Yukon Conservation Society
(YCS)

TOPIC: Carbon Pricing and Social Cost of Carbon

REFERENCE:

PREAMBLE:

QUESTION:

a) Please describe YEC's understanding of the difference between carbon pricing, carbon tax and the social cost of carbon.

b) Please describe how YEC factored in carbon pricing to the models used in making decisions around thermal generation.

c) How does or will carbon pricing affect electricity rates in Yukon?
   i) Explicitly: with carbon tax rates starting at $10/T, to $50/T as has been indicated by Canada.
   ii) Implicitly: incorporating carbon reduction policies that do not rely on a direct tax, such as clean energy policies or electric vehicle policies. These policies can result in an implied carbon price as high as $210/T.
   iii) In the following scenarios:
      (1) No mines
      (2) Minto mine only
      (3) Minto plus Victoria Gold
      (4) Minto plus Victoria Gold plus Alexco

ANSWER:

(a)

YEC used the terms social cost of carbon, carbon pricing and carbon tax interchangeably in the portfolio analysis of the 2016 Resource Plan. The social cost of carbon values used in the portfolio analysis are different from the carbon tax values proposed by the federal government, since the 2016 Resource Plan analysis had been undertaken prior to the federal government carbon tax announcement. The rationale for using the social cost of carbon and selecting its values is discussed in detail in the Social Cost of Carbon section

(Section 6.2) of the Market Assessment chapter (Chapter 6) and Social Cost of Carbon appendix (Appendix 6.2) of the 2016 Resource Plan.

(b)

The social cost of carbon was translated from $/t of CO^2 eq to $/kWh and added to the cost of every kWh of generated energy in the portfolio analysis of the 2016 Resource Plan. Also, the upstream and downstream greenhouse gas (GHG) emissions costs were added to every asset to include the life cycle analysis of GHG emissions. The details are discussed in the Social Cost of Carbon appendix (Appendix 6.2) of the 2016 Resource Plan.

(c)

Even though the federal government announced the carbon tax starting in 2018, the carbon tax was not considered in the GRA since the implementation mechanism was not known and, consequently, the rate impact would be speculative. As well, determining an accurate rate impact depends on several factors such as load, YEC assets, and inflows. All of these factors are subject to change from one year to another.

The financial impact of a carbon tax will be paid through fuel costs. By definition, any increase in the unit price of fuel is charged to the Rider F account.

(i)

For the potential carbon tax equal to $10/t CO^2 and $50/t CO^2 eq, the rate increase is less than 0.2% and 1% respectively, under the assumptions of thermal generation forecast for 2018 as presented in the 2017-2018 GRA and the conservative assumption that all the thermal generation will be diesel. The simplifying assumption that all the thermal generation would be diesel was made to provide the upper bound for the rate impact. In reality, considering that the thermal generation would be split between natural gas and diesel, the rate impact might be lower.

(ii)

Under the assumption of a hypothetical carbon tax of \$210/t CO^2 eq, the potential rate increase would be less than 3% under the assumptions listed in the answer to YCS-YEC-1-1(c)(i).

(iii)

Based on the assumption of the assessment of the long term annual average split between thermal and renewable generation of 2% and 98% respectively, as per the mixed portfolio for the medium industrial scenario load presented in the 2016 Resource Plan portfolio analysis, and conservative assumption that all the thermal generation would be diesel, the estimate of the rate increase for the carbon tax of \$50/t CO2 eq is approximately 1%.

TOPIC: Demand Elasticity

REFERENCE:

PREAMBLE:

QUESTION:

a) What will be the predicted effect on electricity consumption (demand) when/if the rate increase is granted?

ANSWER:

The predicted effect of a rate increase would be to encourage consumers to reduce electricity consumption in order to reduce costs. No specific elasticity impact has been estimated.

TOPIC: Decentralization and Digitalization

REFERENCE:

PREAMBLE:

QUESTION:

The relationship between utilities and their rate base (customers) is rapidly changing, as customers also become suppliers. As the nature of the grid changes from a hub and spoke model to a network of multiple suppliers and customers, there will be changes to the income and expenses of YEC.

a) Please provide an analysis of YEC's understanding of this shift, and how a transition to an energy management network will be implemented by YEC.

