

YUKON ENERGY CORPORATION

APPLICATION FOR AN ENERGY PROJECT CERTIFICATE
AND AN ENERGY OPERATION CERTIFICATE REGARDING THE
PROPOSED WHITEHORSE DIESEL-NATURAL GAS CONVERSION PROJECT

ROUND 1 INTERROGATORY RESPONSES FILED

February 27, 2014

City of Whitehorse
(CW)

TOPIC: **City of Whitehorse Concerns**

REFERENCE: **City of Whitehorse Letter of January 10, 2014 to the Yukon Environmental and Socio-economic Assessment Board ("YESAB")**

PREAMBLE:

In its letter of January 10, 2014 addressed to the YESAB, the City's Development Review Committee ("DRC") raised a number of concerns with the YEC proposal. A copy of the letter is attached to this request. The City requires an understanding of YEC's response to the City's concerns.

QUESTION:

a) In paragraph 3 of page 1, the City expressed concern with proposed screening along Robert Service Way. Please fully discuss YEC's response to the City's concerns, and provide YEC's proposed solution(s) to the concerns.

b) In paragraph 4 of page 1, the City advised that underground lines would be required. Please confirm that only underground lines will be used. If not confirmed, please fully explain how YEC will comply with the City's requirements.

c) In paragraph 5 of page 1, the City expressed concern with the use of gravel roads. Please fully explain all actions that YEC will undertake to ensure that it is fully compliant with all City requirements.

d) In paragraph 6 of page 1, flowing onto the top of page 2, the City discusses formal access and utility easements. Please fully discuss all formal agreements and easements that YEC has, or will be securing prior to commencing the project.

e) In first full paragraph of page 2, the City discusses an active transportation and leisure path that may be disrupted during construction. Please confirm that development of an LNG facility, if approved, will not impact the continued use of this right of way. If not confirmed, please explain fully, including how YEC will

mitigate any impacts and what plans, if any, YEC has to address this matter with the City.

f) In the second full paragraph of page 2, the City discusses a surface water exfiltration/evaporation pond that will be disrupted by the development. Please provide YEC's plans for the reconfigured surface drainage area that will be required. Please also confirm that the drainage pond will be accessible by City crews for maintenance purposes. If not confirmed, please fully explain.

g) In the third full paragraph of page 2, the City discusses fire suppression services. Please provide YEC's plans to extend fire suppression services to the location of the proposed project.

h) In the fourth full paragraph of page 2, the City requested confirmation that the existing YEC heating demands will be sufficient to use all gas which may turn from liquid to gas. Please provide the requested confirmation. If confirmation is not provided, please fully explain.

i) In the fifth full paragraph of page 2, the City expressed concern about air quality. Please provide all analysis that compares the impact of the use of LNG turbines on the air quality of downtown Whitehorse to the air quality arising from the use of diesel turbines.

j) In the fifth paragraph, the City also discusses noise pollution. Please fully discuss all possible noise impacts, including the impact of each of trucking, unloading, vaporizers, running of turbines, and any other sources of noise of the new facility, compared the noise levels that are currently produced and impact the citizens of Whitehorse. Include in the response a confirmation that the noise produced by the existing diesel generators is more than the noise that will be produced by the new gas turbines.

k) In paragraph 1 of page 3, the City discusses the use of waste heat. Please fully explain how waste heat will be captured and used.

l) In paragraph 2 of page 3, the City indicated its understanding that the new turbines would only be used to meet peak demands and would not be used on a

continual basis. Please provide confirmation of the City's understanding. If confirmation cannot be provided, please fully explain.

m) Please confirm that YEC does not see LNG as an alternative to or as replacing renewable energy generation in the Yukon. If not confirmed, please fully explain.

ANSWER:

(a)

Although the Project will result in the establishment of a permanent energy production facility on the site, the Project is consistent with City of Whitehorse Zoning for the Construction Footprint.

To mitigate visual quality effects, a fence and vapour barrier will be installed that will partially screen the view of the facility and equipment from Robert Service Way and Miles Canyon Road. A vegetation buffer approximately 6 metres in width along Robert Service Way and 3 metres in width on the access road will be maintained along the perimeter of the Expanded Site Area. Landscaping will be undertaken at the end of the construction phase and will comply with relevant City of Whitehorse zoning bylaws.

(b)

Yukon Energy is aware of the City's concerns regarding overhead power supply/distribution lines connecting the substation to the proposed site and the City's desire for an underground line solution. It is noted that underground distribution lines are more costly than overhead lines, and Yukon Energy will ultimately need to balance the concerns raised by the City and cost considerations in final design.

(c)

The access road around the LNG storage facility will be paved around the intersection of the existing roads to the new access roads up to a couple of meters inside YEC access gates to reduce gravel migration to paved roadways.

(d)

Yukon Energy is in the process of securing formal access and utility easements from Whitepass for crossing the railway right of way. Yukon Energy does not expect that these easements will require approvals by Transport Canada. Site access and utility crossings are also not expected to affect the railway line.

The Project will be developed in accordance with existing regulatory requirements, including requirements in CSA Z276-11 for certain distances from specific equipment or potential heat sources (in the event of a fire) to a property line that can be built upon. Yukon Energy is therefore also seeking "no build" easements from the City of Whitehorse and from Whitepass that will confirm that no buildings, roadway or other facilities or structures will be built upon the following:

1. City lands located between the Site and (a) the edge of the existing Robert Service Way pavement and (b) the edge of the existing Schwatka Lake Access Road pavement.

2. Whitepass lands within the Expanded Site Area between the existing rail line and the Yukon Government land to be acquired by Yukon Energy for the Project.

Yukon Energy has provided documentation to each of Whitepass and the City of Whitehorse and is in the process of discussions with these parties to secure the necessary easements.

(e)

The YESAB Project Proposal (Section 7.4.2.1) notes that within the Project Construction Footprint, approximately 0.5 km of the 15 km Yukon River Loop trail will be affected by the Project during the construction phase. However, effects of the Project after mitigation measures outlined in the YESAB Project Proposal are expected to be small and limited to the immediate Project Construction Footprint in extent. Further, the Loop trail will be fully functional once construction is completed[1].

[1] At present, the first 1 km of this trail runs along Robert Service Way from the Robert Service Campground to the Project Construction Footprint area. The trail then traverses the Project Footprint area for approximately 0.5 km before connecting to Miles Canyon Road. Effectively this portion of the trail is the actual Yukon Energy access road off Robert Service Way and the Miles Canyon Road.

Construction areas will also be delineated with fencing and signage to ensure that during construction any continued recreational uses in the vicinity will occur in a manner that will maintain the safety of the public and the construction staff. All access to the Project Construction Footprint will be via existing transportation routes (Robert Service Way and Miles Canyon Road) and will not disrupt the recreational uses in the surrounding area. Similarly, transport of the LNG to the facility during operations will use existing transportation routes (Alaska Highway and Robert Service Way) and will not disrupt recreational uses in the area.

(f)

The final location and design of the storm water retention pond will be determined in collaboration with the City and applicable regulators as a part of the detailed design to ensure it will be able to handle run off from the Project site and from Robert Service Way. It is anticipated that the drainage pond will be accessible by City crews for maintenance.

(g)

The design of the site will meet CSA standards and setbacks as well as requirements set out under the Yukon Gas Facilities Regulations. A number of fire suppression systems are integrated into the plant design including fire suppression extinguishers, fireproofing of critical structures located in process areas, designated restricted areas and management controls to minimize potential ignition sources in areas where flammable gas may be present.

Yukon Energy is continuing to consult with the Fire Marshall's Office and City of Whitehorse Fire Department as appropriate, including working towards development and implementation of an emergency firefighting training program.

(h)

Please see YUB-YEC-1-35.

(i)

Analysis regarding the impact on air quality of use of gas-fired turbines compared to diesel-fire turbines is fully reviewed in Chapter 7 of the YESAB Project Proposal (section 7.4.2.2) and in the following responses to supplemental information requests filed with YESAB:

- October 25, 2013 (R1[Performance specifications], R3 [conversion factors]).

- January 29, 2014 (R17 [greenhouse gases], R18 [greenhouse gases: constituent emissions factors] and R19 [other anticipated greenhouse gases). These responses updated Table 7.4 from the Project Proposal (Table A-1) with the updated air emissions (for GE 4.375 MW) as compared to alternatives (new and existing diesel engines).

Section 7.4.2.2 and the supplemental information requests filed with YESAB on January 29, 2014 are provided as Attachment 1 and Attachment 2 to this response.

(j)

Section 7.4.2.2 of the YESAB Project Proposal summarizes the impacts of the Project on noise and indicates that the Project will have a positive effect on noise levels (i.e., noise levels are expected to decrease compared to operation of the existing diesel engines or operation of new diesel engine alternatives). A summary of the assessment included in the YESAB Project proposal is noted below.

The nearest residence to the Project Construction Footprint is located approximately 500 m away, across the Yukon River in Riverdale. Baseline ambient noise levels were measured over a 5-day period in October 2012 at a monitoring location in close proximity to the nearest residence to the Project Construction Footprint, during a period when the existing Yukon Energy diesel generators were not running. Background noises were dominated by local traffic, the Yukon River, wind, dog and bird noises. Airplane traffic originating from the Erik Nielsen Whitehorse International Airport (Whitehorse airport) was a significant source of transient noise, typically lasting less than 5 minutes. The average daytime and nighttime noise measurements are indicative of a quiet residential neighbourhood.

During construction there will be increased noise produced by the Project on a somewhat continual daytime basis from the use of equipment on site that will include a loader, packer, dozer, excavator and trucks for earthworks; similar equipment for underground work and for surface finishes. Construction noise mitigation to minimize adverse effects will include compliance with applicable municipal requirements for construction hours and ensuring that all equipment maintains an operational muffler. The residual noise emissions for these activities are transient (i.e., these types of noise emissions no longer exist once construction equipment is no longer in use) and will be of similar character to existing traffic noise on Robert Service Way (low rating for magnitude). Additionally, the duration of these noise emissions will be limited to the period of construction (short duration) and the impact of the noise is not expected to be evident outside the Project Study Area. As a result, construction noise impacts are not expected to be significant.

During operations there will be noise generated by the Project as a result of operating the new natural gas engines. However, it is important to keep in mind that all Project alternatives considered in Chapter 6 [of the YESAB Project Proposal] (e.g., new diesel) also generate noise emissions when they are required to be run. As noted…, the current Project involves decommissioning of two existing diesel engines and replacing these engines with up to three new natural gas engines. After Project commissioning, when backup or peaking power is required, the new gas engines will be operated preferentially until additional capacity is required from the remaining diesel engines. The new natural gas engines will be located nearly twice as far from the nearest residential area as the existing diesel plant, and in closer proximity to commercially and public service zoned lands that are presently largely undeveloped under the approach path to the Whitehorse airport, where noise sensitive activities do not exist and are not expected to exist.

In addition, new natural gas engines will result in lower noise emissions than the existing diesel engines and lower than new replacement diesel engines.

(k)

Please see response to UCG-YEC-1-14(a) and YCS/LE-YEC-1-49(a).

(l) and **(m)**

Thermal generation (whether supplied by diesel or gas) is required on the isolated Yukon grid to meet all back up generation requirements (not just peaking requirements). This means that the new gas-fired generating units would be used to meet emergency back-up requirements, as well as grid loads during winter months and other periods when water availability for hydro generation is limited by seasonal or drought conditions or is otherwise insufficient to meet grid load requirements. Inability to rely on diesel generation in one or more of these circumstances would present an obvious and acute risk to human health and safety and public and private infrastructure, particularly during cold winter temperatures. In effect, the gas-fired generating units will serve the same purpose as diesel units on the grid and will be used in the same manner as the existing (or new) diesel units would be.

As has been its practice (and demonstrated by major recent renewable hydro enhancements at Mayo B and Aishihik, as well as by new transmission connection of the two hydro grids as well as transmission connection to Dawson City), Yukon Energy will continue to investigate and pursue new, renewable supply options that can be brought on line and used to displace energy that would otherwise need to be generated from fossil fuels.

As noted in the Application, Yukon Energy continues to pursue near term and longer term renewable options, including the following:

- **Potential near term hydro enhancements** (Mayo Lake Enhanced Storage Project and Marsh Lake Storage) which are estimated respectively (when developed) to supply 4 and 6 GW.h/year (long-term average) incremental energy supply to the grid.

- **Potential future options**, when higher long-term grid loads can justify such developments, include a 20 MW wind farm at Techo (also known as Ferry Hill) in the Stewart Crossing area, as well as potential future hydro generation at various potential greenfield sites.

clearing, grubbing, excavations). Standard best management practices for management of fugitive dust will be implemented as mitigation, such as sweeping or using a water spray on site access roads during construction if dust generation is persistent. The nature of this Project, with respect to expected fugitive dust emissions, is similar to many other construction projects that are completed every year within the City of Whitehorse. These projects have not caused exceedances of Yukon Ambient Air Quality Standards (YAAQS) and with appropriate mitigation it is highly unlikely that the current Project will cause such exceedances (small magnitude). In addition, any adverse effect extends only during the construction period (short duration). With appropriate mitigation the effect of the emissions is not expected to be evident outside the Project Study Area (medium extent). As such, the impacts of dust are not expected to be significant.

There are no projects of relevance to cumulative effects assessment on this VC.

Emissions

A recent air dispersion analysis was completed by SENES (2011) in support of an air permit renewal for the Whitehorse Diesel Plant. This analysis examined a range of load and unit capacity scenarios to predict air quality within the Whitehorse area. The air dispersion modeling indicated that, with the existing diesels, all air quality standards would be easily met outside the facility property boundary for all scenarios. The maximum predicted concentrations at the property boundary "maximum point of impingement" (Max POI)[3] were all less than 50% of the respective Yukon Air Quality Standard for all contaminants with the exception of particulate matter ($PM_{2.5}$). Very brief exceedances (a day or few days within a year) of the particulate matter standard were predicted at the Max POI for the worst case diesel generator operation scenarios, which assumed the maximum diesel that could be expected during an extreme drought.

Air emissions of the Project during operations will be dependent on the extent of future operations (energy to be generated) and will be addressed by the ongoing air emissions permitting processes. During the operations phase with the Project, when backup or peaking power is required at the Whitehorse Thermal Generating Station (WTGS), the new natural gas generators will emit air contaminants. However, it is important to keep in mind that the existing diesel engines at the WTGS, and all alternatives to the Project as reviewed in Chapter 6 (e.g., new diesel units) also generate air emissions when they are required to be run.

In summary, therefore, the impact of the Project on ambient air quality is the result of running the new natural gas engines in comparison to running new diesel engines. And for each alternative, operation will tend to reduce materially the use of other existing diesel capacity retained to meet grid capacity reliability planning requirements:

- After Project commissioning, when backup or peaking power is required, enhanced energy efficiencies and reduced fuel costs will result in the new gas engines being operated preferentially until additional capacity is required from the remaining diesel engines.

[3]The Maximum Point of Impingement (Max POI) is the location at which the highest concentrations of contaminants are expected to occur from Yukon Energy diesel engine emissions.

- Similarly, if the new diesel engine alternative to the gas-fired engines was to be selected, enhanced energy efficiencies will tend to result in these new diesel units also being operated preferentially until additional capacity is required from the remaining diesel engines.

The air emissions of the Project's gas-fired engines are compared to three different alternatives in Table 7-4. The rationale for each alternative is reviewed below.

For assessment of Project emissions during operation, Yukon Energy used a comparison of the performance characteristics of the proposed gas generating units (GE Jenbacher JMC624) provided by the manufacturer, with equivalent data from manufacturers of new diesel generation equipment, focused particularly on the CAT 3616, a unit of approximately similar size (4.4 MW continuous rating) from a manufacturer that provides similar unit performance data (i.e., a "not to exceed" standard for maximum expected unit emissions performance). As a cross-check, Yukon Energy also completed a comparison of diesel versus gas unit performance on the most likely alternative to the selected GE gas units (the Wartsila 6.7 MW 16V34DF). The Wartsila comparison is based on comparing the emissions criteria of a 6.7 MW dual fuel (not bi-fuel) unit in diesel operating mode versus in gas operating mode.

- The Wartsila unit data is not directly compared to the GE units selected for the Project as the specifications are not equivalent for two reasons: (1) the Wartsila units are of a much larger size than the GE gas units (6.7 MW versus 4.4 MW) and (2) Wartsila produces emissions information based on expected "indicative" performance while GE and CAT manufacturers produce emissions information based on a firm "not to exceed" standard.

- It is not possible to directly compare what are "indicative" values (Wartsila) against what are effectively "not to exceed" values (GE and CAT). For this reason GE gas values are compared against CAT diesel values, while as a cross-check Wartsila gas values are compared against Wartsila diesel values to show the relative performance of gas versus diesel.

The GE gas units are also compared to the existing units for reference; however, this comparison is not reflective of future options, as the existing units cannot be retained in service indefinitely, as reviewed in Chapter 5 and Chapter 6 (i.e., WD1 and WD2 replacement is required by no later than the end of 2015).

Application for an Energy Project Certificate and An Energy Operation Certificate Regarding The Proposed Whitehorse Diesel-Natural Gas Conversion Project
Yukon Energy Corporation CW-YEC-1-1(i) Attachment 1
February 27, 2014
Page 3 of 6

Table 7-4:
Project Air Emissions (GE 4.375 MW) as Compared to Alternatives

Generation Option		Unit	Air Emissions					
			CO	NOx	SO_2	PM10	PM2.5	VOC
Project compared to Alternatives								
New LNG	GE 4.375 MW	[kg/MWh]	4.06	1.85	0.003	0.04	0.02	0.91
New Diesel	CAT 4.4 MW	[kg/MWh]	0.66	11.40	n/a	0.15	n/a	0.85
Change LNG to new diesel		%	516%	-84%		-75%		7%
Alternative Reference Point - Wartsila Natural Gas Generation versus Diesel								
New LNG	Wartsila 6.7 MW	[kg/MWh]	2.27	2.54	n/a	0.07	n/a	0.81
New Diesel	Wartsila 6.7 MW	[kg/MWh]	1.03	14.41	n/a	0.16	n/a	0.50
Change LNG to new diesel		%	120%	-82%		-55%		63%
Project Compared to Existing Generation								
New LNG	GE 4.375 MW	[kg/MWh]	4.06	1.85	0.003	0.04	0.02	0.91
Existing Diesel (weighted average)		[kg/MWh]	0.59	8.14	0.013	0.16	0.12	n/a
Change LNG to existing diesel		%	586%	-77%	-79%	-78%	-85%	

With respect to the major air emissions criteria noted in the Watson Lake YESAB review of LNG generation, Yukon Energy notes the following with respect to the proposed Project based on the analysis provided in Table 7-4:

- **Nitrogen Oxide (NO_x), Particulate Matter (PM), Sulfur Dioxide (SO_2):** The YESAB conclusions out of the Watson Lake LNG Bi-Fuel project note that with gas generation, NO_x, PM and SO_2 are expected to decline. This is consistent with Yukon Energy's expectation for the Whitehorse Project, as set out in Table 7-4. While not all manufacturers routinely supply SO_2 emissions, the new gas engines are expected to outperform diesel in general, and GE gas values show a 79% reduction per kW.h as compared to the existing fleet of diesels. In addition, manufacturers are able to provide particulate (PM_{10}) values, but do not generally supply specific $PM_{2.5}$ values. Wartsila was able to indicate that approximately $PM_{2.5}$ would not be expected to exceed 50% of the PM_{10} value. The relative relationships (a decline with the introduction of gas generation) are expected to be similar between PM_{10} and $PM_{2.5}$. No further assessment is completed on these emissions variables given there is no adverse impact from the Project.
- **Carbon Monoxide (CO):** One characteristic of natural gas generation as compared to diesel is a potential increase in CO emissions. The Watson Lake LNG Bi Fuel YESAB Report noted that despite an increase in CO emissions in Watson Lake, the overall contribution of the power generation sector to CO levels in Watson Lake, and the level of CO in Watson Lake, remain well below Yukon standards. The same conclusion exists in Whitehorse. SENES (2011) prepared a summary of air quality monitoring data for Whitehorse indicating that the background average air quality, using the conservative 98th percentile level, was less than 15% of the Yukon Standard[4]. When the background conditions were modeled with the maximum Yukon Energy generation applied (drought conditions), at the absolute maximum point of impingement (the fence around the Yukon Energy property), the air quality index increased to less than 19% of the Yukon standard, or an increase of 4% of the standard[5]. Even applying a 600% increase (6 times multiplier, per Table 7-4) to the Yukon Energy impact due to usage of natural gas generation, measured using the highest generation scenario from 2011 (drought) at the maximum point of impingement, on top of the 98th percentile background conditions, the CO values remain well below 50% of the applicable standard. For this reason, the magnitude of impacts on CO emissions are expected to be small, occurring over the operating life of the Project (long-term) and occurring at the Project Study Area scale, and are not significant.
- **Volatile Organic Compounds (VOC):** Emissions of VOCs from stationary utility generation engines are very low. As set out in the SENES Air Quality Assessment conducted in 2008 (see Appendix 5D), the average emissions from stationary diesel engines equal approximately 0.4 grams per MW.h, or approximately 1760 grams/hour for operating diesel units relevant to the Project scale (4.4 MW). This is less than the hourly VOC emissions from one snow machine (2148 grams/hour) or less than seven snowblowers (at 275 grams/hour). Based on manufacturers ratings, VOC emissions from natural gas utility generation will be higher than for diesel units,

[4] See Appendix 5C for the 2011 Yukon Energy YESAB Proposal, SENES(2011) is included in Appendix A to that submission; background air quality at 858 µg/m^3, compared to a total standard of 5800 µg/m^3 using an 8-hour standard per page 35.
[5] 1,086.7 µg/m^3 per SENES (2011) page 42.

projected at 7% increase comparing GE units to CAT. The comparative values for the Wartsila comparators is an increase of 63%.

