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In the Matter of the Yukon Utilities Board review, as directed by the Minister of Justice, of an Application by Yukon Energy Corporation under Part 3 of the *Public Utilities Act* for an Energy Project Certificate and an Energy Operation Certificate regarding the Proposed Whitehorse Diesel-Natural Gas Conversion Project

OPENING STATEMENT

YUKON ENERGY CORPORATION

March 31, 2014

Overview

Mr. Chair and members of the panel, Yukon Energy welcomes the opportunity today to be in front of the Yukon Utilities Board for your review of the Whitehorse Diesel-Natural Gas Conversion Project Application that Yukon Energy has filed with the Minister of Justice for Energy Certificates under Part 3 of the *Public Utilities Act*.

The Project will modernize Yukon Energy's Whitehorse Thermal Generating Station and provide reliable and flexible thermal generation on the Yukon grid, with the conversion of diesel generation units scheduled for retirement to cheaper and cleaner burning natural gas-fired generating units supplied by liquefied natural gas (LNG) delivered by truck from British Columbia or Alberta.

The Project scope involves replacing two end of life diesel generating units (WD1 and WD2) scheduled for retirement in 2014 and 2015 in the existing Whitehorse diesel plant, with:

- Three new modular natural gas-fired generating units to be located adjacent to the Whitehorse plant site - overall, replacing 9.1 MW of end of life diesel generation with 13.1 new gas generation; and
- The installation of LNG truck offloading, storage, vapourization and related infrastructure.

To accommodate the new facilities required for the Project, Yukon Energy will acquire approximately 0.9 ha of Public Utility zoned Yukon Government lands and create access and utility crossings at various locations along the 0.6 ha of privately held railway right of way, adjacent to the south of the existing Whitehorse Thermal Generating Station site.

The first two natural gas-fired units (8.8 MW total capacity) are to be in service before the end of 2014 to provide capacity and fuel cost savings during the winter of 2014/2015. The third unit (4.4 MW) is planned to be installed as required to meet grid capacity planning requirements, likely by late 2016. The estimated capital cost for the Project is $40.9 million, with $36.5 million for the initial phase to be completed by the end of 2014, and the balance of $4.4 million when the third natural gas-fired unit is installed.

The primary need for the Project is related to capacity, that is, it is needed to meet Yukon Energy's capacity requirements for the Yukon grid.

However, there is also an opportunity to utilize cheaper natural gas to replace incremental winter diesel requirements and benefit both the environment and ratepayers.

Current YUB Review

The purpose of the current YUB review and hearing is to provide the Minister with the Board's report and recommendations on:

- The public need for the Project under various reasonable electric load forecasts and the effect of the Project on rates of customers;
- The capability of existing and currently committed generation and transmission facilities to provide reliable electric power generation to meet the forecast load requirements and YEC capacity planning criteria;
- Alternatives to the Project given reasonable load assumptions;
- The risks facing the Project and their potential impacts on rates for customers; and
- Whether it is prudent to build the Project at this time.

The Application and responses to approximately 580 information requests from the Board and intervenors address these matters and demonstrate:

- The clear need for the Project at this time;
- The robustness of the Project's economics given a number of sensitivity tests; and
- The material savings expected to ratepayers over the Project's economic life.

Yukon Resource Planning Context

The 2006 Resource Plan indicated that as of 2006, Yukon Energy faced significant pending capacity shortfalls on the WAF grid related to the adoption of the new capacity planning criteria, as well as the planned retirement of WD1, WD2 and WD3 in combination with ongoing load growth. Yukon Energy initiated a series of activities to address these potential shortfalls, including re-commissioning of FD1 and planning for the staged refurbishment of up to three Mirrlees units at Whitehorse (totaling 14 MW) over the period to 2012, commencing with refurbishment of WD3 in 2007.

The 2006 Resource Plan also provided the foundation for Yukon Energy to pursue over the past decade major renewable grid enhancement Projects. By the end of 2011, completion of the Carmacks-Stewart Transmission Project connected the WAF and Mayo Dawson grids and completion of Mayo B and Aishihik Third Turbine expanded Yukon Energy's hydro generation capability with ongoing reductions in diesel generation.

In 2011, Yukon Energy continued its resource planning process.

Discussions with stakeholders and the public about energy choices, including the need for backup thermal capacity for the Yukon's isolated hydro based system, continued as part of a three day Energy Charrette.

One of the supply options examined at the Charrette was LNG.

