter can and should be part of YEC energy supply portfolio.

Recommendation: that the Board approve the continued work on the Sumanik wind study proposed by YEC.

<u>General comment</u>

24. Government influence on YEC decision making

Over the past 10 years we have seen significant amounts of direct government subsidies in various projects (Mayo B, Carmacks – Stewart transmission project Phase 2, Aishihik third turbine, LNG generation plant). There have also been more indirect subsidies through reduced interest rates on long-term debts and contributions to study costs being written-off and amortized.

In the absence of these subsidies two things would be happening, the cost of electricity would have been increasing and Yukon Energy would be under pressure to reduce capital and study expenditures. With increasing rates consumers would have increased incentive to reduce electricity consumption and reduce the demand for more electricity supply. Keeping rates low through unnecessary subsidies increases the demand for power thus creating the need for new projects which in turn will increase the cost of power creating a spiral of increasing costs and subsidies. This is in no one's best interest.

Increasing rates would put pressure on YEC to reduce its expenditures to minimize cost increases. It seems to me there is room for reduction in the expenditure on YEC projects and studies. The proposed climate change study is an example of a non-critical study that could be cancelled. Instead we have seen an increase in direct and indirect subsidies whether to influence YEC project decisions or to make less than optimal YEC decisions seem prudent. This too benefits no one in the long run.

Respectfully submitted,

John Maissan
August 9, 2018