The Watson Lake YESAB review noted a concern with respect to increases in VOC emissions. This concern was based on two factors: (1) the emissions of VOCs with respect to a bi-fuel engine (as proposed for Watson Lake) were expected to increase 7.5 times as high as with diesel, and potentially up to 2000-6000 times as high, and (2) the emissions would include notable quantities of problematic substances such as benzene, which is a carcinogen. The situation with respect to the proposed Whitehorse Project is not equivalent to the Watson Lake situation. First, the increases in VOCs expected in the Whitehorse generation are well below the scale expected at Watson Lake (7% higher than with new diesel, versus 7.5 times as high) and second the combustion in Whitehorse units will be entirely natural gas from LNG sources, not a mixture of LNG and diesel fuel as is the case in Watson Lake. Natural gas that has been through the liquefaction process has had effectively all trace contaminants, such as benzene, removed as part of the liquefaction process as benzene freezes at temperatures well above the cryogenic requirements of LNG. Any benzene in the source natural gas will have been frozen out and collected at the liquefaction stage. If this were not done the benzene would become problematic for such matters as valve operation in the LNG transportation stage. Similar effects occur on all VOC contaminants which freeze at higher temperatures than the target cryogenic temperatures.

For this reason, the magnitude of impacts on VOC emissions are small, occurring over the operating life of the Project (long-term) and occurring at the Project Study Area scale, and are not significant.

In summary, the Project's use of natural gas rather than diesel (as well as the use of new and more efficient engines compared to existing diesel units) is expected to have the following emissions effects:

- Notable positive effects by reducing air emissions related to NOx, PM, and SO_2 (particulate emissions of existing diesel units were noted in the SENES 2011 dispersion analysis as the only emission from the WTGS to exceed 50% of Yukon Ambient Air Quality Standards (YAAQS) at the Max POI); and,
- Small adverse effects by increasing air emissions related to CO and VOC which, in each instance, are small in magnitude and occurring at the Project Study Area scale, and are accordingly assessed to not be significant (for the reasons set out above).

Chapter 5 (Section 5.4.2) identifies in Table 5-16 existing projects[6] and activities considered in the Cumulative Effects Assessment (CEA) and in Table 5-17, future projects[7] and activities considered in the CEA (i.e., projects for which project proposals to YESAB have been submitted and that are currently undergoing YESAB assessment). Effects of these projects on air quality relate primarily to dust and vehicle emissions. An air emissions permit related to emission of criteria air contaminants (such as CO or

[6] Annie Lake Trucking Ltd Gravel Quarry (YESAB Registry number 2011-0129) and the Concrete Batch plant on McLean Lake Road (YESAB Registry number 2010-0228).

[7] Lot 1247 McLean Lake Road (YESAB Registry number 2013-0018), the Yellow Truck Excavating Gravel Quarry (YESAB Registry number 2013-0015) and the Whitehorse Copper Tailings Reprocessing and Reclamation project (YESAB Registry number 2011-0064).

VOCs) has not been identified as a requirement for any of these projects. Given the short-term and small magnitude of Project effects related to dust and vehicle emissions and location of other projects a distance away along the Copper Haul Road, no cumulative adverse effects are expected.

The Project is expected to result in reductions in greenhouse gas (GHG) emissions, and as a result these emissions have not been assessed further[8].

Noise

With respect to noise, the nearest residence to the Project Construction Footprint is located approximately 500 m away, across the Yukon River in Riverdale. Baseline ambient noise levels were measured over a 5-day period in October 2012 at a monitoring location in close proximity to the nearest residence to the Project Construction Footprint, during a period when the existing Yukon Energy diesel generators were not running. Background noises were dominated by local traffic, the Yukon River, wind, dog and bird noises. Airplane traffic originating from the Erik Nielsen Whitehorse International Airport (Whitehorse airport) was a significant source of transient noise, typically lasting less than 5 minutes. The average daytime and nighttime noise measurements are indicative of a quiet residential neighbourhood.

During construction there will be increased noise produced by the Project on a somewhat continual daytime basis from the use of equipment on site that will include a loader, packer, dozer, excavator and trucks for earthworks; similar equipment for underground work and for surface finishes. Construction noise mitigation to minimize adverse effects will include compliance with applicable municipal requirements for construction hours and ensuring that all equipment maintains an operational muffler. The residual noise emissions for these activities are transient (i.e. these types of noise emissions no longer exist once construction equipment is no longer in use) and will be of similar character to existing traffic noise on Robert Service Way (low rating for magnitude). Additionally, the duration of these noise emissions will be limited to the period of construction (short duration) and the impact of the noise is not expected to be evident outside the Project Study Area. As a result, construction noise impacts are not expected to be significant.

During operations there will be noise generated by the Project as a result of operating the new natural gas engines. However, it is important to keep in mind that all Project alternatives considered in Chapter 6 (e.g., new diesel) also generate noise emissions when they are required to be run. As noted in Section 2, the current Project involves decommissioning of two existing diesel engines and replacing these engines with up to three new natural gas engines. After Project commissioning, when backup or peaking power is required, the new gas engines will be operated preferentially until additional capacity is required from the remaining diesel engines. The new natural gas engines will be located nearly twice as far from the nearest residential area as the existing diesel plant, and in closer proximity to commercially and public service zoned lands that are presently largely undeveloped under the approach path to the Whitehorse airport, where noise sensitive activities do not exist and are not expected to exist.

In addition, new natural gas engines will result in lower noise emissions than the existing diesel engines and lower than new replacement diesel engines.

[8] Emissions from diesel generation from the National Inventory Report (Environment Canada) average approximately 697.5 tonnes of CO2e per GW.h, while natural gas emissions from combustion equal approximately 451 tonnes of CO2e per GW.h.

with no determined use in a generally undeveloped and natural state until such time as planning has occurred to determine appropriate zoning.". While another Ta'an Kwäch'än Council Settlement Parcel has been given a specific zoning (e.g., C-23B zoned as RC2x), parcel C-28B has not been zoned Commercial Service within the zoning bylaw.

Yukon Energy understands that the Zoning Bylaw may be amended at some point in the future to reflect the Commercial – Service (CS) designation identified in Map 2 of the 2010 City of Whitehorse Official Community Plan. The Zoning Bylaw indicates that the purpose of this zoning designation is to, "…provide a district for a mix of land extensive business and commercial uses, including those that are vehicle oriented." There are thirty-two potential principal uses that range widely from animal clinics to custom indoor manufacturing to gas bars to emergency and protective services.

While Yukon Energy cannot begin to contemplate all the varied potential uses indicated by this broad commercial zoning category, none of the principal, secondary or conditional uses would indicate an adverse sensitivity to being diagonally located across a major thoroughfare such as Robert Service Way from the proposed LNG facility any more than they would be affected by existing generation facilities or the potential development of a City of Whitehorse services building on a property zoned Public Service adjacent to the Ta'an Kwäch'än Council Settlement Parcel in question.

Item R16: Emissions Estimates – Fugitive NG Releases Within Conveyance Circuit

Provide an estimate of methane emissions associated with fugitive leaks from valves and other equipment after the LNG has been vapourized and before it is combusted in the engines.

Response

Fugitive fuel leaks and the associated methane component emissions are, by design, expected to be negligible.

Item R17: Emissions Estimates – Greenhouse Gases

Describe the GHG emissions associated with combustion of diesel fuel in the existing engines, new diesel engines, and natural gas in the proposed engines.

Response

The greenhouse gas emissions associated with combustion of hydrocarbon fuels varies by fuel type. Table 7-4 of the Project Proposal presents a summary of the expected "not to exceed" emissions for the new natural gas fired engines and alternatives (i.e., new and existing diesel engines). Since the Project Proposal was submitted, and based on the life-cycle inventory the Pembina Institute completed, YEC was able to refine its estimate of GHG emissions for natural gas and diesel combustion (see Table A-1 Attached). It should be noted that when information was not available, emission factors for a given

constituent were taken from the U.S. National Renewable Energy Laboratory Life Cycle Inventory) Database (NREL LCI Database). This approach is similar to the approach taken by the Pembina Institute as part of life cycle emissions inventory (2013). Global warming potential multipliers for 20-year and 100-year time frame were obtained from the IPCC 5th assessment report (2013[1]).

Item R18: Emissions Estimates – Greenhouse Gases: Constituent Emission Factors

Describe the total mass emissions for CO_2, CH_4, and N_2O as well as CO_2-equivalent.

Response

Total mass emissions for CO2, CH4, and N2O as well as CO2-equivalent are presented in Table A-1 (attached) for new natural gas engines, new diesel engines and existing diesel engines.

Item R19: Emissions Estimates – Other Anticipated Greenhouse Gases

Describe any other GHG emissions associated with the Project (e.g., SF6 leaks from new transformers).

Response

No other significant sources of GHG emissions are expected with the operation of the project. SF6 releases from new electrical equipment are anticipated to be negligible (i.e., <1kg per year) based on experience with similar equipment currently in service.

Closing

Please do not hesitate to contact me at (867) 393-5350 or by email: travis.ritchie@yec.yk.ca should you have any questions, comments, or concerns regarding these responses.

Sincerely,

Travis Ritchie, P.Biol., EP
Manager – Environment, Assessment, & Licencing

[1] http://www.ipcc.ch/

Table A-1. Updated Project Air Emissions (GE 4.375MW) as Compared to Alternatives (New and Existing Diesel Engines)

Generation Option		Unit	Air Emissions										
			CO	NOx	SO_2	PM10	PM2.5	VOC	CO_2	CH_4	N_2O	GHG CO_2 Eq (20-yr)	GHG CO_2 Eq (100-yr)
Project compared to Alternatives													
New LNG	GE 4.375 MW	[kg/MWh]	4.06	1.8477	0.003	0.04	0.02	0.91	432.11	*1.07E-02*	*1.07E-02*	435.92	435.68
		[kg/h]	17.78	8.08	0.01	0.16	0.08	3.96	1,890.50	0.05	0.05	1,907.14	1,906.10
New Diesel	CAT 4.4 MW	[kg/MWh]	0.66	11.40	n/a	0.15	n/a	0.85	*978.97*	*2.19E-03*	*4.75E-03*	980.43	980.46
		[kg/h]	2.90	50.16	n/a	0.66	n/a	3.74	4,307.47	0.01	0.02	4,313.90	4,314.02
Project Compared to Existing Generation													
New LNG	GE 4.375 MW	[kg/MWh]	4.06	1.85	0.003	0.04	0.02	0.91	432.11	*1.07E-02*	*1.07E-02*	435.92	435.68
		[kg/h]	17.78	8.08	0.01	0.16	0.08	3.96	1,890.50	0.05	0.05	1,907.14	1,906.10
Existing Diesel (weighted average)		[kg/MWh]	0.59	8.14	0.013	0.16	0.12	*0.009*	465.25	*2.19E-03*	*4.75E-03*	466.72	466.74
		[kg/h]	1.86	25.58	0.04	0.52	0.38	0.03	1,462.23	0.01	0.01	1,466.82	1,466.91

Notes for Table A-1:

Global Waming Potential from IPCC 5th Assessment Report (2013)

Methane GWP (100-yr)	34 multiplier
Nitrous Oxide GWP (100-yr)	298 multiplier
Methane GWP (20-yr)	86 multiplier
Nitrous Oxide GWP (20-yr)	268 multiplier

Italic - indicates emission factor obtained from NREL LCI Database

CAT 4.4 MW Model 3616

CO_2 emissions for existing diesel engines are derived from stack testing results and are lower than expected for a diesel engine due to results from the Mirrlees and CAT engines, e.g., stack testing for Mirrlees (WD1, WD2 and WD3) ranged from 297.00 to 399.83 kg MWH CO_2 and the CAT (WD7) was 395.50 kg/MWH CO_2, while the EMD (WD4, WD5 and WD6) ranged from 614.04 to 722.04 kg/MWH CO_2.

The weighted average for Existing Diesel in Table A-1 is based on total capacity and assumes the Mirrlees engines, the EMDs and the Cat engines are all operated for the same amount of hours in a year. However, under current operation, the majority of the thermal generation is actually provided by the EMD and CAT engines. Were the weighted average calculation to assume actual usage, CO_2 emissions would be higher than reported in Table A-1. As such, CO_2 emissions for Existing Diesel included in Table A-1 are likely understated.

TOPIC: Odorant

REFERENCE:

PREAMBLE:

The City sees no indication of whether the fuel stock will be odorized. The City requires an understanding of whether the LNG, or vaporized natural gas will be odorized prior to use.

QUESTION:

a) Please fully explain whether LNG is odorized or not. If not, please fully explain why not.

b) Please fully explain whether the vaporized LNG will be odorized or not. If not, please fully explain why not and how leaks would be detected.

c) Please fully explain the potential impact of odorant on the citizens of Whitehorse. In the response, please fully discuss the transportation, storage, disposal and use of odorant, as well as the impacts of odorant leaks or spills.

ANSWER:

(a)

LNG is a liquid and cannot be odorized. Please see response to UCG-YEC-1-8(a).

(b)

The vapourized LNG that is piped as gas to the Whitehorse diesel plant will be odorized due to the length of the gas piping underground and in the diesel plant.

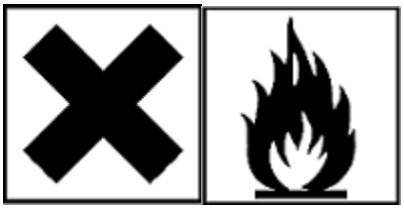
The vapourized LNG to the natural gas engines will not be odorized due to the very short piping runs and the presence of natural gas detectors throughout the LNG facility and natural gas engine areas.

(c)

The odorant that will be used is called mercaptan. It is used as it can be detected (smelled) by people at very small concentration levels. The mercaptan will be delivered by a “wick” injection system which utilizes the pressure drop across a hand valve in the main line to extract mercaptan from a drum storing the liquid.

Details regarding the transportation, storage, and disposal requirements can be found in the MSDS provided as Attachment 1 to this response.

Material Safety Data Sheet



SECTION 1 PRODUCT AND COMPANY IDENTIFICATION

SCENTINEL® S-20 Gas Odorant

Product Use: Odorant
Product Number(s): 0001024721, 0001024719, 0001024714, 0001024720, 0001024716, 0001024713, 0001024717, 0001024718, 0001033064, 0001024715, 0001024722
Synonyms: Gas Odorant; Mercaptan Mixture; Mixture of t-butyl mercaptan and methy ethyl sulfide; Mixture of t-butyl mercaptan and methy ethyl sulfide
Product CAS No.: Mixture

Company Identification:
Chevron Phillips Chemical Company LP
Specialty Chemicals
10001 Six Pines Drive
The WoodlandsTX 77380

Chevron Phillips Chemicals International N.V.
Brusselsesteenweg 355
B-3090 Overijse
Belgium

Product Information:
MSDS Requests: (800) 852 - 5530
Technical Information: (832) 813 - 4862
Responsible Party: Product Safety Group
Email:msds@cpchem.com

24-Hour Emergency Telephone Numbers
HEALTH:Chevron Phillips Emergency Information Center 866.442.9628 (North America) and 1.832.813.4984 (International)
TRANSPORTATION: North America: CHEMTREC 800.424.9300 or 703.527.3887
ASIA: +1.703.527.3887
EUROPE: BIG .32.14.584545 (phone) or .32.14.583516 (telefax)
SOUTH AMERICA SOS-Cotec Inside Brazil: 0800.111.767
Outside Brazil: 55.19.3467.1600

SECTION 2 HAZARDS IDENTIFICATION

****

EMERGENCY OVERVIEW
Clear liquid, repulsive odor.
NFPA RATINGS: **Health:** 2 **Flammability:** 3 **Reactivity:** 0

Signal Word:
Danger

Risk Phrases:
R51: Toxic to aquatic organisms.
R43: May cause sensitization by skin contact.
R11: Highly flammable.
R36: Irritating to eyes.
R65: Harmful: may cause lung damage if swallowed.

Safety Phrases:
S9: Keep container in a well-ventilated place.
S51: Use only in well-ventilated areas.
S62: If swallowed do not induce vomiting: seek medical advice immediately and show this container or label.
S16: Keep away from sources of ignition - No smoking.
S36/37: Wear suitable protective clothing and gloves.
S24/25: Avoid contact with skin and eyes.
S26: In case of contact with eyes, rinse immediately with plenty of water and seek medical advice.

****

IMMEDIATE HEALTH EFFECTS:
Eye: Contact with the eyes causes irritation. Symptoms may include pain, tearing, reddening, swelling and impaired vision. Not expected to cause prolonged or significant eye irritation.
Skin: Contact with the skin may cause an allergic skin reaction. Symptoms may include pain, itching, discoloration, swelling, and blistering. Not expected to be harmful to internal organs if absorbed through the skin.
Ingestion: This material can directly enter the lungs, if swallowed, or if subsequently vomited. Once in the lungs it is very difficult to remove and can cause severe injury or death.
Inhalation: This material has a strong objectionable odor that may cause nausea, dizziness, or headache.

SECTION 3 COMPOSITION/ INFORMATION ON INGREDIENTS

COMPONENT	CAS NUMBER	AMOUNT	EINECS / ELINCS	SYM	R-PHRASES
Tertiary Butyl Mercaptan	75-66-1	78.5 % weight	200-890-2	F Xn	R65, R43, R51, R11
Methyl Ethyl Sulfide	624-89-5	21.5 % weight	210-868-4	F	R11

Occupational Exposure Limits:

Component	Limit	TWA	STEL	Ceiling / Peak	Notation
Tertiary Butyl Mercaptan	ACGIH	Not Established	NA	NA	n-Butyl Mercaptan: 0.5 ppm
Tertiary Butyl Mercaptan	CPCHEM	.5 ppm	NA	NA	As n-Butyl Mercaptan

SECTION 4 FIRST AID MEASURES

Eye: Flush eyes with running water immediately while holding the eyelids open. Remove contact lenses, if worn, after initial flushing, and continue flushing for at least 15 minutes. Get immediate medical attention.
Skin: To remove the material from skin, use soap and water. Discard contaminated clothing and shoes

or thoroughly clean before reuse. Get medical attention if any symptoms develop.
Ingestion: If swallowed, do not induce vomiting. Give the person a glass of water or milk to drink and get immediate medical attention. Never give anything by mouth to an unconscious person.
Inhalation: Move the exposed person to fresh air. If not breathing, give artificial respiration. If breathing is difficult, give oxygen. Get medical attention if breathing difficulties continue.

Note to Physicians: Ingestion of this product or subsequent vomiting may result in aspiration of light hydrocarbon liquid, which may cause pneumonitis.

SECTION 5 FIRE FIGHTING MEASURES

See Section 7 for proper handling and storage.
FIRE CLASSIFICATION:
OSHA Classification (29 CFR 1910.1200): Flammable liquid.
NFPA RATINGS: **Health:** 2 **Flammability:** 3 **Reactivity:** 0
FLAMMABLE PROPERTIES:
Flashpoint: < -18°C (<-0.4°F) Estimated
Autoignition: NDA
Flammability (Explosive) Limits (% by volume in air): **Lower:** NDA **Upper:** NDA

EXTINGUISHING MEDIA: Use water fog, foam, dry chemical or carbon dioxide (CO2) to extinguish flames.

PROTECTION OF FIRE FIGHTERS:
Fire Fighting Instructions: For fires involving this material, do not enter any enclosed or confined fire space without proper protective equipment, including self-contained breathing apparatus.
Combustion Products: Highly dependent on combustion conditions. A complex mixture of airborne solids, liquids, and gases including carbon monoxide, carbon dioxide, and unidentified organic compounds will be evolved when this material undergoes combustion. Combustion may form: Sulfur Oxides, Carbon Oxides

SECTION 6 ACCIDENTAL RELEASE MEASURES

Protective Measures: Eliminate all sources of ignition in the vicinity of the spill or released vapor. If this material is released into the work area, evacuate the area immediately. Monitor area with combustible gas indicator. Wear appropriate personal protective equipment when cleaning up spills. Refer to Section 8.
Spill Management: Stop the source of the release if you can do it without risk. Contain release to prevent further contamination of soil, surface water or groundwater. Clean up spill as soon as possible, observing precautions in Exposure Controls/Personal Protection. Use appropriate techniques such as applying non-combustible sorbent materials or pumping. All equipment used when handling the product must be grounded. A vapor suppressing foam may be used to reduce vapors. Use clean non-sparking tools to collect absorbed material. Where feasible and appropriate, remove contaminated soil. Place contaminated materials in disposable containers and dispose of in a manner consistent with applicable regulations. Spill residues and contaminated soil may be deodorized using dilute (5%) aqueous solutions of bleach (sodium hypochlorite). Alternatively, household bleach (Clorox, Purex) in a dilute solution may be used. Do not use concentrated or dry bleach. Absorb in dry, inert material. Do not attempt to neutralize or deodorize bulk liquid mercaptan. Concentrated bleach will cause heating and possible ignition. Attempts to neutralize bulk liquid mercaptan with bleach solutions will be ineffective and only serve to increase the amount of liquid to dispose.
Reporting: U.S.A. regulations may require reporting spills of this material that could reach any surface waters. Report spills to local authorities and/or the National Response Center at (800) 424-8802 as appropriate or required.

SECTION 7 HANDLING AND STORAGE

READ AND OBSERVE ALL PRECAUTIONS ON PRODUCT LABEL . REFER TO PRODUCT LABEL OR MANUFACTURERS TECHNICAL BULLETINS FOR THE PROPER USE AND HANDLING OF THIS MATERIAL .