A smart grid will be integral to accommodating the above change. This will involve smart meters and other, more complex changes to manage the rapidly changing flows of electricity from multiple intermittent sources.

b) Please provide a thorough exploration of how this will work, how much this will cost, and how will it be paid.

ANSWER:

(a) and **(b)**

At this time, the YEC grid is not mature enough for implementation of the changes listed in the above questions and, as a consequence, no corresponding studies have been completed by YEC. The resource plan is updated on an ongoing basis. YEC monitors technological changes as they become significant and will address them as required as part of future planning processes. The changes listed in the above questions are on YEC's planning horizon and once the corresponding studies are conducted, the implementation methodology, as well as technical, financial, environmental, social and economic consequences of the changes will be brought forward for consideration as part of future reviews.

TOPIC: **Cost Overruns**

REFERENCE:

PREAMBLE:

QUESTION:

a) What was the average percent cost over run for past capital projects?

ANSWER:

(a)

The question as presented does not inform the prudency of these costs, and also does not provide any limit as to which past capital projects are to be reviewed. The Application includes all information necessary for the YUB to assess capital costs for inclusion in rate base.

TOPIC: **Mayo A and Mayo B**

REFERENCE:

PREAMBLE:

QUESTION:

a) Please describe the capacity and annual yearly energy output of Mayo A prior to construction of Mayo B for the past twenty years.

b) Please describe the capacity and annual yearly energy output of Mayo B since its construction/in-service.

c) Please describe the annual yearly energy output of Mayo A and Mayo B combined since the latter's construction.

d) Was the imminent end of life of Mayo A understood at the time of Mayo B's proposal?

e) What was the net benefit or increase in capacity and energy output of Mayo A and B combined after Mayo B was constructed, considering and including various constraints of water use and availability.

f) What is the cost of the downstream flooding remediation? Please include all costs incurred by ratepayers and work done by Yukon Government.

g) What is the annual cost to service the debt?

h) After including the above costs (flooding mitigation/remediation and servicing the debt), please provide an analysis of the value of the project to ratepayers and taxpayers when the "no-cost money" of federal government grants are included.

i) After all costs (those added to rate base as well as government grants) are considered, what was the cost per MW of net increase of capacity?

ANSWER:

(a) through **(i)**

The analysis sought in these questions is not relevant to this proceeding. The Mayo B project was reviewed by the YUB prior to construction via the Part 3 process and was further assessed for prudency at the 2012/13 GRA. As a result of that process, the YUB has already approved Mayo B costs into rates.

To assist the parties in reviewing specific other issues raised, YEC can provide the following:

- Downstream flooding remediation costs – flooding issues in Mayo are not related to Mayo B development; YEC incurred one-time costs to address the flooding events in 2010 (prior to Mayo B development) but there are no additional costs in this Application related to flooding issues.

- Interest – interest on the Mayo B Note is disclosed in the Application, Tab 7, page 7-15, l.20.

TOPIC: **Aishihik Hydro 3**

REFERENCE:

PREAMBLE: According to information supplied in the GRA, cost to YEC to settle the action was $1.6M, of which $0.96M was legal fees. YEC indicates it is appealing this decision, on advice from legal counsel (which will benefit from continuing the action).

QUESTION:

a) What would the cost have been to YEC to settle instead of continuing the action with associated legal fees?

b) Please explain why it would not be more prudent to cut the losses and accept the decision now rather than incur yet more legal fees.

c) Please provide an estimate of the costs to continue to pursue this action to YEC's legal counsel's advised conclusion.

ANSWER:

(a)

YEC attempted to settle with the contractor through multiple rounds of negotiation, including a court-sponsored mediation process, but unfortunately an agreement was not reached.

(b)

The evaluation of YEC management, with the support of legal counsel, is that there is a net benefit accruing to YEC if they are successful on appeal (i.e., expected award exceeds cost to appeal).

(c)

Estimated costs to pursue the appeal to conclusion are $0.250 million.

TOPIC: **SCADA Communications Upgrade**

REFERENCE:

PREAMBLE: The SCADA project for Dawson, Faro and Carmacks is described as allowing YEC to run many new services and protocols to these sites.

QUESTION:

a) Please provide a list of these services and protocols.

b) How does the addition of these services and protocols advance the 20 year Resource Plan?

c) How will the addition of these services and protocols enable integration of EV charging, storage and dispatching, IPPs and the multiple micro gen projects likely to come on line in the near future?