The Charrette planning process led to the definition and adoption of four criteria for evaluation and decision-making that were used to assess supply options in the 2011 Resource Plan: reliability, affordability, flexibility, and environmental responsibility. Following the Charrette, Yukon Energy continued to host technology-specific workshops, including a public workshop in January 2012 on the potential use of LNG for electrical generation. Subsequent to this, the Overview to the 2011 Resource Plan was made public in July 2012 during YEC's 2012/2013 GRA review by this Board.

Building on the Charrette process, the 2011 Resource Plan reviewed a wide range of near term and longer term supply options against a number of grid load scenarios and identified the critical need for resource options to be both flexible and reliable in the near term in order to address changing load and supply conditions on the isolated Yukon grid.

Today, notwithstanding increased hydro generation capabilities and the absence of new mine loads being connected to the grid, ongoing load growth on the Yukon grid has depleted the surplus hydro available since the 1998 Faro mine shutdown.

Based on long-term average hydro generation and current loads, and notwithstanding the extensive investments made in renewable energy projects over the last ten years, diesel generation has once again become the default option to meet current energy and capacity requirements on the Yukon grid until long term loads are sufficient to support other economic new renewable generation. Diesel generation costs are also once again included in rates based on long-term average hydro generation.

Need for the Project

The need for the Project is driven by a forecast grid capacity shortfall of 7 MW by the start of 2015, 10.9 MW by the start of 2017 and 17 MW by the start of 2019.

These forecast grid capacity shortfalls reflect forecast non-industrial peak winter load, reserve capacity needed to meet N-1 risk (loss of Aishihik line) and the firm winter capacity capability of existing and currently committed generation and transmission. The fact that WD1 and WD2 are end of life in 2014/15 removes 8 MW of derated capacity at Whitehorse and drives the need for 7.0 MW of new capacity by the start of 2015.

The Project's initial 8.8 MW of new gas-fired generation to be in service by the start of 2015 will meet this capacity shortfall need. The third 4.375 MW gas-fired unit is currently expected to be in service by the start of 2017 to meet the capacity shortfall need forecast at that time.

This need also results in an opportunity to modernize the existing Whitehorse diesel plant with gas-fired generating units that are cleaner burning and cheaper to run than diesel units – benefiting the Yukon environment and ratepayers.

Capability of existing and currently committed facilities

WD1 and WD2 have been in service for 46 years and are now at end of life.

Plans for the retirement of these units have been in place as far back as the 1992 Resource Plan hearing. In the past, retirement could be deferred due to the material surplus hydro generation available on the WAF grid after the closure of the Faro mine in 1998, the re-commissioning of FD1 and refurbishment of WD3, and the expectation that the WD1 and WD2 units would not yet be needed to meet grid capacity requirements.

Retirement of these Whitehorse diesel units can no longer be delayed – and maintaining these units in service beyond the end of 2014 in their current condition is not an option.

In planning for the future, it is also relevant to recognize that the remaining five diesel units at the Whitehorse plant are all planned to be retired within the next 13 years - and that ongoing modernization of this key facility at Yukon's largest load centre will be needed over this period.

Alternatives to the Project

No feasible renewable resource alternatives to the Project have been identified.

Renewable Options do not meet present capacity requirements

Potential near term hydro enhancement projects such as Mayo Lake and Marsh Lake Storage are estimated respectively to supply 4 and 6 GWh (long term average) incremental energy supply to the grid. However, these hydro enhancement options will not meet the identified need (today or in the future) for new, flexible and reliable capacity. Greenfield renewable options (such as wind or hydro) are being considered for future development when higher and longer term grid energy loads can justify such developments – however, such options do not provide reliable, flexible capacity to meet the grid's backup capacity requirements.

Refurbishment of WD1 and WD 2 is not an option

WD 1 and WD 2 are at end of life. They are 46 years old and without major refurbishment can no longer be relied upon for backup capacity.

In 2006 Yukon Energy considered refurbishment of end of life diesel generation as a potential cost-effective option to ensure continued reliable capacity on the grid. However this option was only considered possible after receiving guarantees of continued support for the refurbished engines from the manufacturer (MAN) including the continued availability of spare parts and technical support. At the time YEC elected to focus on FD1 and WD3 in order to gain experience, and deferred expenditures on the other Mirrlees units until there was a confirmed need to meet a forecast capacity planning shortfall.

Unfortunately YEC experience with the refurbishment of WD3 and FD1 has demonstrated that the promised support from MAN was in fact not available and after-market part suppliers and technical support is terribly unreliable. Long delays and significant problems in ordering parts, material issues with quality control and lack of component technical support mean that refurbishment of these 46 year old engines is not feasible and they must now be replaced.