Precautionary Measures: This material presents a fire hazard. Liquid quickly evaporates and forms vapor (fumes) which can catch fire and burn with explosive violence. Invisible vapor spreads easily and can be set on fire by many sources such as pilot lights, welding equipment, and electrical motors and switches. Fire hazard is greater as liquid temperature rises above 15°F. Avoid breathing vapors or fumes which may be released during thermal processing.
General Handling Information: Avoid work practices that may release volatile components in the atmosphere. Local air pollution regulations should be consulted to determine if the release of volatile components is regulated or restricted in the area in which this material is used. Avoid contaminating soil or releasing this material into sewage and drainage systems and bodies of water.
Static Hazard: Electrostatic charge may accumulate and create a hazardous condition when handling this material. To minimize this hazard, bonding and grounding may be necessary but may not, by themselves, be sufficient. Review all operations, which have the potential of generating an accumulation of electrostatic charge and/or a flammable atmosphere (including tank and container filling, splash filling, tank cleaning, sampling, gauging, switch loading, filtering, mixing, agitation, and vacuum truck operations) and use appropriate mitigating procedures. For more information, refer to OSHA Standard 29 CFR 1910.106, 'Flammable and Combustible Liquids, National Fire Protection Association (NFPA 77), Recommended Practice on Static Electricity' (liquids, powders and dusts), and/or the American Petroleum Institute (API) Recommended Practice 2003, 'Protection Against Ignitions Arising Out of Static, Lightning, and Stray Currents' (liquids).
General Storage Information: Container is not designed to contain pressure. Do not use pressure to empty container or it may rupture with explosive force. Empty containers retain product residue (solid, liquid, and/or vapor) and can be dangerous. Do not pressurize, cut, weld, braze, solder, drill, grind, or expose such containers to heat, flame, sparks, static electricity, or other sources of ignition. They may explode and cause injury or death. Empty containers should be completely drained, properly closed, and promptly returned to a drum reconditioner, or disposed of properly. DO NOT USE OR STORE near heat, sparks or open flames. USE AND STORE ONLY IN WELL VENTILATED AREA. Keep container closed when not in use.
Container Warnings: Container is not designed to contain pressure. Do not use pressure to empty container or it may rupture with explosive force. Empty containers retain product residue (solid, liquid, and/or vapor) and can be dangerous. Do not pressurize, cut, weld, braze, solder, drill, grind, or expose such containers to heat, flame, sparks, static electricity, or other sources of ignition. They may explode and cause injury or death. Empty containers should be completely drained, properly closed, and promptly returned to a drum reconditioner or disposed of properly.

SECTION 8 EXPOSURE CONTROLS/PERSONAL PROTECTION

GENERAL CONSIDERATIONS:
Consider the potential hazards of this material (see Section 3), applicable exposure limits, job activities, and other substances in the work place when designing engineering controls and selecting personal protective equipment. If engineering controls or work practices are not adequate to prevent exposure to harmful levels of this material, the personal protective equipment listed below is recommended. The user should read and understand all instructions and limitations supplied with the equipment since protection is usually provided for a limited time or under certain circumstances.

ENGINEERING CONTROLS:
Use process enclosures, local exhaust ventilation, or other engineering controls to control airborne levels below the recommended exposure limits. Use in a well-ventilated area. If heated material generates vapor or fumes, use process enclosures, local exhaust ventilation, or other engineering controls to control exposure.

PERSONAL PROTECTIVE EQUIPMENT:
Eye/Face Protection: Wear eye protection such as safety glasses, chemical goggles, or faceshields if engineering controls or work practices are not adequate to prevent eye contact.
Skin Protection: Wear impervious protective clothing to prevent skin contact. Selection of protective clothing may include gloves, apron, boots, and complete facial protection depending on operations conducted. Users should determine acceptable performance characteristics of protective clothing. Consider physical requirements and other substances present when selecting protective clothing. Suggested materials for protective gloves include: 4H (PE/EVAL)
Respiratory Protection: If exposure is anticipated to be greater than applicable exposure limits, wear a NIOSH approved respirator that provides adequate protection from measured concentrations of this material, such as: Air-Purifying Respirator for Organic Vapors
Use a positive pressure, air-supplying respirator if there is potential for uncontrolled release, exposure levels are not known, or other circumstances where air-purifying respirators may not provide adequate protection. Air-purifying respirators are not recommended due to potential olfactory fatigue.

Occupational Exposure Limits:

Component	Limit	TWA	STEL	Ceiling / Peak	Notation
Tertiary Butyl Mercaptan	ACGIH	Not Established	NA	NA	n-Butyl Mercaptan: 0.5 ppm
Tertiary Butyl Mercaptan	CPCHEM	.5 ppm	NA	NA	As n-Butyl Mercaptan

SECTION 9 PHYSICAL AND CHEMICAL PROPERTIES

Appearance and Odor: Clear liquid, repulsive odor.
Autoignition: NDA
Boiling Point: 63°C (145.4°F) - 68°C (154.4°F)
Evaporation Rate: 1
Flammability (Explosive) Limits (% by volume in air): **Lower:** NDA **Upper:** NDA
Flashpoint: < -18°C (<-0.4°F) Estimated
Molecular Formula: Mixture
Molecular Weight: NA
Melting Point: NDA
Octanol / Water Partition Coefficient: log-Kow: NDA
pH: NA
Pour Point: NDA
Solubility (in water): Slight
Specific Gravity: 0.815 @ 16 şC (60°F)
Vapor Pressure: 5.7 psia @ 38 şC (100°F)
Vapor Density (AIR=1): >2
Viscosity: NDA
Percent Volatile: 100 % volume

SECTION 10 STABILITY AND REACTIVITY

Chemical Stability: This material is considered stable under normal ambient and anticipated storage and handling conditions of temperature and pressure.
Conditions to Avoid: No Data Available
Incompatibility With Other Materials: No data available
Hazardous Decomposition Products: Carbon Oxides. Sulfur Oxides.
Hazardous Polymerization: Hazardous polymerization will not occur.

SECTION 11 TOXICOLOGICAL INFORMATION

IMMEDIATE HEALTH EFFECTS:

Acute Oral Toxicity: Tertiary Butyl Mercaptan: LD50 / rat / 8.4 g/kg
Acute Dermal Toxicity: Tertiary Butyl Mercaptan: LD50 / rabbit / 20.8 g/kg
Acute Inhalation Toxicity: Tertiary Butyl Mercaptan: LC50 / rat / 26,432 ppm / 4 hour(s)

Eye Irritation: Tertiary Butyl Mercaptan:This material is irritating to the eyes.
Skin Irritation: Tertiary Butyl Mercaptan: This material is not expected to be irritating to the skin.
Sensitization: Dermal / sensitizer / guinea pig / based on test results for the components

ADDITIONAL TOXICOLOGY INFORMATION:
This product contains TERTIARY BUTYL MERCAPTAN:
Repeated Dose Toxicity: 13 weeks / Inhalation / rat / Doses 0, 9, 97 or 196ppm / 6 h/day, 5 days/week /LOAEL = 9ppm (proximal tubular nephrosis was observed in male rats only)
Reproductive and Developmental Toxicity: GD 6-16 / inhalation / mice / Doses: 0, 11, 99 or 195ppm (atmospheric concentration) / 6hr/day / NOAEL = 195ppm (no teratology effects were observed); GD 6-19 / inhalation / rat / Doses: 0, 11, 99 or 195ppm (atmospheric concentration) / 6hr/day / NOAEL = 9ppm (no teratology effects were observed)
Genetic Toxicity: Ames test - negative; Sister Chromatid Exchange Assay - negative; Mouse lymphoma forward mutational assay - positive; Mouse micronucleus assay - negative

SECTION 12 ECOLOGICAL INFORMATION

ECOTOXICITY:
This material is expected to be toxic to aquatic organisms.
Tertiary Butyl Mercaptan - 72 hour(s) / EC50 / green algae (*Selenastrum capricornutum*) / 13 mg/l
Tertiary Butyl Mercaptan - 96 hour(s) / LC50 / rainbow trout (*Salmo gairdneri*) / 34 mg/l
Tertiary Butyl Mercaptan - 48 hour(s) / EC50 / water flea (*Daphnia magna*) / 6.7 mg/l

ENVIRONMENTAL FATE:
The environmental fate of this material is not available.

SECTION 13 DISPOSAL CONSIDERATIONS

Use material for its intended purpose or recycle if possible. This material, if it must be discarded, may meet the criteria of a hazardous waste as defined by US EPA under RCRA (40 CFR 261) or other State and local regulations. Measurement of certain physical properties and analysis for regulated components may be necessary to make a correct determination. If this material is classified as a hazardous waste, federal law requires disposal at a licensed hazardous waste disposal facility.

SECTION 14 TRANSPORT INFORMATION

The shipping descriptions shown here are for bulk shipments only, and may not apply to shipments in non-bulk packages (see regulatory definition). Consult the appropriate domestic or international mode-specific and quantity- specific Dangerous Goods Regulations for additional shipping description requirements (e.g., technical name or names, etc.) Therefore, the information shown here, may not always agree with the bill of lading shipping description for the material. Flashpoints for the material may vary slightly between the MSDS and the bill of lading.

Shipping Descriptions per regulatory authority.

US DOT

UN3336, MERCAPTANS, LIQUID, FLAMMABLE, N.O.S., (tert-Butyl mercaptans, Methyl ethyl sulfide) , 3, II

ICAO / IATA

UN3336, MERCAPTANS, LIQUID, FLAMMABLE, N.O.S. , (tert-Butyl mercaptans, Methyl ethyl sulfide), 3, II

IMO / IMDG

UN3336, MERCAPTANS, LIQUID, FLAMMABLE, N.O.S., (tert-Butyl mercaptans, Methyl ethyl sulfide), 3, II , (<-18°C)

RID / ADR

UN3336, MERCAPTANS, LIQUID, FLAMMABLE, N.O.S., (tert-Butyl mercaptans, Methyl ethyl sulfide), 3, II, ADR

SECTION 15 REGULATORY INFORMATION

SARA 311/312 CATEGORIES:

1.	Immediate (Acute) Health Effects:	YES
2.	Delayed (Chronic) Health Effects:	NO
3.	Fire Hazard:	YES
4.	Sudden Release of Pressure Hazard:	NO
5.	Reactivity Hazard:	NO

REGULATORY LISTS SEARCHED:

01= CA Prop 65	17 = FDA 178	33 = RCRA Waste Appendix VIII
02 = LA RTK	18 = FDA 179	34 = RCRA Waste D-List
03 = MA RTK	19 = FDA 180	35 = RCRA Waste P-List
04 =MN Hazardous Substance	20 = FDA 181	36 = RCRA Waste U-List
05 =NJ RTK	21 = FDA 182	37 = SARA Section 302
06 = PA RTK	22 = FDA 184	38 = SARA Section 313
07 = CAA Section 112 HAPs	23 = FDA 186	39 = TSCA 12 (b)
08 = CWA Section 307	24 = FDA 189	40 = TSCA Section 4
09 = CWA Section 311	25 = IARC Group 1	41 = TSCA Section 5(a)
10 =DOT Marine Pollutant	26 = IARC Group 2A	42 = TSCA Section 8(a) CAIR
11 = FDA 172	27 = IARC Group 2B	43 = TSCA Section 8(a) PAIR
12 = FDA 173	28 = IARC Group 3	44 = TSCA Section 8(d)
13 = FDA 174	29 = IARC Group 4	45 = WHIMS - IDL
14 = FDA 175	30 = NTP Carcinogen	46 = Germany D TAL
15 = FDA 176	31 = OSHA Carcinogen	47 = Germany WKG
16 = FDA 177	32 = OSHA Highly Hazardous	48 = DEA List 1
		49 = DEA List 2

The following components of this material are found on the regulatory lists indicated.

Tertiary Butyl Mercaptan	3, 5, 6, 46
Methyl Ethyl Sulfide	46

WHMIS CLASSIFICATION:

Class B, Division 2: Flammable Liquids
Class D, Division 2, Subdivision B: Toxic Material
Skin Sensitization
Skin or Eye Irritation

CHEMICAL INVENTORY LISTINGS:

AUSTRALIA	YES (AUS)
CANADA	YES (DSL)
CHINA	YES (IECSC)
EUROPEAN UNION	YES (EINECS)
JAPAN	YES (ENCS)
KOREA	YES (ECL)
PHILIPPINES	YES (PICCS)
UNITED STATES	YES (TSCA)

EU LABELING:
Signal Word:
Danger

Symbols:
Xn - Harmful F - Flammable

Risk and Safety Phrases:
R51: Toxic to aquatic organisms.
R43: May cause sensitization by skin contact.
R11: Highly flammable.
R36: Irritating to eyes.
R65: Harmful: may cause lung damage if swallowed.
S9: Keep container in a well-ventilated place.
S51: Use only in well-ventilated areas.
S62: If swallowed do not induce vomiting: seek medical advice immediately and show this container or label.
S16: Keep away from sources of ignition - No smoking.
S36/37: Wear suitable protective clothing and gloves.
S24/25: Avoid contact with skin and eyes.
S26: In case of contact with eyes, rinse immediately with plenty of water and seek medical advice.

SECTION 16 OTHER INFORMATION

NFPA RATINGS: Health: 2 Flammability: 3 Reactivity: 0 Special: NA

(0-Least, 1-Slight, 2-Moderate, 3-High, 4-Extreme, PPE:- Personal Protection Equipment Index recommendation, *- Chronic Effect Indicator). These values are obtained using the guidelines or published evaluations prepared by the National Fire Protection Association (NFPA).

REVISION STATEMENT: This revision updates all sections of the MSDS please review.

ABBREVIATIONS THAT MAY HAVE BEEN USED IN THIS DOCUMENT:

TLV	-	Threshold Limit Value	TWA	-	Time Weighted Average
STEL	-	Short-term Exposure Limit	PEL	-	Permissible Exposure Limit
ACGIH	-	American Conference ofGovernment Industrial Hygienists	OSHA	-	Occupational Safety & Health Administration
NIOSH	-	National Institute for Occupational Safety & Health	NFPA	-	National Fire Protection Agency
WHMIS	-	Workplace Hazardous Materials Information System	IARC	-	Intl. Agency for Research on Cancer
EINECS	-	European Inventory ofexisting	RCRA	-	Resource Conservation Recovery Act

		Commercial Chemical Substances			
SARA	-	Superfund Amendments and Reauthorization Act.	TSCA	-	Toxic Substance Control Act
EC50	-	Effective Concentration	LC50	-	Lethal Concentration
LD50	-	Lethal Dose	CAS	-	Chemical Abstract Service
NDA	-	No Data Available	NA	-	Not Applicable
<=	-	Less Than or Equal To	>=	-	Greater Than or Equal To
CNS	-	Central Nervous System	MAK	-	Germany Maximum Concentration Values

This data sheet is prepared according to the latest adaptation of the EEC Guideline 67/548.
This data sheet is prepared according to the OSHA Hazard Communication Standard (29 CFR 1910.1200).
This data sheet is prepared according to the ANSI MSDS Standard (Z400.1).
This data sheet was prepared by EHS Product Stewardship Group, Chevron Phillips Chemical Company LP, 10001 Six Pines Drive, The Woodlands, TX 77380.

The above information is based on the data of which we are aware and is believed to be correct as of the date hereof. Since this information may be applied under conditions beyond our control and with which we may be unfamiliar and since data made available subsequent to the date hereof may suggest modifications of the information, we do not assume any responsibility for the results of its use. This information is furnished upon condition that the person receiving it shall make his own determination of the suitability of the material for his particular purpose.

TOPIC: **Duel fuel**

REFERENCE:

PREAMBLE:

The City notes that YEC has proposed a LNG only option, and does not appear to have considered a duel fuel alternative. If such an alternative were considered, if the price of LNG were to rise significantly above diesel fuel in the future, YEC could use the less expensive option. The City is aware that Yukon Electrical Company Limited (YECL) is considering an LNG facility, and to the City's knowledge, YECL is implementing a duel fuel option.

QUESTION:

a) Please fully explain if the technology for a duel fuel (LNG and Diesel) is available. If not, please fully explain, including all research and studies YEC has conducted to demonstrate that such an alternative does not exist.

b) Please fully discuss the potential for a duel fuel alternative, with costs and benefits of such an option.

ANSWER:

(a) and **(b)**

Please see response to YCS/LE-YEC-1-5 (a through c) and YCS/LE-38(h through j) for a review of the dual fuel options considered by YEC and comparison to natural gas or diesel only generation units.

TOPIC: **Stranded assets**

REFERENCE: **Application Appendix A, PDF page 57**

PREAMBLE:

In Appendix A, YEC provides a map of the existing facility and the new facility. In the diagram, it appears that the Unit WD1 and WD2 are in a larger facility. The City requires an understanding of what will be done with the space currently occupied by the existing units.

QUESTION:

a) Please fully explain what will be done with the space in the existing diesel plant that will be vacated when the existing diesel units are retired. Will the space be vacant, or will YEC use it for some other purpose?

b) If the space will be vacant, please fully explain the cost of maintaining vacant facilities.

ANSWER:

(a) and **(b)**

Decommissioning of the WD1 and WD2 units is planned to occur no sooner than the summer of 2015, after the gas-fired engine modules are in-service

This space will be available for potential future uses such as future dual fuel or gas-fired units, when these are required to meet capacity planning requirements. There are no anticipated additional costs for maintaining vacant facilities until they are required for other purposes.

TOPIC: **Storage Capacity**

REFERENCE: **Application, page 7, PDF page 11**

PREAMBLE:

In its Application, YEC indicates:

Yukon Energy has secured an LNG supply of up to 250 m3 per day for a minimum of five years from Shell Canada's Jumping Pound LNG plant being developed near Calgary and scheduled to start operation before the end of 2014. Yukon Energy also retains the potential during the term of the Shell Canada contract to source LNG from the Fort Nelson area in northern British Columbia should additional liquefaction facilities come into service in this area, and/or Shell Canada arranges to make LNG supplies available in this area.

The City requires information to assess the total storage capacity of the LNG facility, should the fuel supply be disrupted.

QUESTION:

a) Please provide the number of days the natural gas turbines will be able to operate at full capacity from storage, should the supply of LNG be disrupted for a period of time.

b) Please provide the last ten years history of road closures into Whitehorse.

c) Please provide an analysis that compares the daily delivery capability of LNG, the available storage capacity for LNG and the longest disruption of service through road closures over the last ten years to demonstrate that there is sufficient storage capacity to deal with any expected road closure.

ANSWER:

(a)

The three LNG storage tanks will have a capacity of 499.5 m^3. This will provide six days operation at full capacity with the two initial gas turbine engines, and four days operation at full capacity with the three gas turbine engines. Please see response to YUB-YEC-1-6(a) as regards potential to expand storage capacity in future at the site.

(b) and **(c)**

Please see response to YUB-YEC-1-5(f) for the information that is available regarding Alaska Highway road closures and consideration of contingency and risk issues related to LNG access and storage. The planned storage is considered to be prudent and sufficient, taking into account the expected use of the gas engines (i.e., sustained operation at full capacity for extended periods of days is not expected to be a normal activity), the information on expected road closure impacts, and the availability of ample diesel generation capacity on the grid as back up generation. As reviewed in response to YUB-YEC-1-6(a), the site can, in future, also accommodate additional storage when this is considered to be prudent to install.

TOPIC: **Potential Growth**

REFERENCE: **Application Page 8, PDF page 12**

PREAMBLE:

In the last paragraph of page 8, YEC indicates that an estimated cost of $4.4 million is provided for the third unit. The City notes that the third unit is to be installed for "a few years after the first two are in service". The City requires an understanding of the possibility for growth in the planned facility, should the first phase prove successful.

QUESTION:

a) Please provide the cost of each of the first two units.

b) Please fully explain how many units could ultimately be supported by the vaporization and storage facility, should the first project be successful, and there be a desire to expand the project. In the response, please provide the cost of expanding the storage and vaporization facility to meet growth if needed.

ANSWER:

(a)

The cost of each of the first two 4.375 MW GE units is approximately $3.9 million, not including costs for switchgear module, fluid transfer station, offloading and mechanical assembly in Whitehorse.

(b)

Please see YUB-YEC-1-6(a, c, and d) and YUB-YEC-1-10(b) regarding the extent to which additional generation units can be supported by the Project's LNG facilities, including the truck unloading, vapourization unit, storage tanks, and gas piping to the existing WTGS diesel plant. In general, many of the LNG facilities included in the Project can accommodate eventual full conversion in future of the WTGS plant to provide up to about 30 MW total generation using gas (either as gas-fired, or dual fuel [gas-diesel],

engines). As noted in these responses, the site can accommodate additional LNG storage - the timing and cost of adding tanks has not been assessed at this time.

TOPIC: **Transportation of Fuel**

REFERENCE: **Application, page 10, PDF page 14**

PREAMBLE:

In the last paragraph of page 10, YEC discusses the use of A-Trains and the fact that they have not been approved in Alberta or British Columbia. The City requires an understanding of the requirements for approval of A-Trains in Alberta and British Columbia, the time and process for approval, the likelihood of approval, and the cost if approval is not received.

QUESTION:

a) Please fully explain the process and requirements for approval of the use of A-Trains in Alberta and British Columbia. In the response, please outline all steps taken to date.

b) Please provide revised shipping and fuel cost estimates if approval of the use of A-Trains is not granted.

c) Please confirm that the use of A-Trains has been approved in the Yukon. If not confirmed, please fully explain, and provide the process and timelines for approval of A-Trains in the Yukon.

d) Please discuss what safety issues are presented by the use of A-Trains by YEC as contemplated in the Application. Include in the response a discussion of any plans YEC has in place or will have in place addressing safety issues presented by the use of A-Trains as contemplated in the Application.

ANSWER:

(a) and **(c)**

Please see response provided to YUB-YEC-1-5(i), which describes the regulatory process and timeframe to get A-Train approval for use in Yukon, Alberta and British Columbia. The A-Train preliminary design addressed the key issues relevant to Yukon regulators, including weight, width and length restrictions and vehicle dynamics and stability performance assessments, in order to grant specific approvals subject to specific commitments. YEC was advised in October 2013 that Yukon Highways and Public Works would accept the vehicle performance characteristics as applied for.