ANSWER:

(a)

Protocols are as follows:

- Modbus-TCP
- DNP3
- IEC61850

Services (not limited to) are as follows:

- Time
- SNMP
- Backups
- Radius
- Remote access

These are the immediate technologies to roll-out, any other service or protocol that runs on IP can be implemented in the future.

(b)

This project was not specifically undertaken to advance the 20 Year Resource Plan.

(c)

The addition of these services helps bring YEC's communications infrastructure to a modern standard, allowing increased flexibility and opportunities to integrate various new technologies.

TOPIC: **LNG Facility**

REFERENCE:

PREAMBLE: The failure by YEC to fully consider the YESAB process and the requirements of YOGA resulted in cost overruns of approximately $5.45M.

QUESTION:

a) Please describe the lessons learned and actions taken so that future capital projects will not incur similar unanticipated but predictable cost overruns.

b) Please confirm whether the demolition costs and the transportation and FN benefit costs are part of this $5.45M or, as it was indicated that they were removed, should they be added to the $5.45M cost overrun.

c) Given that capital projects managed by YEC almost always incur unanticipated extra costs, how much confidence should we have that installing the third LNG generator will come in on budget?

d) Please summarize the reasoning behind YEC pursuing the LNG facility.

e) Does YEC believe that the LNG plant was a prudent investment?

f) During the extensive work done for the 2016 20 Year Integrated Resource Plan, YEC determined that the Levelized Cost of Capacity (LCOC) for diesel was lower than the LCOC of LNG. This is counter to what YEC argued in the LNG proceeding, when YEC was determined to construct the LNG facility as a capacity project. Please explain what has changed in the few short years that would explain why diesel is the thermal/capacity choice moving forward, as described in the new Resource Plan, when it was not at the time LNG was being actively pursued by the public utility.

g) When decisions around opting for an LNG facility were made, the price gap between the price of natural gas and diesel was at an all time high. Please provide an analysis of the payback of an LNG over diesel plant under current conditions.

h) Please include scenarios where overall demand does not increase and scenarios where increasing amounts of intermittent renewable electricity feeds into the grid.

ANSWER:

(a) through **(h)**

YEC proceeded with the LNG Project as a least cost option to meet increased capacity requirements driven in part by the retirement of two Mirrlees units at Whitehorse, in addition to short term energy needs identified at the time. The project was undertaken subsequent to a period of extensive and unprecedented (for the post 1987 era) expansion of YEC's renewable energy capability,[1] and project planning occurred in the context of grid energy load forecasts that were then accepted for GRA and other planning purposes.

The prudence of the LNG Project was reviewed in depth, and confirmed, by the YUB during the Part 3 proceeding.

Subsequent to the Part 3 proceeding several material changes occurred to affect the project's economics, including:

- Regulatory delays and change requirements that delayed proceeding on the planned schedule and design, and resulted in major increases in capital costs relative to prior forecasts;
- Reductions in grid energy loads (and therefore in long-term average thermal requirements) which acted to reduce the opportunity for fuel cost savings with LNG versus diesel generation;
- Delays in securing lower haul cost options for LNG supply to YEC; and
- YDC capital contribution that in effect removed any capital cost penalty for this initial LNG project relative to the new diesel alternative that would otherwise have been implemented.

[1] i.e., the Mayo B and Aishihik Third Turbine developments, and the connection of the WAF and MD grids subsequent to the Mayo Dawson Transmission extension).

Subsequent to this project's development, the requirements for new capacity have been confirmed and currently constitute a major ongoing challenge for the Yukon grid. Delivered fuel costs for LNG have also been confirmed to provide savings relative to diesel generation, with improvements in this regard over the past 12 months.

The final costs for the LNG Project, and the factors accounting for the cost increase (as well as any other relevant considerations) are fully reviewed in response to YUB-YEC-1-70(a). Table 1 in that response also addresses demolition costs, transportation and FN benefit costs. Updated cost estimates for the 3rd Engine are provided in response to YUB-YEC-1-71.

Please see the response to John Maissan-YEC-1-27 for review of the Part 3 proceeding forecasts and subsequent outcomes relating to capital costs, delivered fuel costs and grid load requirements through the 2017 and 2018 test years - including updates to the table and figure used in the Part 3 proceeding to review the project's overall economic costs and benefits. Based on all changes since the Part 3 proceeding, including the YDC capital contribution, all fuel cost savings from the project now represent a growing net economic benefit for ratepayers.