In short, refurbishment of the WD1 and WD2 units is not an acceptable option today to meet the current capacity shortfall.

New diesel generation is the only other feasible option

New higher efficiency diesel generation installed in the WD1 and WD2 service bays at the Whitehorse Diesel Plant was determined to be a feasible and cost effective option to meet the current capacity shortfall on a grid with forecast long-term average default diesel generation requirements today, and this alternative was therefore used in the Application to assess the prudence and cost effectiveness of the Project.

Overall, although the Application shows that replacing the old diesel units with new and more efficient diesel units would have incrementally lower capital costs compared to new gas-fired generating units, the opportunity to meet the Yukon grid's capacity shortfall with new, cleaner burning and cheaper operating gas-fired units means that the Project is by far the superior and most cost effective option.

Secure LNG Supply

In addition to the capacity needed on the Yukon grid, a second pre-requisite for the Project is a secure supply of LNG that can be trucked to Whitehorse from BC or Alberta.

At the time of Yukon Energy's January 2012 LNG workshop the only identified potential sources for near-term LNG supply to Yukon were LNG export developments planned at Kitimat, an announced Shell Canada LNG plant planned in Calgary, and a potential future LNG facility development at Fort Nelson, BC.

Working with Western Copper & Gold, Yukon Energy in early 2012 carried out a Request for Interest Proposal process which led to a proposal from Shell Canada to supply YEC with LNG from its Jumping Pound LNG plant to be opened in Calgary in 2014. YEC subsequently worked with Shell Canada to finalize by early 2013 the LNG supply agreement outlined in the Project Application submitted to the Minister in December 2013.

During 2013 Yukon Energy was informed of delays in planned construction of the Shell Jumping Pound facility construction from summer 2013 to late fall, and as a result contingency planning for a delay in the Shell plant in Calgary beyond Q4 2014 had been underway since fall of 2013. Although formal termination of the agreement has not yet occurred, on February 19, 2014 Shell senior officials informed Yukon Energy that notwithstanding construction on the site had been commenced and material equipment purchases had been made Shell had decided to not proceed with the Jumping Pound facility at this time. Although Yukon Energy reviewed its contingency plans in the IR responses filed at the end of February it chose to wait to update the Board and the parties on the Shell situation until after it had fully absorbed the Shell decision and had in place a confirmed alternative LNG supply plan.

The March 27, 2014 update explained Shell's decision not to proceed with its Jumping Pound LNG plant, and set out the following revised plans by Yukon Energy to secure LNG supply for the Project:

- **LNG supply from FortisBC**: Yukon Energy will now secure LNG supply from the FortisBC LNG facility at Tilbury (Delta BC) until such time as a lower cost source of LNG is available.
    - Yukon Energy has met with FortisBC and has confirmed that ample LNG supply is available to meet Project requirements from the operating FortisBC facility at Tilbury, including supply from existing facilities during 2015 and supply from the next major expansion that has BC Government regulatory approval and is planned to start operation in 2016.

- The rate for supply from Fortis will be based on the regulatory cost-based price under BCUC approved Rate Schedule 46 (approved in accordance with a direction to the BCUC from the BC Government as set out in OIC 557-13).

- **LNG supply chain development & optimization with NT Energy:** Yukon Energy is coordinating plans with NT Energy (who is currently securing LNG from FortisBC at Tilbury for use at Inuvik) to utilize NT Energy's Tridem units until such time as A-Train units are permitted. Yukon Energy and NT Energy are also exploring how joint cost savings with A-Train units can be secured once they are permitted.

- **Other potential near-term LNG supply options:** YEC is working with NT Energy on other potential near term lower cost LNG supply options that could be located closer to Yukon, including potential options with AltaGas and Ferus as noted in the March 27, 2014 update. Overall, the interest in near term LNG domestic supply development has grown considerably in the last 12 months in both Alberta and B.C., including potential facilities in Edmonton, Grande Prairie, Dawson Creek and Fort Nelson.

In short, Yukon Energy has access to a secure LNG supply at a price level that is not materially different than the Shell Agreement.

Project Economics - Overview of Expected Ratepayer Savings

The economics of the Project focus on three key comparisons with the only other feasible alternative new diesel:

- Capital costs;
- Fuel costs per kW.h; and
- Volume of diesel displaced by the Project.

Project Capital Cost Estimates

There is no material difference in terms of equipment costs new gas or diesel generation units. The primary capital cost difference between the new alternatives is the requirement to establish new facilities needed for LNG truck unload, storage and vapourization. As reviewed in the Application and responses to IRs, important elements of these LNG facilities will have the capability to support up to 30 MW of gas-related future generation capacity at the Whitehorse Thermal Generating Station.