(b)

The Application notes (at Page 7) that currently available Tridem units with a 54,000 litre capacity may be used initially if there are delays in the licensing and/or fabrication of the new A-Train units. Please see YUB-YEC-1-44 for a further update regarding transportation cost estimates for A-Train and Tridem units.

(d)

Please see YUB-YEC-1-7(f), which reviews safety measures in place to address risks related to the WTGS diesel and proposed WTGS LNG fuel operations, including emergency response plans, spills management plans and training for on-site workers and for drivers transporting LNG. Please see also UCG-YEC-1-15(d) (safety record for LNG transport) and (g) (emergency preparedness plans).

TOPIC: **Anticipated Timeline**

REFERENCE: **Application page 11, PDF page 15**

PREAMBLE:

In the last paragraph of page 11, YEC indicates that it has ordered certain equipment that has long lead times. The City requires an understanding of the impact on rate payers if approval is not granted, and the equipment is not needed.

QUESTION:

a) Please provide copies of the purchase agreements, along with any termination options, or other buy out clauses that would be in force, should the equipment not be required. In the response, please clearly identify all costs that YEC would expect customers to pay.

ANSWER:

(a)

Purchase agreements are confidential commercial documents; as such, they cannot be released in this process. Each contract is based on YEC template documents, however, the final signed document will be amended as necessary resulting from negotiations with suppliers. Generally, in the event the owner terminates the agreement, YEC is legally bound to pay for work performed to the date of termination (or shortly thereafter).

Ratepayer costs will be determined by the Yukon Utilities Board based on costs that are considered prudent and reasonably incurred. This would be assessed at the time YEC applies to include such costs in its revenue requirement at a general rate application.

TOPIC: **Project Timeline**

REFERENCE: **Application page 12, PDF page 16**

PREAMBLE:

On page 12, YEC provides a series of steps for the proposed project. The City requires an understanding of the impact of project delays.

QUESTION:

a) Please fully discuss all contingencies included in the project timeline.

ANSWER:

(a)

Please see response provided to YUB-YEC-1(a) through (c), YUB-YEC-1-2 and YUB-YEC-1-3 which review the project schedule, contingencies and cost of delay.

TOPIC: **Hydro Generation**

REFERENCE: **Application, page 18, PDF page 22; Application, page 19, PDF page 23**

PREAMBLE:

On page 18 of its Application, YEC states "thermal generation is once again becoming the default option to meet current energy and capacity requirements on the Yukon grid until long-term loads are sufficient to support economic new renewable generation."

In the last paragraph on the page, YEC discusses near term hydro enhancements.

On page 19 of the Application, YEC provides forecast base case diesel generation requirements.

The City requires information to assess the options available to YEC.

QUESTION:

a) Please fully explain what long term loads would be sufficient to support new renewable generation. In the response, please fully explain the potential options that YEC envisions when it says "new renewable generation". In the response, please address the forecast Diesel Generation Requirements as outlined in Appendix C, indicating at what level new renewable generation would become feasible.

b) Please fully discuss the costs and lead times for each new renewable generation option.

c) In Table 4-1, YEC provides a forecast of diesel generation, increasing from 11 GW.h in 2013 to 92 GW.h in 2030. If there is no incremental renewable generation implemented, please fully explain how many LNG units would be required to satisfy the increased load.

d) Please fully discuss the status of the near term enhancements discussed on page 18.

ANSWER:

(a) and **(b)**

The information that YEC can provide at this time on renewable energy options is summarized in the Application.

The Application (at pages 18 and 19) summarizes changing grid load conditions and YEC's ongoing planning to address forecast future loads and default diesel generation requirements. Options noted include DSM (working with YECL), additional potential near-term hydro enhancements that YEC is examining (beyond the hydro enhancements recently brought into service at Mayo B and Aishihik), and other renewable wind and greenfield hydro options that YEC is pursuing for potential future development when long term loads can justify such developments.

Section 4.2.2 of the Application (pages 23 and 24) outlines that no feasible renewable resource alternatives to the Project have been identified within the relevant near-term time period, i.e., the next few years when reliable new capacity is required. This section also references Table 8-2 of *Overview of Yukon Energy's 2011 Resource Plan: 2011-2030 (the "Overview")* [which was filed in YEC's 2012/13 GRA proceeding in YECL-YEC-18(a), Attachment 1)[1]], which reviewed wind and biomass options in the context of much higher near-term loads than are provided in Appendix C of the Application - and even with these much higher loads, the 2011 Resource Plan concluded that none of the non-hydro renewable resource options (e.g., wind and biomass were both examined) could provide levelized costs of energy over their life competitive with diesel generation.

The Overview of the 2011 Resource Plan provides summary details (including costs) on each renewable option potentially able to be developed in a "short-term" time period of less than five years, as well a separate section (Section 7) that reviews similar information available on longer-term resource options to default diesel generation.

[1] In the YEC 2012/13 GRA proceeding, these matters were also addressed in detail in YCS-YEC-1-8 and YCS-YEC-2-10 (the latter included Table 8-2 from the Overview). Lead times for various wind (three years after adequate wind monitoring) and greenfield hydro options (seven or more years) were addressed in the Overview. To highlight the information from Table 8-2 as to loads needed for wind options to be cost competitive, the estimated LCOE for 21 MW wind was 40.0 c/kW.h assuming "Scenario A" from the 2011 Resource Plan (Victoria Gold load connected) with DSM/SSE; the estimated LCOE for this wind option dropped to only 21.3 c/kW.h if the Scenario A 2019 load (i.e., includes Victoria Gold and other mine loads as assumed) is extended to 2030.

Yukon's extensive available hydro sites are summarized - and the challenges in developing different sites are highlighted (including coordinating development of any specific option with specific relevant loads as regards magnitude, seasonality, location and timing requirements).

In summary, Yukon Energy's Overview as filed in the 2012/2013 GRA highlights the extent to which sustained (e.g. 20+ years) and higher grid loads are required before capital intensive renewable resource options (e.g., greenfield hydro or wind) would be cost competitive options for ratepayers. In addition, the analysis noted the extent to which thermal generation (diesel or gas) would likely continue to be required on the grid even when such options were developed. Yukon Energy is not able to provide any more specific guidance today on what longer-terms loads would be sufficient to support new renewable generation beyond the short term hydro enhancements noted (i.e., the Mayo Lake Enhanced Storage Project and Marsh Lake Storage Project, each of which [subject to successful environmental and socio-economic regulatory review] is likely feasible today at current grid loads).

Please also see YCS/LE-YEC-1-27 and YCS/LE-YEC-1-59.

(c)

YEC has not done any specific analysis to examine how many gas-fired units would be required to satisfy the forecast default diesel generation in the Base Case to 2030. The following are noted on this matter:

- Current planning assumes that new thermal generation will be added to the grid when required to prevent a capacity shortfall (as forecast in Table C-4 of Appendix C of the Application), after taking into account forecast peak grid load, retirements of existing diesel units, and new reliable (during winter peak) generation units added.

- Table C-4 indicates a forecast default diesel capacity shortfall of 63.6 MW by 2030, reflecting the extensive diesel retirements required by that time, the updated Base Case load growth forecast, and the exclusion of any forecast new capacity (including the 13.1 MW new gas-unit capacity in the Application).

- Assuming that approximately 30 MW of new gas-units were installed at the WTGS over this period (in response to the expected retirement of all existing units by 2026), the 2030 forecast shortfall at other locations would approximate 33.6 MW. Some of this is likely to be met by replacement of the 13 MW of diesel retirements forecast at Faro, Mayo and Dawson City (such units may well be diesel, and would be required for reliability throughout the grid). The options used to meet balance of the requirement would need to be assessed as required in the future.

- If 30 MW of gas-fired engine capacity was to be installed at the WTGS by 2030, the forecast default diesel of 92.5 GW.h in 2030 would be equal to an approximate 35% annual utilization of this gas-fired engine capacity. [Actual default diesel or gas-generation requirements, however, will be reduced in 2030 to the extent that any new renewable generation is developed by that time (as is likely to occur); further, the forecast default diesel reflect long-term average hydro generation, and added analysis would be needed to assess the extent to which 30 MW of gas-fired engine capacity could meet default diesel requirements during severe drought water conditions].

(d)

The Application at pages 18 and 24 (footnotes 28 and 29) identifies two near-term hydro enhancement projects: the Mayo Lake Enhanced Storage Project and Marsh Lake (Southern Lakes) Storage Project. Each of these projects is still at the environmental and regulatory planning assessment stage, prior to any filings with YESAB. The earliest feasible date for either project to come into service is likely 2016 - but timing will be determined by the regulatory review stage requirements.

TOPIC: **Retirement of Diesel Units**

REFERENCE: **Application Page 23, PDF page 27**

PREAMBLE:

On page 23, YEC indicates that the continued use of the existing WD1 and WD2 units in not advisable as it would expose the grid to unreliable generation. The City requires an understanding of the replacement times for the balance of the diesel fleet.

QUESTION:

a) Please provide a table that identifies all remaining diesel generation for Whitehorse. In the response, please provide the age of each unit, the anticipated end of life for each unit, and the cost to maintain each unit at an adequate level of reliability beyond its recommended end of life.

b) Please fully discuss YEC's plans for replacement of the remaining diesel fleet. Include in this discussion whether YEC's plans are to replace the remaining diesel fleet with diesel generation, with LNG, or something else.

ANSWER:

(a)

Please see Table 1 below.

Yukon Energy cannot provide the cost to maintain each remaining diesel unit at an adequate level of reliability beyond its recommended end of life. This request is beyond the scope of the current Application (which is focused only on retirement and replacement of WD1 and WD2).

Table 1:
Current YEC WTGS Inventory: In service & Planned Retirement Dates

Unit No.	Prime mover type	Name Plate Capacity	MCR rating (kW)	Gen. Rating (KVA)	Gen. Voltage (V)	In Service Date	Planned Retirement Date	Years in service as of 2014
WD1 (Mirrlees)	Diesel	3,920	3,500	4,250	6,900	1968	2014	46 yrs
WD2 (Mirrlees)	Diesel	5,150	4,500	6,000	6,900	1968	2015	46 yrs
WD3 (Mirrlees)	Diesel	5,150	4,500	6,000	6,900	1970	2021	44 yrs
WD4 (EMD)	Diesel	2,500	2,250	3,000	4,160	1975	2025	39 yrs
WD5 (EMD)	Diesel	2,500	2,250	3,000	4,160	1975	2025	39 yrs
WD6 (EMD)	Diesel	2,700	2,500	3,125	4,160	1990	2025	24 yrs
WD7 (Caterpillar)	Diesel	3,300	3,000	4,125	4,160	1991	2026	23 yrs

(b)

Yukon Energy assumes from the context provided that this question relates to plans for replacement of the remaining diesel fleet at Whitehorse only and has confined its response to the diesel fleet at Whitehorse.

It is assumed that backup capacity will continue to be required at Whitehorse, and subject to ongoing confirmation of ratepayer savings, future expansion of gas displacement of diesel fuel generation is expected to occur as required in response to grid capacity planning shortfalls resulting from load growth and/or diesel unit retirements.

The following are noted in this regard:

- Opportunities for blend fuel use with existing diesel units will be examined in the near term, i.e., such opportunities involve minimal capital costs (compared to new units) and provide added opportunity to use the LNG infrastructure now being established to displace diesel fuel prior to retirement dates for existing diesel units.

- When a new engine is required to meet capacity planning requirements the opportunity will be examined to place new natural gas or dual fuel generation units in the bays previously used by WD1 and WD2. Again, new engines using gas provide added opportunity to use the LNG infrastructure now being established to displace diesel fuel prior to retirement dates for existing diesel units.

- The existing WTGS was initially commissioned in 1968, and its five existing diesel engines that will remain after WD1 and WD2 are retired, are all planned to be retired within the next 13 years (see Page 22 and Appendix C of the Application). This will create ongoing opportunities for future replacement of existing diesel generation units to future natural gas or dual fuel generation units.

Replacement costs are expected to be similar for new diesel or gas-fired generation in the future due to the fact that the LNG infrastructure required to support gas-fired generation at the WTGS will already be in place as a result of the Project (subject to adding LNG storage tanks as may be required for gas-fired capacity beyond the initial 13.1 MW addressed in the current Project).

Please also see CW-YEC-1-6(b) and CW-YEC-1-10.

TOPIC: **Project Economics – Compared to New Diesel**

REFERENCE: **Application Section 4.2.4, Table 4-3, PDF 36**

PREAMBLE:

In Table 4-3, YEC provides a table of costs for new diesel and LNG. In Table 3-1, YEC provides a detailed breakdown of the costs of the LNG option.

QUESTION:

a) Please provide the detailed models in Excel format that were used to derive the analysis in Table 4-3. In the response, include the rate of return for the two options, the fuel price assumptions, asset life, and operation & maintenance cost assumptions.

b) Please provide a table, like Table 3-1, for the diesel option capital costs included in Table 4-3. In the response, please fully explain the differences in costs for each item in Table 3-1 comparing LNG to diesel.

c) The City is aware that Yukon Electrical Company Limited (YECL) is considering a LNG facility, and is considering leasing the facility. Please fully whether YEC has conducted any analysis comparing the cost of leasing to the cost of owning the facility. If not, please fully explain why not. If yes, please provide any business cases or assessments done by or on behalf of YEC comparing these options regarding LNG facilities.

d) Please provide the detailed working models in Excel format in support of the sensitivities provided in Tables 4-4 and 4-5.

ANSWER:

(a) and **(d)**

Please see UCG-YEC-1-2 Attachment 1 for the Excel version of the tables with detailed calculations and with formulae intact. Please note that the assumptions in Table 4-3 do not include impact of non-fuel O&M expenses.

(b)

Please see YECL-YEC-1-6(b). Please also see response to YUB-YEC-1-26(a) and (b).

(c)

YEC did not consider a leasing option for LNG project equipment or the overall facility, and cannot provide comparison of owning and leasing options. YEC is not aware of leasing financing options that would provide costs for ratepayers as low as can be provided by YEC financing and ownership; further, a lease of equipment would likely need to be treated as a capital lease on YEC's accounts.

TOPIC: **Load Scenarios**

REFERENCE: **Application Appendix C**

PREAMBLE:

YEC provides its load scenarios in PDF format. The City requires the information in Excel format to understand the calculations and assess the forecasts.

QUESTION:

a) Please provide the load scenarios in Excel format. In the response, please provide the analysis included in the application, and supporting working papers.

b) Please provide and fully explain YEC's assessment of the probability of each of the forecasts included in Table C-2 and C-3 actually occurring.

ANSWER:

(a)

Please see UCG-YEC-1-2 Attachment 1 for the Excel version of the load forecast tables. Load forecast assumptions are reviewed as part of Appendix C of the Application.

(b)

Yukon Energy does not assign probabilities to its load forecasts or its load forecast scenarios and therefore the probability of each scenario examined in Appendix C occurring cannot be provided. In looking at these scenarios, the following are noted:

- The Base Case with no Alexco is intended to be a conservative assessment of potential load requirements in the near term.

- The Base Case with Alexco would more closely reflect a "likely" scenario at this time based on Alexco's plans to resume operation by 2015.

- Scenario A with Carmacks Copper is intended to provide an assessment of the only potential near-term new mine connection scenario that YEC considered to merit review at the time the update was prepared.

The load forecasts included in Appendix C of the Application are based on the best information available at the time the Application was prepared. As noted in Appendix C, the load forecast is updated on an ongoing basis to reflect new information regarding the timing for connection or reopening of mines and for updates regarding non-industrial and existing mine loads. Further, as these are forecasts for specific scenarios, it is expected that the actual load will differ from the forecast provided in Appendix C.

Appendix C considered the impacts of four separate and credible load scenarios (developed based on most up to date information available at the time), however, the economic analysis included in the Application relied upon the most conservative load scenario examined in Appendix C (Base Case with no Alexco after fall 2013).

Donald Roberts
(DR)

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) Please provide a copy of the Yukon Development Corporation Act.

b) Please explain YEC's definition of sustainable development? How can YEC justify converting from one fossil fuel to another that will require major infrastructure when YEC has in place the infrastructure for diesel operations?

ANSWER:

(a)

The *Yukon Development Corporation Act* is a publically available document that can be relied upon by any party to this proceeding and is available on the Yukon Development Corporation or the Yukon Government website at the following links:

http://www.ydc.yk.ca/uploads/documents/yudeco.pdf

http://www.gov.yk.ca/legislation/acts/yudeco_c.pdf

(b)

Please see response provided to YCS-YEC-1-60(b) which reviews Yukon Energy's mandate for sustainable development. The Application reviews the need and justification for the Project, including the Project economics. Please see also YUB-YEC-1-13(a).

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) Please provide the report of the Public Meeting held at Mt. Mac on July 8, 2013. Please provide the Whitehorse Star article found at http://www.whitehorsestar.com/archive/news/2013/07/09, called Yukon Energy president staunchly defends LNG choice, about the YEC LNG Public Meeting. Could YEC please outline the extent of support that YEC gained from that meeting?

ANSWER:

(a)

Please see Attachment 1 of this response which provides a summary of comments received from the public at the July 8, 2013 public meeting.

Yukon Energy summarized the results of its public consultation process in Chapter 4 of the YESAB Project Proposal and Section 5 of the Application. With regard to the public meeting held at Mt Mac on July 8, 2013, the YESAB Project Proposal notes as follows:

> "On July 8, 2013 Yukon Energy hosted an open house for the general public in Whitehorse, including residents of the City and surrounding area. A presentation was provided to introduce the Project, and Yukon Energy staff and consultants were on hand to field questions and receive feedback from participants. This event was designed not only to provide the current understanding of the Project and its components, but to also hear the concerns and views of the public. The presentation by Yukon Energy on the Project status and comments received from the public are provided in Appendix 4E. Approximately 60 people (not including Yukon Energy and its consultants) attended the event."

As noted, the public consultation process is designed to provide the public with the Corporation's current understanding of the Project and its components, and to hear the concerns and views of the public. The key interests, concerns, and perspectives raised during the public involvement process were considered by Yukon Energy and incorporated in the Project design and effects assessment process, where applicable. The interests and perspectives raised by various stakeholders were balanced with other considerations, and met the duty set for by YESAB's Proponent's Guide to Information Requirements for Executive Committee Project Proposal Submissions (2005) to "consider fully and fairly any views presented."

Chapter 4, Section 4.5 of the YESAB Project Proposal reviews key issues and perspectives heard from stakeholders and the public regarding the Project. In summary, participants in public involvement activities provided a range of interests and perspectives. In sum, a large portion of comments received from the general public did not relate directly to the Project and how it is proposed to be carried out, but were focused more generally on interests and concerns with LNG as a supply option, oil and gas extraction (within Yukon and outside Yukon), hydraulic fracturing and life cycle analysis of LNG vs. diesel. Many comments were focused on advocating use of other renewable supply options such as wind, geothermal, solar and biomass as opposed to LNG.

The Whitehorse Star article referenced is a publically available document. Intervenors can rely on any publically available documents they so choose should they wish to put forward evidence of their own as part of this proceeding.

ATTACHMENT 4E-1.2
SUMMARY OF INTERESTS AND CONCERNS



Meeting Report

Title:	**Whitehorse Diesel-Natural Gas Conversion Project – Meeting with Yukon Chambers of Commerce and Whitehorse Chambers of Commerce**		
Attendees:	Yukon Chambers of Commerce Whitehorse Chambers of Commerce **Yukon Energy representatives** Piers McDonald, Chair, Yukon Energy Board of Directors David Morrison, President and CEO Hector Campbell, Director, Resource Planning Marc-Andre Lavigne, Resource Planner Travis Ritchie, Manager, Environment, Assessment and Licencing Janet Patterson, Manager, Communications		
Meeting Location:	Kwanlin Dün Cultural Centre		
Date:	July 4, 2013		
Author:	Janet Patterson	**Phone:**	(867) 393-5300
Meeting Purpose	To share information about the project to the community at large, including what work has been completed to date. To gain an understanding of community interests and concerns regarding this proposed project.		
Introduction	David Morrison welcomed everyone to the meeting and provided a brief overview of the Project to date. A PowerPoint presentation was shown to the group.		
Discussion	Questions were asked throughout the presentation and during the open house segment. Interests, concerns and questions voiced by participants were recorded and are outlined below.		



- Question: Will you buy the trucks transporting the LNG?
- Question: How does the natural gas stay in a liquid state?
- Question: Where do we source our diesel fuel today?
- Question: Is fracking OK?
- Question: Safety is the other big concern.
- Question: What renewables are you looking at?
- Question: What about job skills to transition to LNG?
- Question: Can the construction of the plant be done by local contractors?
- Question: We have propane suppliers. Could they transition to LNG?
- Comment: We should have a breakfast meeting where Yukon Energy could outline the possible local business opportunities.
- Question: What about Eagle Plaines?
- Question: Is there a concern about the shelf life in the storage tanks if we don't use it quickly?
- Question: What about the LNG in Watson Lake: it's a blend of LNG and diesel. Did you look at that?



Meeting Report

Title:	**Whitehorse Diesel-Natural Gas Conversion Project – Meeting with Yukon Conservation Society and Yukoners Concerned About Oil and Gas Exploration**		
Attendees:	Yukon Conservation Society Yukoners Concerned About Oil and Gas Exploration **Yukon Energy & consultants:** Piers McDonald, Yukon Energy David Morrison, Yukon Energy Hector Campbell, Yukon Energy Marc-Andre Lavigne, Yukon Energy Travis Ritchie, Yukon Energy Janet Patterson, Yukon Energy Mona Pollitt-Smith, InterGroup Don McCallum, Morrison-Hershfield Duncan Rotherham, ICF Marbek Aaron Schroeder, ICF Marbek Adam Goehner, Pembina Institute David Glessner, Braemar Engineering Dan Hrebenyk, Senes Consulting		
Meeting Location:	Mount McIntyre Recreational Centre		
Date:	July 8, 2013		
Author:	Janet Patterson	**Phone:**	(867) 393-5300
Meeting Purpose	To share information about the project as well as gain an understanding of community interests and concerns regarding this proposed project.		
Discussion	Questions were asked throughout the presentation and during the open house segment. Interests, concerns and questions voiced by participants were recorded and are outlined below.		