With regard to the 2016 Resource Plan references in the question, please see the response to YCS-YEC-1-13 regarding why LNG was initially not seen as an economic option for this large scale thermal plant expansion, and why it is now being considered as an option – as well as the option of refurbishing the Whitehorse Diesel Plant with dual fuel engines that facilitate use of the LNG and diesel fuel infrastructure already established at this location. The analysis throughout continues to focus on the same factors as were reviewed in the LNG Project Part 3 proceeding – with the objective to secure the needed new capacity as soon as practical with reliable and least cost resource options based on consideration of capital and fuel costs. Reduced energy load forecasts on the grid can limit opportunities for LNG to provide fuel cost savings of sufficient magnitude to justify a 20 MW LNG facility.

With regard to the question's references to regulatory risks related to the LNG Project, the following are noted:

- Yukon Energy did not fail to fully consider the YESAB process, which YEC had by that time had ample successful prior experience with the Carmacks Stewart Transmission and Mayo B projects.

- o Regulatory risks were clearly identified in the Part 3 Application for the LNG Project and discussed in detail during the interrogatory process and the hearing process for the project.

- o The draft YESAB Screening issued prior to the YUB Part 3 review report did not indicate any material environmental issues that threatened proceeding with this project, i.e., the subsequent issues relating to the final YESAB report and decision body approval delays were not foreshadowed in the draft.

- In contrast to the YESAB process, YOGA's requirements were being newly developed as the project proceeded – and the directions that created requirements for last minute material and costly changes in the project could not reasonably have been foreseen based on established Canadian criteria applicable to similar projects.

TOPIC: **Battery Project**

REFERENCE:

PREAMBLE: It is unclear from the GRA which battery option is preferred. A 4.6MW or 8MW lead acid or an 8MW Li ion option are all on the table.

QUESTION:

a) Please present: the capacity of these options, the energy available and for how long, the capital costs, the cost per MW and MWh and the discussion around arriving at a decision.

b) If a 15MW battery had been in place, the four grid failures of July/August 2017 may have been avoided. A 15MW battery would reduce or even eliminate the need for spinning reserve, preserving water for winter months. Why is the maximum battery size proposed for Takhini 8MW rather than 15MW (adequate to replace the #4 turbine at Whitehorse)?

c) Battery prices are falling by about 15% per year. The most expensive option identified is $27.4M, and its replacement cost is estimated at $22.1M. This is a reduction of $5.2M or just under 20%. What are the underlying assumptions behind this estimate?

d) The cheapest option identified appears to be the 4MW lead acid at $21.7M and the most expensive is presumably the 8MW Lithium ion at $27.4M. On the face of it, this is a very modest difference (a doubling of capacity for a 28% increase in price). Will this remarkably flat price curve continue with larger battery packs?

ANSWER:

(a)

YEC has not made a final decision on the size of the Energy Storage System (ESS) or the preferred technology. All details requested in the question can be found in the TransGrid Solutions Inc. report located in Appendix 5.19 of the 2016 Resource Plan. This document is publicly available at the link below. Links to the 2016 Resource Plan Appendices are provided in YUB-YEC-1-83(e).

http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.19_Evaluation_of_Energy_Storage_Technologies_(Transgrid_Solutions_2016).pdf

(b)

It is not possible to assume a battery of any size would have avoided the grid failures mentioned; other factors such as the location of the fault on the grid relative to the battery and the load also affects whether this supply source would be available in the specific circumstance.

As part of the planned 2017 and 2018 activities, YEC will confirm the size of the Energy Storage System and preferred technology. Details supporting the size of the ESS considered in the TransGrid Solutions Inc. report can be found in Appendix 5.19 of the 2016 Resource Plan. This document is publicly available at the link below. Links to the 2016 Resource Plan Appendices are provided in YUB-YEC-1-83(e).

http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.19_Evaluation_of_Energy_Storage_Technologies_(Transgrid_Solutions_2016).pdf

(c)

Underlying assumptions behind the estimate of the various ESS options are detailed in the TransGrid Solutions Inc. report that can be found in Appendix 5.19 of the 2016 Resource Plan. This document is publicly available at the link below. Links to the 2016 Resource Plan Appendices are provided in YUB-YEC-1-83(e).

http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.19_Evaluation_of_Energy_Storage_Technologies_(Transgrid_Solutions_2016).pdf

(d)

YEC is keeping appraised of the evolution of prices for energy storage systems. As part of the planned 2017 and 2018 activities, YEC will request new cost estimates to reflect the latest market conditions. Any stipulation on the shape of the price curve of energy storage systems would be speculative at this time.