The capital cost estimates included in Table 4-3 of the March 27, 2014 update filing show $36.5 million for the Project to the end of 2014, and $5.5 million for the third engine in 2016 (including an added contingency of $1.1 million), compared with $32.7 million for the New Diesel Alternative assumed to be completed in two stages over 2014 and 2015.

The updated capital costs estimate reflects Yukon Energy's response to YUB-YEC-1-1(d), which showed an increase from the $34.4 million May 2013 estimate originally included in the Application to $36.5 million. The updated estimates:

- Reflect the outcomes of tenders and RFPs carried out for engineering, project management, LNG plant and equipment, and transformer equipment.
- Include $1.0 million in contingency for construction contracts not yet awarded.

On March 19, 2014 the YESAB draft screening report was issued, recommending to the Government of Yukon, the Decision Body, that the Project be allowed to proceed without a review, subject to eight terms and conditions recommended in the report. The Executive Committee noted that the relatively few recommendations in its report are indicative of the comprehensiveness of Yukon Energy's commitments. Except for the recommendation to install underground power distribution lines (which YEC will discuss and seek to have revised), Yukon Energy's current plans accommodate all of the YESAB DSR recommended terms without any discernible adjustment to design or costs. Public comment on the DSR is expected to close by April 22, 2014 and, on this basis, a final YESAB recommendation is still expected by about the end of April.

Release of a positive YESAB DSR means that Yukon Energy's mid-May estimated construction schedule is on track and, subject to formal completion of the YESAB and Decision Document and permit processes, effectively mitigates one of the remaining risks to capital costs, i.e., cost impacts from delays in construction. Yukon Energy continues to work cooperatively with YESAB and the relevant Yukon Government officials to ensure that the mid-May schedule is met.

Further, in order to protect overall Project construction schedule, tenders for the civil construction contracts have also now been issued.

Project Fuel Cost Savings per kW.h

The update filed March 27, 2014 shows estimated fuel cost saving in 2015 at 12.3 c/kW.h of generation for gas versus new diesel and 16.8 c/kW.h for gas versus other diesel on the grid.

Focusing on the updated fuel cost savings per KW.h for 2015, the following are noted:

- Updated diesel fuel costs reflect average diesel price to YEC at Whitehorse for the latest six months as reviewed in IR responses.
- Updated LNG costs reflect updated haul costs;
- The assumed AECO gas price of $4.50/MMBtu is retained. It is still considered a conservative assumption based on the average of AECO prices over the last six months (averaged $3.7/MMBtu as reviewed in IR responses).

The updated fuel cost saving per kW.h has not been materially impacted by the change in LNG supply to the existing FortisBC plant at Tilbury.

The material fuel cost saving for gas versus diesel is forecast to be sustained in North America over at least the next two to three decades. Aside from US Energy Information Administration (EIA) long term world crude oil and US natural gas price forecasts reviewed in the Application and in IRs, active ongoing consideration of various LNG export opportunities from British Columbia to Asia as well as development of new LNG production facilities in western Canada to supply domestic markets, reflect key stakeholders (including the B.C. Government) expectations that the major gap between North American natural gas prices and world crude oil prices (on an equivalent price per Btu basis) will likely be sustained for the next 20 years or more into the future.

Overall Ratepayer Savings and Risks with the Project

Table 4-3 in the Application, as updated March 27, 2014, illustrates that added capital costs of $9.3 million for the Project compared with the New Diesel Alternative, including an added $1.1 million cost contingency for the third gas engine, are forecast to be fully paid off within the first four years of the Project operation through annual fuel cost savings.

Given that Yukon electricity rates are based on long-term average hydro generation (Board Order 2013-1), projected ratepayer fuel cost savings from the Project over the four initial years approximate $11.9 million using the conservative Base Case load forecast with no Alexco load.

These fuel cost savings are well in excess of the projected capital cost charges of approximately $2.7 million for the Project compared to new diesel, resulting in overall ratepayer savings exceeding $9 million over that time period including $1 million in 2015 alone.

Projected fuel cost savings of $11.9 million in the first four years are also in excess of the $9.3 million additional capital costs assumed for the Project compared to the New Diesel Alternative which means that the Project's added capital costs are projected to be fully recovered during these initial four operating years.

The Application demonstrates that the Project's economics and ratepayer cost savings are very robust, confirming that ratepayer cost savings would be sustained under a wide range of possible scenarios including material capital cost increases, reductions in fuel cost savings and changes in diesel generation forecasts.