- Question: Why do you indicate that you'll be burning more natural gas in 2017? Is the base load going up?
- Question: We burned $1 million worth of diesel last year, so how can you explain how Yukoners could save $2.7 million in 2015?
- Question: Do you have a crystal ball as to how cold it will be and so how much fuel you'll need?
- Question: But we hear that the mines will be reducing their consumption.
- Question: At the charrette two years ago you were talking about needing new energy options for base load. Now you're talking about backup.
- Question: Is DSM accounted for in these numbers?
- Question: Where are you getting your numbers from? This is a huge amount of money.
- Question: Why weren't these numbers reflected in the 20-year resource plan?
- Question: Have you taken into account the sensitivity for a price spike with the coming of increased competition?
- Question: But eventually the price of natural gas will go up.
- Question: Why are you only talking about LNG versus diesel? Why not renewables?
- Question: So even if you were using wind you'd still need a backup?
- Question: Why not use biomass as backup?
- Question: Have you already ordered the engines?
- Comment: It's very upsetting that you would go ahead and order equipment even before getting the go-ahead for the project. You are a clown corporation.
- Question: Why not put the new engines in the diesel plant?
- Comment: This project has developed further along than I realized. This is a foregone conclusion. You just told your consultants what to say.
- Question: Who owns the land where the units would be placed?
- Question: Do you still see this as a transition or are you feeling that if this fossil fuel is better that it will satisfy your needs and you won't look any further.
- Question: So this system will be redundant at some point?
- Question: I am uncomfortable that now you are calling this backup, when in the 20-year resource plan it was baseline.
- Question: So if there is a mine come online will you drop another natural gas module on that property?
- Comment: This reminds me of schools, where they put in one modular unit and all of a sudden there are many modules.
- Question: Would you sell the gas retail?
- Question: But you're looking for customers, correct?
- Question: Space heating and transportation are huge users of energy. What's wrong with investing money in renewables so we can get into those markets?
- Question: What will trigger a true move to renewables? Political direction? Increased load?
- Comment from another audience member: It's us who will trigger this.



- Question: Have you calculated beyond peak oil, peak water, peak trees, peak people? I encourage you to look deeper.
- Question: Who is the ultimate policy driver?
- Comment: You are so narrowly focused. There is a short time frame in terms of when we have to act with regard to climate change. We are at a crossroads. This is the beginning of the end for us. It's a foot in the door for the natural gas industry. We need to replace space heating and transportation with renewables. It's low hanging fruit. Space heating is where you should be focused.
- Comment: You should turn off people's hot water during peak times so you don't have to turn on diesels. You need a smart grid and proper load management. You are back in the stone ages. LNG is just putting a band-aid on it.
- Comment: What about methane? I wish you had broken it out of the GHG emission numbers. Methane was excluded from your study.
- There was a technical discussion about the methodology of the studies.
- Question: Can we have another independent study done?



Meeting Report

Title:	**Whitehorse Diesel-Natural Gas Conversion Project – Public Open House**		
Attendees:	**Yukon Energy & consultants:** Piers McDonald, Yukon Energy David Morrison, Yukon Energy Hector Campbell, Yukon Energy Marc-Andre Lavigne, Yukon Energy Travis Ritchie, Yukon Energy Janet Patterson, Yukon Energy Mona Pollitt-Smith, Intergroup Consultants Don McCallum, Morrison-Hershfield Duncan Rotherham, ICF Marbek Aaron Schroeder, ICF Marbek Adam Goehner, Pembina Institute David Glessner, Braemar Engineering Dan Hrebenyk, Senes Consultants		
Meeting Location:	Mount McIntyre Recreational Centre		
Date:	July 8, 2013		
Author:	Janet Patterson	**Phone:**	(867) 393-5300
Meeting Purpose	To share information about the project as well as gain an understanding of community interests and concerns regarding this proposed project.		
Discussion	Questions were asked throughout the presentation and during the open house segment. Interests, concerns and questions voiced by participants were recorded and are outlined below.		

- Question: How is it that for LNG you need a whole new storage facility, a whole new site, new technology, and that is only going to cost you $4-million more than replacing diesels with diesels?
- Question: Why not put the units at the Minto mine interchange?
- Question: Can you provide a breakdown in the cost of diesel to diesel versus diesel to natural gas?
- Question: Why do you need to renovate the diesel plant?
- Question: Have you contacted anyone in Alaska bout what they are doing for their supply? Their plants come from Finland.
- Question: Why the rush?
- Comment: I worked in Inuvik and that plant doesn't have to be changed and it's around the same age.
- Question: In your 20-year Resource Plan you state that the cost of diesel is about $1.5 million per megawatt. Now you are saying it's $3 million per diesel. How could it have jumped that much in such a short time?
- Comment: You talk about monetary cost but that's not the most important thing. It's the environmental cost that's so important to take into account.
- Question: How much power goes to the mines?
- Question: So if the price for diesel has shot up, then that makes renewables look better, correct?
- Comment: But if you spend money on LNG then there is less money to go towards renewables.
- Comment: This is just an elaborate scheme to have natural gas sitting here.
- Comment: It's all based on the utilities supplying the mines. Why not get the mines off power so they aren't dependent on the grid.
- Question: What is the shelf life of LNG?
- Question: So if we have LNG, you'll be forced to use it or lose it, correct? End up burning more fossil fuel than you normally would if you had diesel, since diesel can sit in the tank without any issue.
- Comment: This is an old fashioned way of looking at things and not a very Yukon-based way. I think you have a responsibility to generate with a Yukon based fuel, like biomass.
- Question: Your LNG 5 year agreement doesn't cover the life of the natural gas unit, if you say the unit has a lifespan of 25 years.
- Question: Is LNG explosive?
- Comment to consultants: Your life cycle assessment was based on 100 years, but we don't have 100 years to do something about climate change.
    - There was a discussion that follows where members of the public said there were flaws in the study and said it was a greenwash. "We want to see a 20 year horizon."
- Comment: Put the $34 million into a net metering policy.
- Comment: Buy second hand diesels. You don't need all this fancy new equipment.

- Comment: The life cycle assessments should be reviewed by peers.
- Comment: This is a rush job. Why are you trying to do this in two weeks? You haven't convinced me you are ready to do this.
- Comment: Buy Minto's diesels and use them.
- Question: What happens with natural gas builds up in the tank?
- Question: How many trucks would there be on our highways?
- Question: Can our turbines not generate all the power we need?
- Question: Why not use wind and solar and keep hydro for backup?
- Comment: This is a meeting that should have happened earlier. People needed this information before this decision was made. A lot of people here are looking for a different way forward. We're talking about people's futures here. LNG has caused suffering all around the world. We should have a referendum. How many people in this room want LNG? (3 hands were raised).
- Comment: I'm appalled that you are adopting another fossil fuel. It opens the door for fracking in Yukon, with massive destruction to our landscape and water. I am appalled that this is where the government and this crown corporation are going.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) Please provide a copy of power point presentation by YEC CEO David Morrison about the LNG project that was presented at the QUEST Conference in Ottawa on June 6, 2013. The link for the video of the presentation is: http://www.youtube.com/watch?feature=player_embedded&v=BBOuOqYvdac. How much was Mr. Morrison paid to do this presentation?

ANSWER:

(a)

Please see Attachment 1 to this response.

Please note that the presentation was about energy planning in Northern Canada and was not specifically a presentation regarding the Project or LNG as a supply option. Mr. Morrison was not paid to do this presentation.

QUEST | talks

Smart Energy in Canada's North

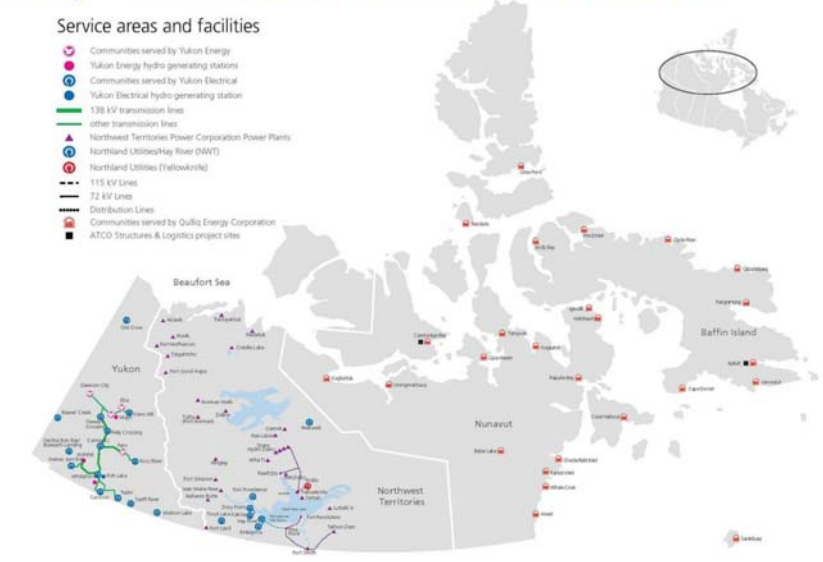
June 6, 2013

David Morrison,
President & CEO

your needs power what we do

YUKON ENERGY

Map - Service Areas and Facilities



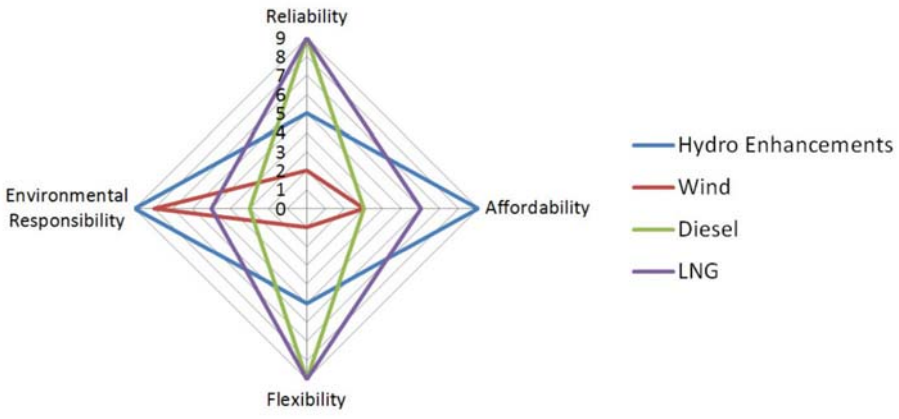
The Challenges

- Isolated systems
- No external grid connections
- Small rate base
- High cost of infrastructure development
- High fuel costs
- High electricity rates and increasing
- Rates don't reflect the true cost of energy
- Volatile demand scenarios (mining)
- Climate Change impacts
- Increasing Regulation
- Social Licence

Page 3 of 11

QUEST | talks

The Challenge - Balancing Objectives



Page 4 of 11

QUEST | talks

The Opportunities

- New supply options
- New technologies
- Reduce GHG for other sectors
- Integrated Energy Planning
- Sustainable Electricity

- Planning in Public

First Nation Partnerships

- Investment
- Social License
- as Partner
- as Proponent

Page 5 of 11

QUEST | talks

Planning in Public

- Charette process
- Public participation
- Meaningful engagement
- External experts





- All options considered/Trade-offs
- Develop and Implement a Plan
- Public Reporting
- Ongoing discussion

Page 6 of 11

QUEST | talks

Outcomes

- Planning that leads to shovel-ready projects that are government funding-ready
  - Mayo B
- Exploring ALL the options as proponent and partner
  - Biomass
  - geothermal
  - hydro enhancement
  - district heat
  - waste-to-energy
  - wind
  - solar
  - nuclear
- Private sector contributions from customers
  - Carmacks-Stewart transmission line (mining customer -- connected two grids and reduced rates!)

Page 7 of 11 QUEST | talks

Outcomes

- **Switch from diesel to LNG, BUT…**
  - developing LNG supply chain
  - LeadiNg edGe
  - Regulatory Framework
  - Financing
    - Yukon Government Debt Cap
  - Environmental Lifecycle Cost Analysis
  - Anti-fracking issues
  - competing with Renewable Resource Development
  - Supply Chain Development
    - Liquefaction Capacity
    - 2300+km supply line
  - Transportation Innovation
    - Trailer configuration
  - Regulations
  - Technology
    - Modular Engines

Page 8 of 11 QUEST | talks

Outcomes

- Energy Conservation
- District Heating
  - (Waste) Heat + Distribution

SOCIAL LICENSE

- Muted response to previous power outages and rate increase

In educating Yukoners about our operation and the challenges they face, they have become more understanding and tolerant.

Page 9 of 11 QUEST | talks

Electricity bills in comparison to Yukon

1,000 kWh/month consumption
(Residential, non-government)
Monthly bills before rate relief and taxes

YUKON - Existing	$136.05
Proposed 2012	$144.76
Proposed 2013	$154.17
Yellowknife	$254.29
NWT Thermal Zone	$491.90
Iqaluit, Nunavut	$541.90
Baker Lake, Nunavut	$635.50
Calgary	$174.69
Edmonton	$164.04
Charlottetown	$145.07
Regina	$137.92
Halifax	$136.23
Toronto	$129.01
St. John's	$109.86
Winnipeg	$73.05

Page 10 of 11 QUEST | talks


QUEST | talks
YUKON ENERGY
Page 11 of 11
QUEST talks
photos: YEC and www.archbould.com

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) Do the old diesel generators have a buyer? Who is it and how much will they be sold for?

ANSWER:

(a)

To date, YEC has not made a legal commitment to sell the Mirrlees generators.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) YEC states in their justification for this conversion that it would save on long term fuel costs. YEC have speculated that the price of LNG will remain low for the next number of years. Just recently the cost of propane and natural gas has risen by 30%. How can YEC predict in the future that they have a guaranteed price on the cost of LNG, and transportation for the next 5 years? The only guaranteed price that YEC have for the next 5 years is the production costs of LNG.

ANSWER:

(a)

Yukon Energy does not claim in the Application to have any guaranteed future price for either diesel fuel or natural gas.

Yukon Energy has prepared its Application based on the best available information. LNG fuel cost risks are addressed at page 40 of the Application, which reviews both the conservative gas price assumptions used in the economic analysis, as well as an April 2013 review by the U.S. Energy Information Administration forecast that a material gap between crude oil and US gas prices is expected to continue to 2030 and beyond. Ongoing reports of proposed large scale LNG export projects in BC are based on the same premise, i.e., that North American natural gas prices will remain materially below world oil prices well into the future.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) YEC says that one of the justifications for the project is to save money on fuel costs. How much did YEC spend on diesel for generation in each of the past 5 years?

ANSWER:

(a)

Actual diesel generation and diesel expense for each of the past five years is reviewed in response to YCS/LE-YEC-1-25(f). The Project economic assessment, however, is based on forecast long-term average diesel requirements (as explained below) and not on any forecast of actual diesel generation (which can be greatly impacted from year to year by changes in hydro generation due solely to changes in water conditions).

Please note that Board Order 2013-1 recently directed that approved revenue requirements used to set YEC's 2012 and 2013 rates in effect reflect long-term average hydro generation requirements relevant to load levels forecast for 2012 and 2013. Variances [at GRA approved fuel prices] between actual diesel generation costs and expected diesel generation costs for each year (based on actual grid loads and long term average hydro generation) are accounted for through the Diesel Contingency Fund (where funds are held in trust on behalf of ratepayers to help stabilize rates relative to cost variances caused by annual changes in hydro water flows).

Forecast long-term average grid diesel energy requirements without major new mines or new sources of Generation are reviewed in detail in Section 4.1.3 of the Application.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) Please describe how YEC will mitigate the risks of locating a volatile gas storage facility:
   i. next to one of two major access roads into downtown Whitehorse,
   ii. next to Yukon Energy's office, system control, diesel plant, major hydro dam and drinking water storage,
   iii. in close proximity to the Whitehorse airport airspace,
   iv. within 500 m to the community of Riverdale,
   v. four schools are located in Riverdale;
   vi. How can this be considered good planning in ensuring the safety and well being of Yukoners?

ANSWER:

(a)

Please note that stringent standards and regulations for design, construction and operation for LNG transport, storage and vapourization facilities have developed over the last 40 years to prevent accidents and minimize the adverse impacts of events.

Potential adverse effects on health and safety related to possible accidents and malfunctions will be addressed through a comprehensive range of measures, including application of existing non-discretionary legislation, standards and codes, regulators' responsibility to ensure safety through regulation of the Project, and safety measures being applied by the proponent, including primary containment, secondary containment, safeguard systems and separation distances. Based on these measures, the Project's adoption of a new fuel (LNG and natural gas) will be properly and prudently managed in the same way as current WTGS facilities properly and prudently manage operations with diesel fuel.

LNG facilities must comply with *Yukon Gas Facilities Regulations*, as well as the CSA Z276-11 standard. These are the governing documents outlining the requirements to be met by a proponent for production, handling and processing of a liquefied natural gas facility to ensure public safety. Yukon Energy must meet all the requirements set in both documents for the construction and operation of the proposed facility. See the response to YUB-YEC-1-7 for a detailed review of the safety measures being undertaken and implemented by Yukon Energy.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) What emergency measures and training program for fire fighters and YEC staff are in place? Has there been an anonymous poll of YEC staff to see if they support the project?

ANSWER:

(a)

YEC is implementing training on LNG for managers and operations staff. YEC will also implement an incipient fire brigade, and is working with local authorities on joint response training in the unlikely event of a LNG release and natural gas fire. See the response to YUB-YEC-1-7 for a detailed review of the safety measures being undertaken and implemented by Yukon Energy.

No survey of employee staff has been completed.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) In normal winters Whitehorse has climate inversions in the valley. Has YEC done any ice fog modeling to better understand where the LNG would end up in the case of a leak? How will YEC mitigate the problem of ice fog coming from the LNG fired generators?

ANSWER:

(a)

An LNG spill will condensate water vapour present in the air. However, it should be noted that an LNG spill is a very unlikely event. Any spill would need to occur on a given day where ambient conditions would be conducive to ice fog formation. Provisions were included in the site design to maintain any natural gas plume resulting from an LNG spill to 2.5% LNG vapour in air at the property limit. As such, any potential contribution to ice fog formation is expected to be minimal and localized to the site. Other sources of water vapour are expected to have a greater contribution to ice fog conditions such as the Yukon River.

With respect to emissions from the gas-fired generators, YEC commissioned SENES consultants to complete a modeling study of air emissions resulting from the combustion of natural gas for various compounds such as nitrous oxide, sulphur oxide, carbon monoxide and particulate matter. Water vapour was not included as part of the assessment. The findings of the modeling study are publicly available.

Comments are provided below directly on the matter of vapour emissions, reviewing the local context as well as examination of potential effects and mitigation measures if specific issues occur.

Any vapour from the engines at the Whitehorse Thermal Generating Station (WTGS) needs to be viewed in the context of the significant water vapour emission sources located near the facility, such as the large year-round open water leads on the Yukon River directly downstream of the two hydro plants. Any observer in the area of the Whitehorse Rapids Dam on a cold morning or in the deep cold of winter can clearly see the valley-filling contribution of water vapour (and resulting fog) that is emitted by the Yukon River. Other proportionally significant contributors to water vapour emissions in the area include the daily contributions of the 1,000 or more passenger vehicles and home heating appliances from the over 2,000 residential units located in nearby Riverdale.

Despite the quantitative uncertainty associated with the magnitude of the component contribution of the thermal generating station in comparison to the other water vapour sources mentioned above, the mitigation measures for any potentially significant effects that may be caused by ice fog are already practiced by residents (e.g., more vigilant driving practices) and implemented by municipal and territorial authorities (e.g., road sanding, signage) to deal with such issues. As a way of ensuring that the latter of the aforementioned mitigation measures, in particular, is effective Yukon Energy will commit to monitoring road conditions along Robert Service Way adjacent to the WTGS in cooperation with the City of Whitehorse and/or Yukon Government Public Works departments during ice fog conditions to determine whether conditions along Robert Service Way are impacted by the operations of the WTGS. If such impacts occur, it is clear that there are technically and economically feasible ways to address such effects and Yukon Energy will work with the appropriate authorities to ensure appropriate response mechanisms are in place.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) Please provide all the comments from the YESAB review of this project. In their submission to YESAB the TAAN First Nations have withdrawn from a proposed agreement that would see their Government be partners with YEC and Kwanlin Dun.

b) Is TAAN's main reason for withdrawing from the agreement based on the connection they see LNG as being eventually related to fracking in the shale deposits in the Yukon? Will the source of the LNG be guaranteed to be not hydraulically fractured for the 40 year life of the project?

c) Can Jumping Pound guarantee that it's product is not fracked?

ANSWER:

(a)

The YESAB comments are publically available on the YESAB on-line registry. It is expected that intervenors have access to the registry and are able to put forward any relevant submissions as evidence as part of the public hearing process.

(b) and (c)

Yukon Energy cannot comment on the reasons why Ta'an decided to withdraw from discussions with Yukon Energy and Kwanlin Dün. Ta'an has provided their own comments regarding the Project on the YESAB public registry.

Yukon Energy can confirm its understanding that the current planned source of supply for the Project from Calgary will be from conventional gas.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) In the last 10 years YEC has had opportunities to put in place sustainable and long term renewables. Why have YCS [sic] spent millions on consultants instead of installing solar, wind, bio-mass etc generation in the Yukon?

ANSWER:

(a)

Yukon Energy disagrees with the assertion that it has ignored opportunities to put in place sustainable and long term sources of renewable supply. Yukon Energy has rigorously pursued opportunities to advance and develop renewable generation and transmission projects that have reduced reliance on diesel generation and also reduced costs (and consequently rates) for ratepayers.