TOPIC: **Southern Lakes (Marsh Lake) Enhanced Storage**

REFERENCE:

PREAMBLE:

QUESTION:

a) Why has the estimated cost of the Marsh Lake Storage risen from $4M to $17M?

b) What does YEC anticipate paying to waterfront homeowners for mitigations for shoreline erosion, landscape architecture, septic system retrofits, etc.

c) Please break down the mitigation costs for waterfront properties on Marsh Lake, Tagish Lake, Nares Lake and Bennett Lake.

d) How do mitigation costs affect the financial viability of the project?

e) Does YEC believe any of this mitigation is required and justified even if the Southern Lakes Storage Concept does not proceed? How would YEC propose that work and those costs be covered?

f) What is the threshold and analysis that YEC will use to determine if and when the project has no net economic benefit to ratepayers?

g) Please run the calculations without an assumption that YDC will pay for the project in the way it did for the LNG project.

ANSWER:

(a)

Please see the response to YUB-YEC-1-84.

(b)

Mitigation for potential erosion-affected shoreline areas would be constructed and maintained by Yukon Energy for the duration of the operations that utilize the expanded storage range. No payments are proposed to be made to property owners.

Mitigation for shoreline properties that have project-affected subsurface infrastructure, such as septic systems, would include the purchase and installation of various pieces of equipment by Yukon Energy via qualified contractors. The installed equipment would then become the property and responsibility of the infrastructure owner. In some cases, the mitigation solution may involve on-going operational costs, such as additional electricity for sump pumps that would operate more frequently than without the project. In these circumstances property owners would be provided a one-time cash payment equivalent to the incremental cost of infrastructure operation for a 25-year period. Additional payments for such infrastructure operation would not be extended to any future licence renewal periods or in the case of property ownership changes.

(c)

The preliminary project effects assessment has identified a requirement for mitigation to be implemented at several properties on Marsh Lake and near the outlet of Tagish Lake. No potentially significant adverse effects are predicted for other parts of the Southern Lakes, although a detailed monitoring program would be implemented to track this. As such, no further mitigation for these areas is proposed. The following table provides a breakdown of the estimated mitigation costs for waterfront properties on Marsh Lake and Tagish Lake. Table 1 presents the summary of the mitigation costs for the Southern Lakes Enhanced Storage Project (SLESP).

Table 1 – Summary of Mitigation Costs for SLESP by Geographic Locale

Mitigation Category	Marsh Lake	Tagish Lake
Shoreline Erosion Protection	$4.0 million	$2.0 million
Sub-surface Infrastructure	$1 million	$0
Heritage Resources Protection/Recovery	$75,000	$75,000
Post-Implementation: (i) Monitoring (ii) Operational Costs, and (iii) Adaptive Mgt. Contingency	 $1.8 million $0.8 million $3.4 million	

(d) and **(f)**

Consideration of the planning costs to date along with those forecast to complete the remaining planning, assessment, permitting, and construction of the Project inform routine decision-making intervals regarding whether to continue to advance the project. It is reasoned that a suitable stop point for this project would be when such power benefit and economic analyses predict a levelized cost of energy greater than that of the next comparable firm energy project. Non-financial factors could also affect the decision to proceed (e.g., as in the Gladstone storage project, if YEC is not able to get key stakeholder support, the project would not be advanced).

To date, the estimated costs (and technical feasibility) of project mitigation have not resulted in rendering the Project non-viable. See also response to YUB-YEC-1-84.

(e)

If the Southern Lakes Enhanced Storage project does not proceed, YEC does not believe it has liability for mitigation.

(g)

The existing business case analysis does not assume, in any way, that YDC will pay for this project.

TOPIC: **Mayo Lake Enhanced Storage**

REFERENCE:

PREAMBLE: This project has been found to be non-viable because the outlet to the lake is silting up. Reservoir siltation is a normal feature of hydro projects.

QUESTION:

a) What is planned to address this issue and what is the cost?

b) How long will it take for siltation to affect the viability of this project again?