Yukon Energy has invested or secured over $200 million during the past decade or more to complete a number of projects that have directly contributed to enhancing Yukon's renewable resource capability and lowering Yukon's reliance on fossil-fuel based generation. The following are examples of Projects completed by Yukon Energy that have reduced reliance on diesel generation while providing continued low cost and renewable supply of energy on the Yukon grid:

- Completion of the Mayo-Dawson Transmission Line effectively eliminated baseload diesel generation requirements in Dawson and Stewart Crossing.

- Completion of CSTP- Stage 1 in 2008 allowed Minto mine and Pelly Crossing to connect to the WAF grid reducing potential diesel emissions from these sources.

- Completion of the Carmacks-Stewart Transmission Project (CSTP) connected the WAF and Mayo-Dawson grids, expanding the range of customers accessed by renewable generation located on each grid;

- Completion of the Mayo B Hydro Enhancement Project and the Aishihik Third Turbine expanded Yukon Energy's hydro generation capability on the new Integrated Grid more than 22% (from 76 MW to 93 MW) with forecast reductions in long-term average diesel generation from these new projects estimated to be in excess of 20 GW.h per year in 2012 and 2013[1].

As noted in the Application (Section 4.1.2), Yukon Energy is continuing to look at potential near-term hydro enhancement projects such as Mayo Lake Enhanced Storage and Marsh Lake (Southern Lakes) Storage, and for future consideration, when long term loads can justify such developments, Yukon Energy is also pursuing a wind development that could range up to 20 MW at Techo (formerly Ferry Hill) in the Stewart Crossing area, as well as potential future hydro generation at various potential greenfield sites.

Please see also response to YCS/LE-YEC-1-60(a).

[1] See YEC 2012/13 General Rate Application (page 1-4 and 1-5) - reduction in long-term average diesel generation from these new projects forecast in 2012 at 23.9 GW.h and in 2013 at 26 GW.h (forecast grid generation loads at range of 416 to 430 GW.h/year).

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) I note that YEC is partnering with Western Copper and Gold on the designing and permitting of trucks, please describe why YEC has not partnered with a major industrial customer on developing renewable energy projects in the past 10 years?

ANSWER:

(a)

Please note that YEC partnered with Western Copper & Gold on LNG supply chain development to reduce transportation costs which represents approximately one-third of the variable cost of the LNG delivered to Whitehorse.

Yukon Energy has worked with major industrial customers over the past ten years to develop and utilize the system in a manner that has reduced GHG emissions and led to rate reductions for ratepayers. The key example in this regard is the negotiation of the Power Purchase Agreement with Minto mine. Minto mine was in operation using diesel generators. Under the Power Purchase Agreement Minto agreed to make a contribution towards Stage 1 of the Carmacks-Stewart Transmission (CSTP) line and to fully pay for the costs of the spur line from the mine site to the CSTP main line. The connection of the mine to the grid allowed for sales of surplus hydro generation from the WAF system (that would otherwise be spilled) to Minto under Rate Schedule 39. This allowed for a rate reduction in the 2008/2009 test years.

As new greenfield supply options such as wind or hydro require large and stable loads to develop, Yukon Energy continues to engage with existing and potential Yukon industrial customers in order to explore opportunities to further develop the existing grid or to develop new, renewable sources of supply cost effectively.

Utilities Consumers' Group
(UCG)

TOPIC:

REFERENCE:

December 9, 2013 Application, page 2 and cover letter

"On November 22, 2013, the Commissioner in Executive Council designated the Whitehorse Diesel – Natural Gas Conversion Project as a regulated project under Part 3 of the Public Utilities Act pursuant to OIC 2013/200".

PREAMBLE:

QUESTION:

a) Please provide a copy of all information provided to the Commissioner in Executive Council that convinced the Yukon government to designate this proposed project as a regulated project and details of the process that led to this designation.

ANSWER:

(a)

OIC 2013/200 designating the Project as a "regulated project" under Part 3 of the *Public Utilities Act* is a specific direction of the Yukon Government – Yukon Energy provided no information to the Commissioner in Executive Council that convinced the Yukon government to designate the Project and cannot comment on the internal processes of the Yukon Government that led to the designation.

TOPIC:

REFERENCE:

Board Order 2013-03, Appendix A, paragraph 13

"The Board agrees with UCG's comments regarding the filing of electronic spreadsheets such as Excel with formulae intact. The filing of the electronic version of schedules and tables allows for more efficient testing of the provided information. As a result, the Board directs that, in future, YEC will include Excel versions, with formulae intact of all schedules and tables used to support its filings."

PREAMBLE:

QUESTION:

a) Please provide Excel versions, with formulae intact, of all schedules and tables that have been submitted as part of this Application along with the detailed calculations and source data behind the summary schedules and tables provided in the Application.

b) For figure 3-1, please provide source data, assumptions and detailed calculations in Excel format of the Annual Ratepayer Cost for Capital & Fuel.

c) For figure 4-1, please provide source data, assumptions and detailed calculations in Excel format of the Capital Cost & LNG Fuel Cost Savings Sensitivity analysis.

d) For figure 4-2, please provide source data, assumptions and detailed calculations in Excel format.

e) For figure C-1, please provide source data, assumptions and detailed calculations in Excel format.

ANSWER:

(a) through **(e)**

Please see Attachment 1 to this response, which as per the Board's direction in Order 2013-3, provides Excel versions, with formulae intact, of all schedules and tables used to support the Application. Source data and assumptions are reviewed as part of the Application. Source data and assumptions are as provided in the Application.

TOPIC:

REFERENCE: YEC Web Site – Making Sense of LNG

"Yukon Energy had not really explored natural gas until we hosted the 2011 Energy Charrette. Yukoners asked us to do further research into this potential fuel source, and we have spent considerable time doing that."

PREAMBLE:

QUESTION:

a) Please provide specific evidence from the 2011 Energy Charrette of Yukoners asking YEC to conduct further research into LNG.

ANSWER:

(a)

The Energy Charrette participants adopted the F.A.R.E. principles (Flexibility, Affordability, Reliability and Environmental Responsibility) that provided the context for evaluating and proposing the LNG option. See the response to YCS/LE-YEC-1-21(c) for a more full description of the direct connection of the results of the Energy Charrette providing an impetus for further research into LNG.

TOPIC:

REFERENCE: December 9, 2013 Application, page 1

"In Yukon Utilities Board Order 2013-1 dated March 25, 2013 relating to regarding Yukon Energy's 2012/2013 General Rate Application, noted that the YUB agreed that LNG powered thermal generation, at this time, appears to be a viable project."

PREAMBLE:

QUESTION:

a) Please confirm that what the Board stated in Order 2013-1 was that it at that time and based on the preliminary information available that LNG appeared to be a viable project.

b) Please provide evidence that the YUB has addressed the proposed LNG project in any other Board Order or decision.

ANSWER:

(a) and **(b)**

In Order 2013-1, the Board provided its views regarding the deferred costs related to LNG and noted that "at this time", i.e., at the time of issuance of Order 2013-1 following the review of the Yukon Energy 2012/2013 GRA, and based on the evidence filed and reviewed as part of the GRA, the Board agreed that LNG appeared to be a viable project and that all costs should remain in WIP until the Project was completed. Aside from procedural Order 2014-1, 2014-2 and 2014-3 the Board has not to YEC's knowledge addressed the proposed LNG project in any other Order or decision.

The above referenced quote is a direct quote from Order 2013-1 – the full paragraph 384 of Order 2013-1 setting out the views of the Board regarding deferred costs related to liquefied natural gas (LNG) is excerpted below:

The Board notes YEC's submission that it is seeking ways to optimize both the procurement of LNG and power generation using LNG. The Board considers that there appears to be a more direct link to these expenditures and a likelihood of cost effectively generating electricity from these expenditures. ***Therefore, the Board agrees with YEC that LNG, at this time, appears to be a viable project. All costs should remain in WIP until the project is completed.*** The Board notes that YEC has stated on page 5-45 of the Application that "… further feasibility work is required to determine the optimum way to secure the LNG, the required timing and all related costs (including assessment of potential options for LNG supply chain development jointly with other interests to meet broader near and longer term Yukon opportunities)." Since the mention of other interests and other opportunities brings the direct applicability of any supply chain costs to ratepayers into question, the Board rules that any costs relating to supply chain, as opposed to the economic viability of generating electricity, will not be paid by ratepayers until YEC demonstrates that those costs are solely for the benefit of ratepayers of electrical energy ***[emphasis added].***

TOPIC:

REFERENCE: Board Order 2013-01, Reasons for Decision, Page 79

"Since the mention of other interests and other opportunities brings the direct applicability of any supply chain costs to ratepayers into question, the Board rules that any costs relating to supply chain, as opposed to the economic viability of generating electricity, will not be paid by ratepayers until YEC demonstrates that those costs are solely for the benefit of ratepayers of electrical energy."

Minister's Referral to YUB (December 20, 2013) - Terms of Reference

"The YUB shall report on and make recommendations about the necessity for the Whitehorse Diesel-Natural Gas Conversion Project and its timing and design, with particular regard to:

c. The risks facing the Whitehorse Diesel-Natural Gas Conversion Project and their potential impacts on rates for customers."

PREAMBLE:

QUESTION:

a) Please provide an analysis showing that the capital and operating costs of the proposed facilities will be incurred solely for the benefit of Yukon electricity ratepayers.

b) Please provide short and long term cost / benefit analysis of the proposed project that clearly shows the full impact on YEC's currently approved revenue requirement of the proposed project. This analysis should indicate expected increases in revenue requirement expected due to other cost drivers and capital expenditures as well as a clear indication of where ratepayers will see a reduction in rates as a result of this project.

c) Please provide details of the actual and expected use of and cost of diesel fuel for standby generation in Whitehorse for 2010 through 2018 as well as the

amount of energy generated by Whitehorse standby diesel generation in these years.

ANSWER:

(a) and **(b)**

The Application includes analysis showing: (a) that the capital and operating costs of the Project will be incurred for the benefit of Yukon electricity ratepayers in order to meet required capacity planning requirements while securing fuel and overall cost savings (this includes all planning and other costs included with regard to LNG transportation); (b) that, based on diesel and natural gas generation costs being included in rates based on long-term average hydro generation, the benefits to ratepayers are forecast to exceed the costs starting in the first full year of operation as well as in subsequent years over the economic life of the Project; and (c) that the Project's economic and ratepayer cost savings are very robust in the context of potential adverse risks related to forecast capital costs for the Project, fuel cost savings per kW.h with the Project, and grid diesel displacement volumes achieved with the Project.

In summary, the Application confirms that the expected net impact of the Project in each year is to reduce costs charged to ratepayers.

YEC is not attempting to forecast overall revenue requirements, rates, or components of YEC revenue requirement, in the Application, i.e., such matters are addressed in a GRA.

(c)

Actual diesel generation at Whitehorse in 2010 to 2013 was as follows (reflects actual generation for 2010 and 2011, and actual generation rather than long-term average generation for 2012 and 2013[1], at GRA approved fuel prices)[2]:

[1] In 2012 and 2013, diesel costs to YEC are based on long-term average rather than actual diesel generation requirements; however, long-term average diesel allocation to Whitehorse has not been estimated. In addition, actual generation includes diesel generation at Whitehorse for capital projects or RFID (it is not possible to separate out such costs for different plants or units).

[2] 2010 and 2011 fuel cost based on 2009 GRA approved fuel efficiency and fuel price for Whitehorse; 2012 and 2013 based on 2012/13 GRA fuel cost.

- 2010 at 2.417 GW.h or $0.6 million
- 2011 at 6.570 GW.h or $1.7 million
- 2012 at 2.205 GW.h or $0.6 million
- 2013 at 0.840 GW.h or $0.2 million

Forecast default diesel generation for the grid with Base Case (no Alexco), as well as other load scenarios, for 2014 to 2018 assuming long-term average annual hydro generation is provided in Table C-2 of Appendix C of the Application. As reviewed in the response to YUB-YEC-1-36(b), these forecasts address generation required under normal operation and do not include other potential requirements that may arise in practice. The cost for this forecast default diesel generation will vary depending on the assumed generation and fuel price, e.g., generation with existing diesel units at approved 2012/13 GRA fuel prices will cost 28.7 cents/kW.h (Whitehorse fuel price at $1.0513/litre), while updating this price to current YEC diesel fuel prices will cost about 32.6 cents/kW.h (Whitehorse fuel price at $1.1933/litre - see response to YUB-YEC-1-42(c)).

TOPIC:

REFERENCE: Reference: December 9, 2013 Application, page 2

"A proposal for the Whitehorse Diesel-Natural Gas Conversion Project was submitted in August 2013 to the Yukon Environmental and Socio-economic Assessment Board ("YESAB") under the Yukon Environmental and Socio-economic Assessment Act, and is currently subject to a screening by the Executive Committee of YESAB."

PREAMBLE:

QUESTION:

a) Please describe any differences between the proposed project being addressed in this Part 3 review and the project being addressed by the YESAB.

b) Please provide details of the amount of YESAB-related costs that have been incurred to date and forecast, separated by year. Please ensure that the detail provided is not simply a single number but an actual breakdown of the types of costs incurred.

c) Please confirm whether all costs incurred related to this project will be recovered from Yukon ratepayers.

d) Please confirm YEC's agreement that all materials on the public record of the YESAB review process are also now part of the YUB's review process and subject to reference and questioning.

ANSWER:

(a)

The proposed Project being reviewed by the Yukon Utilities Board is the same as the proposed Project being reviewed by the Yukon Environmental and Socio-economic Assessment Board (YESAB).

The Project as defined in the Terms of Reference provided by the Minister to the Board is to "modernize the existing Yukon Energy Corporation Whitehorse Thermal Generating Station to meet growing requirements for reliable and flexible thermal generation on the Yukon grid including the replacement of two diesel generating units (9.1 MW total capacity) scheduled for retirement by 2015 with up to three new modular natural gas-fired generating units (13.1 MW total capacity) supplied by liquefied natural gas (LNG), and the installation of LNG truck offloading, storage, vapourization and related infrastructure". This is essentially the same description of the Project provided at page 1-1 of the YESAB Project Proposal (revised November 2013).

Due to differences in timing between filing YESAB Project Proposal and the Part 3 Application there are differences in some of the specific details included in each document. For example, the load forecast and economics filed with the YESAB Project Proposal (August 2013) were updated in the Part 3 Application (filed December 2013). Yukon Energy has provided specific updates in this regard to YESAB as part of the information request process, e.g., the January 29, 2014 response to information requests on the Project Yukon Energy provided YESAB with updated information regarding the load forecast and Project economics provided in the Part 3 Application.

Further, with regard to final design, as noted in a letter to YESAB dated November 15, 2013, "additional changes to site layout and related components may occur during final design of the Project, subject in each instance to the restrictions that they be confined to the YEC-acquired property area within the Expanded Site Area and the vapour barrier requirements to comply and conform with the requirements of CSA Standard Z276-11: Liquefied Natural Gas (LNG) Production, Storage and Handling, as assessed in the vapour dispersion analysis. Based on these restrictions, our further understanding is that any such final design changes will not affect the environmental or socio-economic effects assessment of the Project as provided in the revised Project Proposal."

(b)

Please see response provided to YCS/LE-YEC-1-11(f).

(c)

YEC intends to seek recovery through rates of all Project costs. Project costs to be recovered from ratepayers will be determined by the Yukon Utilities Board as part of a future revenue requirement proceeding.

(d)

YEC certainly understands that all materials on the public record of the YESAB review process are "on the public record", and can therefore be referenced in the current proceeding. YEC has referenced such materials [which are on the YESAB website as filed] where it believes the information would assist parties, without requiring that all such materials be duplicated formally on the record of the current proceeding.

The Board's letter of February 24, 2014 to all parties in this proceeding has provided clear direction on this matter, and states as follows:

> "The Board notes YEC's reference in its Application before the Board to its YESAB project proposal, referring to the YESAB on-line registry and information on the YEC website. The Board considers that this reference is for informational purposes only. The Board will not receive into record of this proceeding all of the documents from the YESAB or YEC websites. If there are specific documents that a party wishes to use during the Board's proceeding that party must file those in evidence."

TOPIC:

REFERENCE: December 9, 2013 Application, Page 4

"The Project scope will involve replacing two diesel generating units scheduled for retirement in the existing WTGS by 2015 (9.1 MW total capacity) with three new modular natural gas-fired generating units (13.1 MW total capacity), and the installation of LNG truck offloading, storage, vapourization and related infrastructure on the Expanded Site Area. Two natural gas-fired units (8.8 MW total capacity) are anticipated to be in service Q4 2014 to provide capacity and fuel cost savings during the winter of 2014/2015. Projected in-service for the third natural gas-fired unit (4.4 MW) will occur as required to meet grid capacity planning requirements, and is anticipated to be within a few years after the first two units are in service. The estimated capital cost (2013$) for the Project is $38.8 million, with $34.4 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."

PREAMBLE:

QUESTION:

a) Please confirm that none of the projected costs of this proposed project will be recovered in YEC's rates until the YUB approves the addition of prudently incurred costs into YEC's rate base as part of a general rates application.

b) Please provide a breakdown of how this proposed project will be financed and a breakdown of the estimated overall impact on components of YEC's revenue requirement.

c) Prior to this current application, has YEC submitted anything to the YUB indicating that two diesel generating units were scheduled for retirement in 2015? If yes, please provide details and details of any review the YUB has undertaken of such a proposed retirement.

d) Please confirm that the KPMG depreciation study submitted in YEC's 2012-2013 GRA identified a remaining life of 13 years with respect to YEC's diesel-fuelled

generating equipment based on the concluded effective age and the remaining area under the survivor curve.

e) Please provide a copy of YEC's current asset retirement plan including details of the calculations associated with the remaining life of its diesel-fuelled generating units.

f) Please provide analysis showing that the two diesel-fuelled generating units identified in this proposed project as scheduled for retirement in 2015 are the units that must be retired ahead of other diesel-fuelled generating units.

ANSWER:

(a)

Confirmed.

(b)

The Project will be financed as part of normal rate base, and it is assumed that the normal rate base will be financed 60:40 debt: equity. YEC is not attempting to forecast overall revenue requirements, or components of YEC revenue requirement, in the Application, i.e., such matters are addressed in a GRA.

(c)

YUB-YEC-1-11(b) Attachment 1 and YECL-YEC-1-12(c) Attachment 1 (each filed during the YEC 2012/2013 General Rate Application) provided the YEC Generation Inventory and noted the planned retirement dates for WD1 and WD2 are 2014 and 2015 respectively. YEC is not aware of any specific YUB comment on this information.

(d)

Confirmed. For clarity, this number applies to <u>all</u> diesel units in YEC's inventory of engines at the time (not just WD1 and WD2). The study acknowledged that WD1 and WD2 were planned for retirement in 2013 at the time the study was prepared.

Table 1 below was filed as part of YEC 2012/13 GRA in response to YECL-YEC-1-55 and indicates the asset retirement schedule as of December 31, 2010 that was used as supporting information for the analysis undertaken by KMPG in the Depreciation Study filed with the 2012/2013 GRA. Please note that the asset retirement plan is constantly being updated based on the best information at the time. Please see part (e) below for the asset retirement plan.

Table 1:
Diesel Generation Fleet

Diesel Generation Fleet					
Location	Unit Number	Capacity (kW)	In-Service Date	Planned Retirement Date	Age at Retirement
Faro	FD1	5,150	1970	2021	51
Faro	FD3	1,000	1989	2019	30
Faro	FD5	1,400	1990	2020	30
Faro	FD7	3,000	1992	2027	35
Dawson	DD1	800	1988	2018	30
Dawson	DD2	1,000	1987	2017	30
Dawson	DD3	1,000	1990	2020	30
Dawson	DD5	1,500	1996	2031	35
Mayo	MD1	1,000	1989	2019	30
Mayo	MD2	1,000	1989	2019	30
Whitehorse	WD1	3,920	1968	2013	45
Whitehorse	WD2	5,150	1968	2013	45
Whitehorse	WD3	5,150	1970	2021	51
Whitehorse	WD4	2,500	1975	2025	50
Whitehorse	WD5	2,500	1975	2025	50
Whitehorse	WD6	2,700	1990	2025	35
Whitehorse	WD7	3,300	1991	2026	35
Mobile	YM1	1,400	1990	2015	25
Mobile	YM2	150	1999	2024	25
Mobile	YM3	125	n/a	n/a	n/a
Mobile	YM4	35	n/a	n/a	n/a

(e)

Please see Attachment 1 of this response for a copy of the Asset Retirement Plan. The asset retirement plan is assessed continuously based on Yukon Energy's understanding of actual and forecast of use and condition of the units.

(f)

As per the YEC Generation Inventory filed in IR responses during the 2012/2013 General Rate Application, WD1 and WD2 have been in service since 1968 and are scheduled for retirement in 2014 and 2015 respectively. Please see also responses to YUB-YEC-1-13(a) for business case for life extension versus replacement; and YECL-YEC-1-7 for information regarding operating hours and last rebuild.

YEC GENERATION INVENTORY *2011*

LOCATION	***UNIT NO.***	***PRIME MOVER TYPE***	***NAME PLATE CAPACITY***	***MCR RATING (kW)***	***GEN. RATING (KVA)***	***GEN. VOLTAGE (V)***	***IN-SERVICE DATE***	***PLANNED RETIREMENT DATE***	***Gross Fuel Eff. (KWh/ltr)***
Aishihik				37,000					
	AH1	hydro	15,600	15,000	19200	13800	1975	none	
	AH2	hydro	15,600	15,000	17000	13800	1975	none	
	AH3	hydro	7,200	7,000	8250	13800	2011	none	
Faro				8,850					
	FD1	diesel	5,150	4,000	6000	12000/6900	1970	2021	3.7
	FD3	diesel	1,000	850	1250	4160	1989	2019	3.7
	FD5	diesel	1,400	1,200	1800	4160	1990	2020	3.7
	FD7	diesel	3,000	2,800	3750	4160	1992	2027	3.9
Dawson				3,960					
	DD1	diesel	800	720	1000	2400/4160	1988	2018	3.7
	DD2	diesel	1,000	920	1250	4160	1987	2017	3.7
	DD3	diesel	1,000	920	1288	4160	1990	2020	3.7
	DD5	diesel	1,500	1,400	1875	4160	1996	2031	3.9
Mayo				17,100					
	MD1	diesel	1,000	850	1250	4160	1989	2019	3.7
	MD2	diesel	1,000	850	1250	4160	1989	2019	3.7
	MH1	hydro	2,620	2,600	2550	6900	1957	none	
	MH2	hydro	2,840	2,800	2550	6900	1951	none	
	MBH1	hydro	5,693	5,000	5,693	6900	2011	none	
	MBH2	hydro	5,693	5,000	5,693	6900	2011	none	
Whitehorse				62,500					
	WH1	hydro	5,800	5,800	5800	6900	1958	none	
	WH2	hydro	5,800	5,800	5800	6900	1958	none	
	WH3	hydro	8,400	8,400	8400	6900	1969	none	
	WH4	hydro	20,000	20,000	2360	6900	1984	none	
	WD1	diesel	3,920	3,500	4250	6900	1968	2014	3.7
	WD2	diesel	5,150	4,500	6000	6900	1968	2015	3.7
	WD3	diesel	5,150	4,500	6000	6900	1970	2021	3.7

	WD4	diesel	2,500	2,250	3000	4160	1975	2025	3.6
	WD5	diesel	2,500	2,250	3000	4160	1975	2025	3.6
	WD6	diesel	2,700	2,500	3125	4160	1990	2025	3.7
	WD7	diesel	3,300	3,000	4125	4160	1991	2026	3.9

Haeckel Hill				810					
	WW1	wind		150			1993	2018	
	WW2	wind		660			2000	2025	

Total Co 4 Capacity **130,220**

Mobile Diesels				1,610					
	YM1	diesel	1,400	1,300		4160	1990	2015	3.7
	YM2	diesel	150	150	150	347/600	1999	2024	
	YM3	diesel	125	125		277/480			
	YM4	diesel	35	35		277/480			

TOPIC:

REFERENCE: December 9, 2013 Application, Page 5

"LNG truck offloading, storage, and vapourization facilities and related infrastructure, including up to three 166.5 m³ and two 120 m³ storage tanks, a short all weather access road from Miles Canyon Road for truck offloading and access to the components on the Expanded Site Area, vapour barrier, fencing and other facilities required for safe operation."

PREAMBLE:

QUESTION:

a) Please confirm that LNG cannot be odourized so there are concerns about the ability of personnel to detect health hazard concentrations of exposure to LNG.

b) Please provide copies of the studies of the geological conditions and earthquake history of the proposed LNG site and explain how these studies were used to determine appropriate design loads on the critical components of the proposed LNG plant to ensure containment during and after an earthquake as well as public safety and plant reliability in the event of an earthquake.

c) Please describe the security measures and their associated costs that are included in the proposed project. Please provide a copy of YEC's security plan for the proposed facilities.

d) Please provide a copy of any spill risk assessment for the proposed facilities and related transport activities conducted by YEC.

e) Please provide a copy of the waste management plan related to the non-hazardous and hazardous wastes expected to be generated at the proposed LNG facilities.

f) Please provide studies conducted by YEC related to noise levels from the proposed LNG facilities.

g) Please describe the post-construction reports that YEC intends to submit to the YUB which summarize plant operations, maintenance activity and abnormal events.

ANSWER:

(a)

As part of the liquefaction process, impurities are removed from the natural gas which is then cooled to a temperature of -162 ^{o}C in order to convert the gas to a liquid phase. At such low temperature, compounds used to odorize gas such as butyl mercaptan would freeze as its melting point is higher than the one for natural gas. Because LNG cannot be odorized, fixed gas detectors will be located at strategic locations to detect potential leak and activate the appropriate shutdown sequence. Safe work procedures will be implemented to ensure public and personnel safety.

Please see also response to CW-YEC-1-2.

(b)

The National Building Code of Canada (NBCC, 2010) provides seismic hazard calculations for Whitehorse to be considered as part of the design of the facility. In addition, the NBCC lists power generating stations and electrical substations within the Importance Category of Post-disaster. As such, the Code requires the inclusion of Importance Factors in the design of the facility. For instance, the Importance Factor for the structural design translates in increasing the snow, wind and earthquake loads that elements or structures must withstand. The LNG facility is an integral part of the generating station and as such all elements of the LNG facility must consider the utilization of these Post-disaster Importance Factors.

(c)

Security measures for the site include fencing around the property, installation of closed circuit televisions and adequate lighting for night supervision. The system command center operators will monitor the site 24 hours per day, 7 days a week. Capital costs for security measures are included as part of the LNG Site Development costs and are estimated to be $172,700.

(d)

Studies were conducted to analyze the risk assessment of the LNG plant and LNG transport trucks. Findings of these reports can be found within Yukon Energy's YESAB submission. These reports include thermal radiation calculation, which assessed the potential thermal radiation emitted from a natural gas pool fire in the remote impoundment, following an LNG spill. The study measured the amount of heat generated and the distance the heat would reach in the event of an LNG pool fire. Vapour dispersion modelling was also conducted, which looked at the distance natural gas vapours would travel from an LNG spill. Accidents and malfunctions were considered and looked at the risk of accidents and malfunctions of LNG transport trucks while hauling and unloading.

(e)

The Whitehorse Rapids Generation Site spill response plan contains Section 14: Waste Management, where various products are discussed for their best management, recycle and disposal. In addition to this, environmental work practices, EWP-008 Special Wastes and EWP-010 Non-Hazardous Wastes address proper waste management of hazardous and non-hazardous wastes at the Whitehorse Rapids Generation Site. However the environmental work practices cover liquid or solid wastes and do not include Mercaptan or NG as they are gasses and cannot be disposed as liquid or solid wastes.

(f)

Please see response to CW-YEC-1(j) which reviews the results of the assessment included in Chapter 7 (Effects Assessment) of the YESAB Project Proposal.

(g)

YEC will at its next revenue requirement proceeding file the necessary information with the YUB to demonstrate all incurred and planned capital costs are prudent. This is the same standard for all costs that the utility requests to be added to rate base.

TOPIC:

REFERENCE:

Minister's Referral to YUB (December 20, 2013) - Terms of Reference:

"The YUB shall report on and make recommendations about the necessity for the

Whitehorse Diesel-Natural Gas Conversion Project and its timing and design, with particular regard to:

> d. What, if any, alternatives to the Whitehorse Diesel-Natural Gas Conversion Project might be advisable given reasonable load assumptions and risk assessments."

December 9, 2013 Application, Page 7:

"New natural gas-fired engines are assumed to have an economic life of 40 years, based on expected average annual utilization of these assets. Assuming that the facilities will continue to be required for established backup capacity for the Yukon grid, it is expected that individual components will be replaced as they reach end of life and the Project facilities will not be decommissioned."

PREAMBLE:

QUESTION:

a) Please provide a copy of the analysis proving that new natural gas-fired generating units will have an economic life of 40 years. Please include details on the assumed use of these units that result in a 40 year life.

b) Please confirm that the referenced statement from page 7 of the Application means that the proposed LNG-fuelled generating units will be used only in a back-up capacity.

c) Please provide a detailed cost breakdown and risk assessments of alternative systems YEC considered before moving forward with the proposed project (e.g.,

renewable generation, demand side management, bi-fuel conversion kits that enable current diesel equipment to run on a combination of LNG and diesel, purchase of new diesel generators with no changes to warehouse, purchase of second-hand diesel generators requiring no changes to warehouse, etc.). Please provide a full business case analysis on all alternatives considered.

ANSWER:

(a)

Please see response to YUB-YEC-1-52(a).

(b)

The referenced statement addresses the expected economic life of the new natural gas fired generating units and indicates that a 40 year economic life is assumed based on the expected average annual utilization of the assets (i.e., it is not expected that they will be run all the time and may only be required to be run more frequently on a seasonal basis, or in low water years) and based on the fact that the facilities will continue to be required to meet Yukon grid capacity planning requirements.

As noted in the Application, the units are expected to provide reliable and flexible new generation capacity required today at Whitehorse to meet Yukon Energy's reserve capacity planning criteria for the Yukon grid, including reserve capacity for seasonal low water periods and drought years while supplying short term non-industrial load growth and peak winter demand. Thermal generation (whether supplied by diesel or gas) is required on the isolated Yukon grid to meet all back up generation requirements. This means that the new gas-fired generating units would be used to meet emergency back-up requirements, as well as grid loads during winter months and other periods when water availability for hydro generation is limited by seasonal or drought conditions or is otherwise insufficient to meet grid load requirements. Inability to rely on diesel generation in one or more of these circumstances would present an obvious and acute risk to human health and safety and public and private infrastructure, particularly during cold winter temperatures. In effect, the gas-fired generating units will serve the same purpose as diesel units on the grid and will be used in the same manner as the existing (or new) diesel units would be.

(c)

The Application references and reviews (Section 4.2) the alternatives that YEC reviewed before moving forward with the Project, and responses are provided in this proceeding to specific questions on any of these alternatives. There is no basis or requirement for YEC to provide a business case for alternatives that YEC is not proposing.

TOPIC:

REFERENCE: December 9, 2013 Application, Page 7

"Yukon Energy has secured an LNG supply of up to 250 m³ per day for a minimum of five years from Shell Canada's Jumping Pound LNG plant being developed near Calgary and scheduled to start operation before the end of 2014. Yukon Energy also retains the potential during the term of the Shell Canada contract to source LNG from the Fort Nelson area in northern British Columbia should additional liquefaction facilities come into service in this area, and/or Shell Canada arranges to make LNG supplies available in this area."

December 9, 2013 Application, Page 10

"Yukon Energy has secured a minimum five-year (starting from date of first delivery) flexible LNG supply of up to 110,750 kg per day (approximately 250 m³ per day) from Shell Canada's Jumping Pound production facility being developed near Calgary, which is planned to start operation before the end of 2014 with an estimated capacity of 250,000 metric tonnes per year (i.e., more than 1,500 m³ per day). LNG costs to Yukon Energy under the contract with Shell Canada will fluctuate each month to reflect the latest published monthly Alberta Energy Company (AECO) index price of natural gas as reported by the Natural Gas Exchange."

PREAMBLE:

QUESTION:

a) Please provide a copy of any agreement between YEC and Shell regarding the supply of LNG and identify which clause of this agreement guarantees the supply of natural gas will be from conventional methods of extraction.

b) Please provide an update on the current operating start date for the LNG plant at the Jumping Pound complex.

c) Please provide a copy of any agreement in place regarding securing a supply of LNG from the Fort Nelson area or any other area in British Columbia or Alberta.

d) Please provide the Alberta Energy Company (AECO) index price of natural gas as reported by the Natural Gas Exchange for January 2013 through February 2014.

ANSWER:

(a) through **(c)**

The contract with Shell is confidential to the parties. Shell separately advised YEC the fuel from Jumping Pound would be from conventional sources. This was supported by the Pembina Institute in the Life Cycle Assessment that was undertaken.

Please see response to YUB-YEC-1-4(a) as regards Yukon Energy contingencies regarding the Shell plant operations. YEC currently does not have any agreement regarding securing supply of LNG from the Fort Nelson area or any other area in BC or Alberta.

(d)

Please see response to YCS/LE-1-45 (a).

TOPIC:

REFERENCE: December 9, 2013 Application, Page 8

"Table 3-1 provides a summary of the estimated Yukon Energy capital costs of $34.4 million (approximately $3.9 million per MW) for the initial Project facilities at the WTGS to be completed prior to the end of 2014, including the first two gas-fired units and other work related to LNG facilities (truck offloading, storage, and vapourization), distribution and communication line, utility trench, and decommissioning of the two Mirrlees diesel units. These costs are preliminary estimates developed in mid-2013 based on preliminary quotes and preliminary engineering."

PREAMBLE:

QUESTION:

a) Please provide a more detailed breakdown of the costs identified in Table 3-1 including YEC's internal costs, as well as any interest and contingency component of the identified cost categories. For the "Planning Costs" category, please provide a complete breakdown of all costs incurred to date to prepare and research this project and provide documentation and receipts associated with all in-house and consultants / professional fees (similar to what is required under the YUB's Scale of Costs).

b) Please identify where in Table 3-1 the estimates costs of the current YUB review process are included. Please provide a detailed breakdown of the estimated costs of the current YUB review process.

c) Please identify where in Table 3-1 the estimates costs of the current YESAB review process are included.

d) Please identify how many YEC staff are currently certified to work with LNG as proposed in this project and where the costs of this certification are included in the projected project costs.

e) Please provide the confidence level for the $34.4 million cost estimate included in this application.

f) Please provide a current cost estimate for the components of the proposed project.

ANSWER:

(a)

Please see updated cost estimate provided as response to YUB-YEC-1-1(d), and YUB-YEC-1-2(c) regarding sunk costs for the Project.

YEC is not seeking approval of any costs in the Application, and therefore sees no basis for providing the detail requested on planning costs to date. Further, YEC notes that the level of detail and documentation requested with regard to planning costs is unprecedented either for a Part 3 review (which is focused primarily on the business case or the need and justification for the Project) or for a GRA revenue requirement review (where, outside of a specific cost awards process, there is no precedent for utilities to provide copies of specific receipts for amounts spent, or the specific division of labour for in house costs or services retained).

(b)

Please see response to YUB-YEC-1-1(d) which provides an updated Project capital cost estimate. Costs related to the YUB Part 3 review process will be deferred to the Hearing Cost Reserve Account, and as such are not included in the updated detailed Project cost estimates reviewed in YUB-YEC-1-1(d), and were also not included in the estimated costs as originally filed in the Application.

It is expected that Part 3 hearing costs will be reviewed in detail by the Board and other intervenors as part of YUB's Cost Award Process and further details may be provided at that time.

(c)

Please see response to YUB-YEC-1-1(d) which provides an updated Project capital cost estimate. Costs related to the YESAB review process are included under Planning and Permitting (Permitting and Regulatory costs). Please see response to UCG-YEC-1-6(b).

(d)

At this time, a total of 31 employees will be trained on LNG storage, handling and processing. Employees who will undergo training include environment department staffs, health and safety department staffs, electricians, mechanics, plant operators, system command center operators, engineering staff and managers. Costs are included within the Owner's costs category and are estimated at $115,000.

(e) and **(f)**

Please see response provided to YUB-YEC-1-1.

TOPIC:

REFERENCE: December 9, 2013 Application, page 43

"The key elements of the Whitehorse Diesel – Natural Gas Conversion Project have undergone extensive consultation under Yukon Energy's 2011 20-Year Resource Plan: 2011-2030 ("2011 Resource Plan"), YEC's planning for the Project's YESAB Project Proposal, and the YESAB screening of the Project Proposal Submission."

Following up on the Energy Charrette, Yukon Energy continued to host technology-specific workshops including a public workshop in Whitehorse in January 2012 on the potential use of LNG for electrical generation. Subsequent to this extensive public engagement process the draft 2011 Resource Plan was made publically available for review in July 2012."

PREAMBLE:

QUESTION:

a) Please provide details of the "extensive consultations" undertaken on the proposed project with respect to Yukon Energy's 2011 20-Year Resource Plan: 2011-2030 that was filed with the Yukon Utilities Board in July 2012 as a response to an interrogatory (YECL-YEC-1-18) during the review of YEC's 2012/2013 General Rate Application.

b) Please provide details of any regulatory review undertaken of the Resource Plan submitted on July 27, 2012.

c) Please provide details of presentations, attendees, issues discussed and feedback related to the referenced technology-specific workshops conducted for the proposed project.

d) From the January 2012 Liquefied Natural Gas Workshop, please provide a copy of the presentation by Cam Osler as well as Excel versions, with formulae intact, of all schedules and tables that were part of his presentation.

e) From the January 2012 Liquefied Natural Gas Workshop, please provide a copy of the presentation by Alan Hatfield as well as Excel version, with formulae intact, of all his chart of slide 16 regarding a comparison of diesel and gas prices as well as the source documents for his analysis.

f) From the January 2012 Liquefied Natural Gas Workshop, please provide a copy of the presentation by Don McCallum as well as evidence related to his claim on slide 4 that "Natural gas is a cleaner burning fuel compared to diesel resulting in fewer human health-related emissions". Also provide Excel versions, with formulae intact, of all schedules and tables that were part of his presentation as well as the source documents for the data he used to develop his presentation.

ANSWER:

(a)

To be clear, consultation undertaken with respect to the 2011 Resource Plan did not specifically relate to, or address, the proposed Project as defined in the YESAB Project Proposal or in the Part 3 Application. The Yukon Energy Charrette, LNG technology workshop and 2011 Resource Plan addressed LNG as a potential supply option for Yukon (the specific Project at that time was not defined).

However, there was extensive consultation with stakeholders and members of the public that informed the 2011 Resource Plan and Yukon Energy consulted with the public on the draft 2011 Resource Plan made publically available for review in July 2012. Yukon Energy also had a public workshop in Whitehorse in January 2013 on the potential use of LNG for electrical generation. This process is summarized in Section 5.1.1 of the Part 3 Application.

With regard to the draft 2011 Resource Plan, public meetings to review the draft 2011 Resource Plan were held in seven Yukon communities (Whitehorse, Dawson, Faro, Watson Lake, Mayo, Haines Junction and Carmacks) during August and September, 2012. The summary of the consultation process regarding the draft 2011 Resource Plan is publically available on Yukon Energy's website.

(b)

The Overview of the 2011 20-Year Resource Plan: 2011-2030 (Overview) was provided as a response to an interrogatory request during the Yukon Energy 2012/2013 GRA (see YECL-YEC-1-18 Attachment 1 filed July 27, 2012). The 2012/2013 proceeding provided the Board and parties the opportunity to ask questions about the Overview and draft 2011 Resource Plan. Board Order 2013-01 addressed LNG thermal powered generation as a result of information provided during the 2012/13 GRA (see UCG-YEC-1-4(a)).

Apart from the YEC GRA proceeding, there was no other process available for regulatory review of the 2011 Resource Plan, i.e., such processes must typically be initiated by ministerial direction pursuant to the *Public Utilities Act*, e.g., Part 3 proceedings to review designated energy projects.

(c)

Please note that the January 2012 Liquefied Natural Gas Workshop focused on LNG as a supply option for Yukon (generally) and was not focused on the Project as defined in the Part 3 Application (or in the YESAB Project Proposal). The workshop report completed subsequent to the January 2012 Liquefied Natural Gas Workshop is publically available on Yukon Energy's website. This report provides a summary of workshop objectives, participants, presentations and discussions, and is provided as Attachment 1 to this response.

(d) through **(f)**

The referenced presentations from the January 2012 Liquefied Natural Gas Workshop are publically available on Yukon Energy's website.

The January 2012 workshop focused on LNG as a potential supply option (and did not relate specifically to the Project as defined in the Part 3 Application). While the information contained in these presentations is useful, it is not directly relevant to understanding and assessing the Project being proposed in the Application.

As these presentations were prepared by third parties over two years ago, Yukon Energy does not have ready access to any excel files underlying these presentations, is

not readily able to provide this information and does not see the relevance it would have to assessing the Project before the Board.

Liquefied Natural Gas Workshop Report



(Photo from Cam Brown's presentation)

January 18th 2012, at the Gold Rush Inn in Whitehorse

1. Introduction

At the Yukon Energy Charrette in March 2011, Yukon Energy brought together governments, Yukoners and energy experts from across Canada for three days to discuss and share information on resource options for Yukon's energy future. One of the key outcomes from the charrette was Yukon Energy's commitment to continue engaging stakeholders, governments and the public in planning for the future. To meet that commitment and plan in public, Yukon Energy is holding energy workshops on a series of topics and resource options. The Liquefied Natural Gas (LNG) Workshop is Yukon Energy's third workshop.

The information gathered from the workshops and public meetings will be used to inform and direct the work of Yukon Energy and its consultants in carrying out the resource options planning.

This is the report from the LNG Workshop and Public Meeting held on January 18th, 2012 in Whitehorse.

2. Workshop Objectives

The following workshop objectives were developed:

1. Examine LNG in the context of Yukon Energy's planning principles: reliability, affordability, flexibility, and environmental responsibility;
2. Identify the environmental and socio-economic issues and opportunities in relation to LNG in Yukon;
3. Educate the participants as to how LNG fits within the Draft YE Resource Plan;
4. Understand the regulatory framework for LNG; and
5. Understand the technology and the individual parts and locations of the LNG supply chain.

3. Workshop Participants

Over 65 invited and interested workshop participants attended the half day session. Participants represented the following stakeholders, governments and industry:

Government of Canada

City of Whitehorse

Kluane First Nation

Vuntut Gwitchin First Nation

Yukon Conservation Society

Yukon Utilities Consumer Group

Government of Yukon (Oil and Gas, Forest Management, Building Safety, Business and Economic Development, Yukon Geological Survey)

Village of Carmacks

Whitehorse Chamber of Commerce

Yukon Cold Climate Innovation Centre

Council of Canadians	Access Consulting
EnCana	Selwyn Resources
ATCO Midstream	Adanac Molybdenum Corporation
Northern Cross Yukon	Dimok Timber
Dempster Energy Services	Western Copper and Gold
Kerr Wood Leidal Associates	Interested Public
Yukon Electrical Company	

The workshop was also attended by Yukon Energy staff and consultants. The public meeting in the evening was attended by 35 people.