ANSWER:

(a)

Please see the response to YUB-YEC-1-85(c).

(b)

There are several factors that could affect the rate of future aggradation of the channel following initial dredging such that project viability would potentially be affected. The remaining engineering studies will seek to understand the mechanisms and processes that are causing the aggradation. As a consequence, Yukon Energy plans to develop a suitable engineering design to remove the sediment and minimize the frequency of future re-dredging.

TOPIC: **Gladstone Project**

REFERENCE:

PREAMBLE: The Gladstone project included a diversion of water between watersheds, which requires several significant authorizations from DFO and from First Nations. Predictably, these authorizations did not materialize, so this project is effectively dead. The 2017 GRA identifies $4.521M to be added to the rate base for this project.

QUESTION:

a) Please explain how the difficulties in permitting were not identified in advance of the work done.

ANSWER:

(a)

YEC was aware of the permitting challenges at the time of project initiation. Notwithstanding this risk, the forecast cost to execute the project would have resulted in very affordable energy for the grid particularly in winter.

The YUB has previously reviewed this justification and concurred that pursuit of this extra water made sense as long as there is economic benefit to ratepayers [YUB 2013-01, Reasons for Decision, p.344]. YEC at that time stipulated that ongoing work would be conditional on securing First Nation support for the project.

As both affected First Nations have indicated that they will not support the project, YEC has concluded there is very low probability that the regulator will approve this project and therefore it is not logical to continue with the project at this time.

TOPIC: **Future Thermal Capacity Project**

REFERENCE:

PREAMBLE:

QUESTION:

a) Please explain why the LNG option is now being explored for this 20 MW thermal capacity project (as discovered in the GRA Workshop presentation), and why these considerations were not included in the 2016 Resource Plan – which concluded without a doubt that diesel is the cheaper capacity choice of the two thermal options.

b) Is LNG back on the table for the 20MW capacity project because of possible mining loads being added to the system, and as a result, a new 20MW LNG facility would be used as an energy project to service industrial mining loads?

ANSWER:

(a)

At this time, YEC has not made any decision on the primary fuel of the potential thermal plant facility.

As presented in YEC's 2017-2018 GRA Application, YEC is examining the option of a new greenfield thermal plant and the option of refurbishing the existing Whitehorse Diesel Plant, which has LNG storage and processing facilities in place, with dual fuel engines. Please see the response to YUB-YEC-1-79(c) and to John Maissan-YEC-1-32(a).

Since completing the 2016 Resource Plan, YEC was made aware of the potential development of an LNG depot near Whitehorse. The availability of local LNG storage would enable the removal of the storage and processing facilities from the scope of a greenfield thermal plant. Consequently, it could make a new natural gas fired generating plant financially more attractive and bring its Levelized Cost of Capacity close to that of a greenfield diesel plant. Part of the planned activities for 2017 and 2018 will assess the impact of removing the LNG storage and processing equipment from the scope of the plant and its impact on the business case.

Please see also response to YUB-YEC-1-79(b).

(b)

Please see response to (a) above, which indicates the basis for reassessment of the LNG options without regard to any change in mine loads.

The portfolio analysis completed as part of the 2016 Resource Plan showed thermal assets would be relied upon to primarily meet capacity under the single (N-1) contingency criterion. To a lesser extent, they would be used to support system energy requirements until such time as new renewable resource options could be brought online that would offer least cost solutions (2016 Resource Plan, Chapter 8, Section 8.2.7, PDF page 369). Access to adequate LNG capability during this period would help to reduce the long term average thermal generation cost requirements.

TOPIC: **DSM**

REFERENCE:

PREAMBLE: The YUB disallowed most of the proposed DSM program presented at the last GRA. YEC's analysis of the allowed programs (inCharge) indicates that they are very cost effective. AEY has nonetheless withdrawn from the program.

QUESTION:

a) Please explain how YEC is repackaging its DSM program to comply with the current YUB directives (including the stipulation that YEC and AEY jointly submit the proposals).

b) If these programs are as cost effective as indicated, please provide an analysis of why they were not as cost effective for AEY.

c) How will YEC's approach to DSM be different to address the capacity shortfalls?

ANSWER:

(a)

YEC and AEY jointly filed the 2013 Demand Side Management Program Portfolio as a part of AEY's 2013-2015 General Rate Application. Since that GRA was approved, YEC has executed the DSM program in accordance with YUB direction. YEC plans to continue the delivery of the approved inCharge program for the test years, as long as program results reach targets established by the Board. Starting in 2018, YEC plans to start the development of new DSM programs, including peak load reduction programs. The design of these programs are expected to follow the DSM program planning process outlined in Section 1.2 of the 2013 Demand Side Management Program Portfolio. Further explanation of current and future DSM programming can be found at YUB-YEC-1-80.

(b)

YEC has not conducted a cost-effectiveness analysis of the DSM programs on behalf of AEY.

(c)

As the work done on DSM to date has focused mainly on energy DSM, YEC will also perform a Capacity DSM Feasibility Study to quantify the potential cost and achievable uptake of capacity focused DSM programs. The DSM program planning process is outlined in response to YUB-YEC-1-80(g).

TOPIC: **Integrating Renewables**

REFERENCE:

PREAMBLE:

QUESTION:

a) Please describe the planning for a smart grid to manage home based PV systems, ETS, EVs and home based battery storage.

b) As more and more customers become providers of electricity as well as consumers, it is logical to assume that net sales of electricity by YEC will drop. Please provide an analysis of the effect on sales of electricity from the micro generation and the IPP programs.

ANSWER:

(a)

At this time, the impact of photovoltaic (PV) systems, electric thermal storage (ETS), electric vehicles (EVs) and home battery storage is negligible on the existing grid. In the 2016 Resource Plan, the impact of PV, ETS and home battery storage is accounted for through allowance for microgeneration; EV's are separately provided for in the forecast. As a part of the continuous preparation process for each resource plan update, YEC plans to monitor factors influencing penetration of PV systems, ETS, EVs and home battery storage and plans to address any new information as part of that ongoing update process as it becomes available.

(b)

At this time, the impact of home providers of electricity is negligible on the existing grid.

As a part of the continuous preparation for an update of the resource plan, YEC monitors factors influencing penetration of home providers of electricity. As for the independent power producers, YEC will consider them on one-to-one basis and make adjustments if needed.

TOPIC: **Transmission Line Vegetation Management**

REFERENCE:

PREAMBLE: YEC proposed to switch from mechanical brushing to herbicide treatment of brush under much of is transmission lines. After the public raised concerns, YEC contracted Yukon College to investigate more deeply the issues around using herbicides and to explore other vegetation management options.

QUESTION:

a) Please provide a copy of the Yukon College study.

ANSWER:

(a)

Please see response to John Maissan-YEC-1-14(a).

TOPIC: **Stewart-Keno Transmission Line and Mining Loads**

REFERENCE:

PREAMBLE:

QUESTION:

a) What is YEC's business case for the significant public investment in this transmission line?

b) How does YEC plan to provide electrons to existing and potential new industrial customers?

c) In YEC's 20-year Resource Plan, the values survey indicated that ratepayers held environmental concerns and considerations in the highest regard. How does YEC anticipate reconciling the wishes of ratepayers for renewable energy, and the possibility that industrial loads will be met with LNG generated electrons?

ANSWER:

(a), (b) and **(c)**

The Stewart-Keno Transmission Line project with extension of the 138 kV grid from Stewart Crossing to Keno City, which would materially expand the Yukon hydro grid capability to accommodate future loads as well as new resource options, is conditional today on government rather than ratepayer funding given current and potential loads to be supplied at this time.

A new line from Mayo to the Keno region, however, is required to replace the end of life existing 69 kV line constructed in the 1950s. The option is to have users in this region (mines, as well as non-industrial electricity users) depend solely on local fossil fuel generation. The business case for replacement of this existing line would be strengthened by additional loads required by any major industrial customers in this region. As in the past, the required generation would be supplied by the Mayo hydro facility supplemented by generation from the southern portion of the Yukon Integrated System, and any new renewable generation on the northern portion of the grid.

Providing grid generation to supply new mine loads is expected to enable utilization of existing renewable hydro generation capability, as well as potential development opportunities for enhanced renewable generation, to displace diesel and/or LNG generation that would otherwise be required if on-site power supply was required for these mine loads. In the event that LNG generation on the grid is required for a portion of the required supply, the net impact will continue to be a reduction of GHG emissions compared to the option of relying only on use of on-site power for such industrial loads.

Please also see response to YUB-YEC-1-76.