4. Presentations

The workshop provided the opportunity for Yukon Energy to share the findings from the LNG Transition Option Background Paper with the participants as well as for key stakeholders, partners and governments to present their information. The following presentations were delivered at the workshop and are posted on the Yukon Energy website at www.yukonenergy.ca/energy/public_engagement/lng/.

a) ***LNG Fundamentals***. Alan Hatfield PE, Vice President LNG Technical Services Braemar Wavespec, Houston, Texas.
b) ***Transforming Resources into Mines; the Casino Mine Story.*** Cameron Brown, VP Engineering, Western Copper and Gold.
c) ***LNG Transition Fuel Option for Yukon***. Cam Osler, Intergroup Consultants Ltd.
d) ***Developing Yukon's Natural Gas***. Presentations by David Thompson, President Northern Cross and Rob Daub, CEO Dempster Energy Services.
e) ***Regulation of LNG Energy in the Yukon.*** Ron Sumanik, Acting Director, Oil & Gas Resources, YG.
f) ***Examining the Environmental Impacts and Opportunities of LNG for Yukon.*** Don McCallum P.Eng., Morrison Hershfield.

5. Workshop

Following the presentations the participants were organized into facilitated groups ranging from 6 to 8 people. The groups were asked to discuss and record their ideas and comments with the intention of the work being shared with the participants, the public and included in Yukon Energy's LNG feasibility and planning work.

The participants were asked to report on the following questions:

1. **What should the transition plans look like (transition from diesel to LNG and then from LNG to renewable source)?**

    a. How do we link renewable options to LNG? What do we need to avoid during the transition to LNG that would block or slow down the future transition to renewable sources?
    b. What is an acceptable length of time for the transition period and what is an acceptable length of time before transitioning back to renewable sources?
    c. How do we transition off LNG so it does not become the default energy source if Yukon Energy's objective is to produce electricity from renewable sources?

2. **Discuss a strategy for moving forward with LNG in Yukon.**

    a. What information and resources are needed?
    b. What does Yukon Energy need to do?
    c. What does Yukon Government need to do?
    d. What do First Nation Governments need to do?
    e. What does industry need to do?
    f. Who are the other stakeholders and what do they need to do?

6. Results

The following is a summary from the workshop and public meeting.

<u>Transition Planning</u>

<u>Transition from Diesel to LNG Should:</u>

- Involve a strategy based not only on economics but also on affordability, reliability, flexibility, and environmental responsibility;
- Consider a review of the entire Yukon energy system and all future energy demands;
- Involve an energy demand management program;
- Focus on local sources of LNG that will be subject to local environmental regulations, and may be cheaper and have lower environmental impacts because of shorter transportation distances;
- Consider how LNG can be integrated gradually into the existing system;
- Begin with a larger off-grid mining project that could function as an "anchor tenant"; and
- Work to develop the LNG infrastructure and market simultaneously.

Potential Barriers to the Transition from LNG to Renewable Sources Include:

- Low cost of LNG will make the move to renewable options look complicated, time consuming and expensive;
- Unforeseen industrial and residential development will require the continued use of fossil fuels;
- The cost of the transition from diesel to LNG will deplete funding for the transition to renewable sources;
- Bringing renewable options to off-grid communities and industrial users will remain difficult and expensive (especially once LNG is in place);
- Inertia may come with the development of an LNG distribution network and other users such as residential heating and powering vehicles;
- Incentives to develop LNG are in place across North America; and
- The industrial sector may not be willing to contribute to capital costs for renewable projects if they can produce energy cheaply on-site using LNG.

The LNG to Renewable Sources Transition Plan Should:

- Set firm benchmarks, timelines, and targets for renewable sources before LNG is put in place;
- Include transition timelines based on realistic estimates for the development of renewable projects;
- Consider using savings from the LNG to diesel transition to finance renewable projects:
- Consider funding renewable projects through feed-in tariffs, a method of offering cost-based compensation to renewable energy producers;
- Plan for a future that will involve a mix of energy sources, including LNG, with a gradually increasing share of renewable sources;
- Consider the potential of hydrogen assisted renewables , such as the HARP (Hydrogen Assisted Renewable Power project in Bella Coola), and bioenergy to add flexibility to the system;
- Evaluate options for connecting to the BC power grid to make capital-intensive hydro projects worth while;
- Work with new industrial users to develop small scale renewable projects;
- Consider focussing on renewable options for the base energy load while continuing to use LNG for shorter term industrial uses;
- Ensure that the future transition to renewables does not lead to uncertainty in terms of energy costs or availability; and
- Begin working now on renewable options as large capital projects may take a long time to develop.

Strategy for Moving Forward with LNG

Information and Resources Needed:

- An understanding of future energy needs both on and off grid and the seasonal and annual variation in both potential loads and current hydro capacity;
- Consideration of the most efficient location for LNG energy generation facility;
- Evaluation of the potential supply sources of LNG and potential economic and environmental differences between these sources;
- A full economic analysis including the initial investment required, pay back period, local markets, and potential risks;
- An understanding of the potential players and partnerships;
- An understanding of the current and future regulatory environment;
- Results from the ATCO LNG pilot project currently underway in Watson Lake;
- Options for retrofitting existing generators and equipment to use LNG;
- Information about options such as dual fuel systems and combined cycles using exhaust heat;
- Consideration of other potential markets for LNG such as residential heating, mining machinery, and vehicles;
- A comparison of GHG emissions associated with diesel and LNG;
- An understanding of the full environmental impacts and life cycle costs of switching to LNG; and
- Consideration of potential grants, tax cuts, subsidies, or public-private partnerships that could be used to help develop required LNG infrastructure.

Yukon Energy Needs to:

- Work closely with the Yukon Government and other potential partners including the City of Whitehorse, First Nations, customers, the public, fuel providers, and industry in Alaska, British Columbia, and NWT;
- Develop a plan for LNG that can be implemented in stages and that balances industrial and residential customers, as well as on-grid and off-grid users;
- Develop a credible business plan that considers life-cycle costing, the capital investments required, and the potential market;
- Understand the regulatory environment;
- Ensure that costs to customers will not increase;
- Use the waste heat for district heating;
- Focus on bringing LNG first to communities, First Nations, or off-grid industrial users that are ready now;
- Develop a culture of energy efficiency and conservation;
- Finalize partnerships and commit to moving forward with LNG;
- Consider focussing on residential energy needs, with options to sell surpluses to mines when available; and

- Develop and implement a public education plan focussed on the benefits and impacts, trade-offs, and potential costs of the transition to LNG.

Yukon Government Needs to:

- Develop regulations that are based on full cradle-to-grave impacts, with a consideration of the best practices from other jurisdictions;
- Understand Yukon's natural gas resources and the potential benefits and impacts of development;
- Bring together a project team including representatives from the federal government;
- Ensure that regulatory staff get sufficient technical training;
- Foster effective leadership and work towards buy-in from politicians and managers;
- Work with and encourage the private sector;
- Understand the implications of international trade agreements;
- Evaluate options for subsidies or public-private partnerships to get LNG infrastructure started; and
- Set high ethical, environmental, and safety standards for LNG operations in Yukon.

Industry Needs to:

- Ensure that there is a firm commitment from customers and a stable market before investing in LNG infrastructure projects;
- Consider all types of potential partnerships;
- Train employees in LNG facilities and operations;
- Carry their fair share of the risk associated with transition to LNG; and
- Consider opportunities for mines in the same area to share LNG resources.

First Nations Need to:

- Consider opportunities to access low or no-interest loans for LNG infrastructure; and
- Explore the full range of potential partnerships.

7. Summary

The workshop participants and the public recognize that LNG has the potential to be a good near-term transitional energy source for Yukon between current diesel use and future renewable options. LNG costs less and has lower air emissions than diesel; it offers flexibility, and can be developed to meet forecasted loads by 2014 if planning began immediately. Natural gas for the liquefaction process can be sourced from currently available gas reserves in BC, however it was also noted that the development of Yukon gas could decrease transportation distances/costs, create local jobs, and the extraction methods would be subject to Yukon regulations.

Participants at the workshop have suggested that prior to moving forward with LNG, Yukon Energy develop a plan which includes a mix of renewable energy sources and clearly outlines

the transitional nature of LNG. This plan should include an implementation plan in the context of balancing the needs of industrial, residential, on-grid and off-grid customers. A long term commitment from large industrial users and Yukon Energy will be required before investments in LNG infrastructure are made. Yukon Energy will need to work closely with potential partners including the Yukon Government, City of Whitehorse, First Nations, rate payers and customers, fuel providers, and industry in Yukon BC, NWT and Alaska. Subsidies, incentives, and public private partnerships may be useful in getting LNG infrastructure projects underway.

There is concern that the transition from LNG to renewable energy sources will be difficult because compared to LNG, renewable options may look difficult, expensive, and have long development timelines. In order to ensure the timely transition to renewable energy sources, plans for renewable projects, and firm benchmarks, timelines, and targets for renewable sources need to be in place before work begins on LNG infrastructure. Connecting to the southern grid and using the financial savings of switching to LNG to fund future renewable sources should be considered.

Yukon Energy thanks all those that participated in the workshop and public meeting. The presentations from the workshop experts along with the responses to the workshop questions are being incorporated into Yukon Energy's evaluation of the LNG options. Yukon Energy is committed to working with its partners, sharing information and to keep talking.

TOPIC:

REFERENCE: December 9, 2013 Application, Figure 4-2 (page 41)

Source: U.S. Energy Information Administration; Annual Energy Outlook 2013

PREAMBLE:

With respect to the U.S. Energy Information Administration Annual Energy Outlook 2013:

QUESTION:

a) Please explain how the EIA's National Energy Modeling System develops the long-term projects of energy supply, demand, and prices through 2040.

b) Please confirm that the projections within the EIA's 2013 Annual Energy Outlook are based on federal, state, and local laws and regulations in effect in the United States as of the end of September 2012.

c) Please confirm that Figure 86 of the EIA's 2013 Annual Energy Outlook indicates that the annual average Henry Hub spot natural gas prices are expected to increase annually through the EIA's forecast period.

d) Please confirm that the reference in the EIA's 2013 Annual Energy Outlook that "fuel costs for LNG or CNG are expected to be well below the projected cost of diesel fuel on an energy-equivalent basis" (page 36) was in the context of LNG and CNG being used for transportation (i.e., heavy duty trucks).

e) Please provide a copy of the EIA's Annual Energy Outlook 2014 Early Release Overview.

f) Please confirm that for its 2014 outlook, the EIA has changed its estimating process for natural gas prices to the electricity generation sector to better reflect current market conditions in which many large natural gas consumers are outside the city gate.

g) Please provide the name and credentials of the witness that will be adopting the EIA's 2013 Annual Energy Outlook report as evidence and responding to cross-examination on its contents.

ANSWER:

(a) and **(b)**

The U.S. Energy Information Administration's (EIA) Annual Energy Outlook 2013 (AEO2013)[1] was published in April 2013. The Application reported at pages 40 and 41 on the forecast in this publication of world crude oil prices and natural gas prices.

As regards the approach adopted in AEO2013, the document notes that the U.S. natural gas prices are determined largely on a regional basis, in response to supply and demand conditions in North America[2]. AEO2013 projects that the net natural gas imports from Canada decline sharply from 2016 to 2022, then stabilize somewhat before dropping off again in the final years of the projection, as continued growth in domestic production mitigates the need for imports. The projections reflect laws and regulations in effect at the end of September 2012.

(c)

Confirmed. Figure 86 of AEO2013 shows that Henry Hub spot natural gas prices are expected to increase annually through the forecast period. It should be noted that oil prices are also expected to increase and Figure 87 of AEO2013 provides the ratio of Brent Crude Oil Price to Henry Hub Spot Natural Gas Price in Energy Equivalent Terms as reviewed in the Application[3].

(d)

The reference provided in the request is in the context of LNG and Compressed Natural Gas (CNG) as part of fuel switching in transportation, including heavy duty trucks, train, marine operations and others.

[1] http://www.eia.gov/forecasts/aeo/pdf/0383(2013).pdf

[2] AEO2013 notes that there was a shift from using regional natural gas wellhead prices (AEO 2012) to using representative regional natural gas spot prices as the basis of the natural gas supply price.

[3] Please see Figure 4-2 of the Part 3 Application.

(e)

Please see UCG-YEC-1-13(e) Attachment 1 for the copy of EIA's Annual Energy Outlook 2014 Early Release Overview[4].

(f)

Confirmed.

(g)

The Application at pages 40-41 references information contained in the US Energy Information Administration Report (Annual Energy Outlook 2013). This report was prepared by a statistical and analytical agency within the U.S. Department of Energy that collects, analyzes, and disseminates independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding of energy and its interaction with the economy and the environment[5].

Neither Yukon Energy nor its consultants prepared the report and cannot testify as to the details of how the report was prepared; however, the panel will be prepared to defend the Application as presented and can speak to their understanding of the report's contents as reflected in the Application.

[4] Source: http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2014).pdf.
[5] http://www.eia.gov/about/mission_overview.cfm

AEO2014 Early Release Overview

Executive summary

Projections in the *Annual Energy Outlook 2014 (AEO2014)* Reference case focus on the factors that shape U.S. energy markets through 2040, under the assumption that current laws and regulations remain generally unchanged throughout the projection period. The early release provides a basis for the examination and discussion of energy market trends and serves as a starting point for analysis of potential changes in U.S. energy policies, rules, or regulations or possible technology breakthroughs. Readers are encouraged to review the full range of cases that will be presented when the complete *AEO2014* is released in 2014, exploring key uncertainties in the Reference case.

Major highlights of the *AEO2014* Reference case include:

Growing domestic production of natural gas and crude oil continues to reshape the U.S. energy economy, with crude oil production approaching the historical high achieved in 1970 of 9.6 million barrels per day

Ongoing improvements in advanced technologies for crude oil and natural gas production continue to lift domestic supply and reshape the U.S. energy economy. Domestic production of crude oil (including lease condensate) increases sharply in the *AEO2014* Reference case, with annual growth averaging 0.8 million barrels per day (MMbbl/d) through 2016, when it totals 9.5 MMbbl/d (Figure 1). While domestic crude oil production is expected to level off and then slowly decline after 2020 in the Reference case, natural gas production grows steadily, with a 56% increase between 2012 and 2040, when production reaches 37.6 trillion cubic feet (Tcf).The full *AEO2014* will include cases that represent alternative oil and natural gas resource and technology assumptions.

Low natural gas prices boost natural gas-intensive industries

Industrial shipments grow at a 3.0% annual rate over the first 10 years of the projection and then slow to 1.6% annual growth for the rest of the projection. Bulk chemicals and metals-based durables account for much of the increased growth in industrial shipments in *AEO2014*. Industrial shipments of bulk chemicals, which benefit from an increased supply of natural gas liquids, grow by 3.4% per year from 2012 to 2025 in *AEO2014*, as compared with 1.9% in the *Annual Energy Outlook 2013 (AEO2013)* Reference case. The projection assumes growing competition from abroad that flattens output growth in energy-intensive industries after 2030.

The higher level of industrial shipments leads to more natural gas consumption (including lease and plant fuel) in the U.S. industrial sector, increasing from 8.7 quadrillion British thermal units (Btu) in 2012 to 10.6 quadrillion Btu in 2025 in *AEO2014*, compared to 9.8 quadrillion Btu in 2025 in *AEO2013*.

Light-duty vehicle energy use declines sharply, reflecting slow growth in vehicle miles traveled and accelerated improvement in vehicle efficiency

AEO2014 includes a new, detailed demographic profile of driving behavior by age and gender as well as new lower population growth rates based on updated U.S. Census Bureau projections. As a result, annual increases in vehicle miles traveled (VMT) for light-duty vehicles (LDVs) in the *AEO2014* Reference case average 0.9% from 2012 to 2040, compared to 1.2% per year in *AEO2013* over the same period. The rising fuel economy of LDVs more than offsets the modest growth in VMT, and LDV energy consumption declines in the *AEO2014* Reference case from 16.0 quadrillion Btu in 2012 to 12.1 quadrillion Btu in 2040, as compared with the *AEO2013* total of 13.0 quadrillion Btu in 2040 (Figure 2). The full *AEO2014* will include an Issues in Focus discussion of VMT projections that addresses the implications of alternative VMT scenarios.

Figure 1. U.S. petroleum and other liquid fuels supply by source, 1970-2040 (million barrels per day)

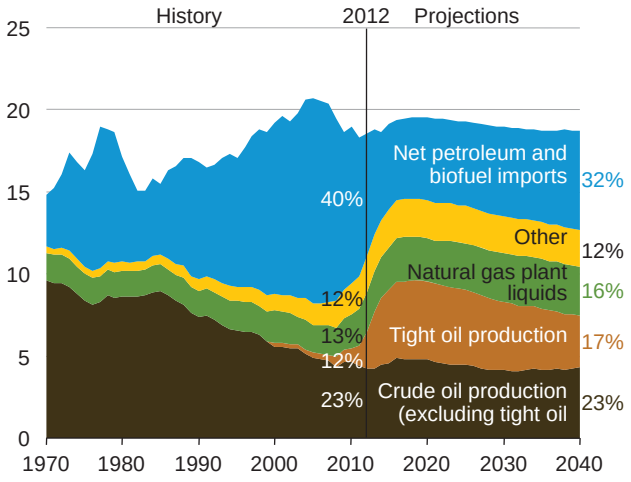
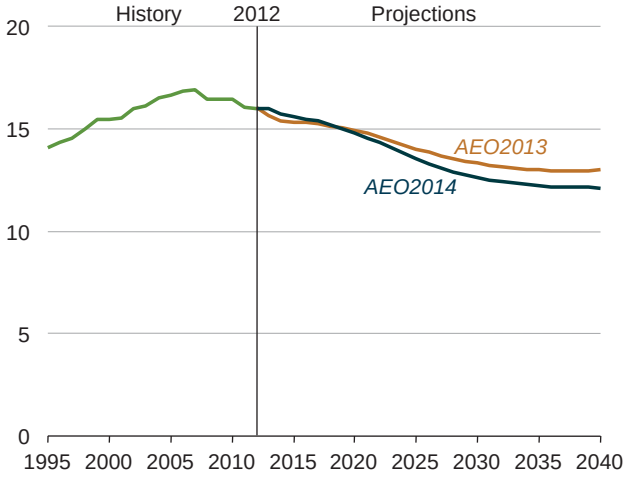


Figure 2. Energy consumption by light-duty vehicles in the United States, *AEO2013* and *AEO2014*, 1995-2040 (quadrillion Btu)



Natural gas overtakes coal to provide the largest share of U.S. electric power generation

Projected low prices for natural gas make it a very attractive fuel for new generating capacity. In some areas, natural gas-fired generation replaces generation formerly supplied by coal and nuclear plants. In 2040, natural gas accounts for 35% of total electricity generation, while coal accounts for 32% (Figure 3). Generation from renewable fuels, unlike coal and nuclear power, is higher in the *AEO2014* Reference case than in *AEO2013*. Electric power generation with renewables is bolstered by legislation enacted at the beginning of 2013 extending tax credits for various renewable technologies; which was passed after the *AEO2013* Reference case had been completed, but was considered in an alternative case in *AEO2013*. The full *AEO2014* will include a variety of cases addressing the implications of alternative market conditions and policies for the electricity generation mix.

Higher natural gas production also supports increases in exports of both pipeline and liquefied natural gas

In addition to increases in domestic consumption in the industrial and electric power sectors, U.S. exports of natural gas also increase in the *AEO2014* Reference case (Figure 4). U.S. exports of liquefied natural gas (LNG) increase to 3.5 Tcf in 2029 and remain at that level through 2040. Pipeline exports of U.S. natural gas to Mexico grow by 6% per year, from 0.6 Tcf in 2012 to 3.1 Tcf in 2040, and pipeline exports to Canada grow by 1.2% per year, from 1.0 Tcf in 2012 to 1.4 Tcf in 2040. Over the same period, U.S. pipeline imports from Canada fall by 30%, from 3.0 Tcf in 2012 to 2.1 Tcf in 2040, as more U.S. demand is met by domestic production. Projected exports are sensitive to assumptions regarding conditions in U.S. and global natural gas markets. The full *AEO2014* will include cases that illustrate the sensitivity of projected natural gas exports to alternative resource, economic, and price scenarios.

With strong growth in domestic crude oil and natural gas production, U.S. use of imported fuels falls sharply

In the *AEO2014* Reference case, U.S. domestic energy production increases from 79.1 quadrillion Btu in 2012 to 102.1 quadrillion Btu in 2040, and net use of imported energy sources, which was 30% in 2005, falls from 16% of total consumption in 2012 to 4% in 2040. In the *AEO2013* Reference case, domestic energy production reached a total of 98.5 quadrillion Btu, and energy imports is projected to decline as a percentage of consumption to 9% in 2040. The larger increase in domestic energy production in *AEO2014* is primarily a result of higher projections of production of natural gas and biomass/other renewables. Crude oil production (including lease condensate) increases from 13.9 quadrillion Btu in 2012 to a peak of 20.5 quadrillion Btu in 2019 before dropping to 16.0 quadrillion Btu in 2040.

With domestic crude oil production rising to 9.5 MMbbl/d in 2016, the import share of U.S. petroleum and other liquids supply falls to about 25%. Domestic production begins to decline after 2019, and the import share of total petroleum and other liquids supply grows to 32% in 2040, still lower than the 2040 level of 37% in the *AEO2013* Reference case. The alternative cases in the full *AEO2014* will illustrate how different assumptions about resources, markets, and policies can dramatically impact projections of import dependence.

Improved efficiency of energy use in the residential and transportation sectors and a shift away from carbon-intensive fuels for electricity generation keep U.S. energy-related carbon dioxide emissions below their 2005 level through 2040

In the *AEO2014* Reference case, total U.S. energy-related emissions of carbon dioxide (CO_2) remain below the 2005 level in every year through 2040. Projected emissions in 2020 and 2040 are, respectively, about 9% and 7% below the 2005 level.

In *AEO2014*, CO_2 emissions associated with U.S. industrial activity (including CO_2 emissions associated with the generation of electricity used in the industrial sector) begin to surpass emissions from the transportation sector in the middle of the next

Figure 3. Electricity generation from natural gas and coal, 2005-2040 (billion kilowatthours)

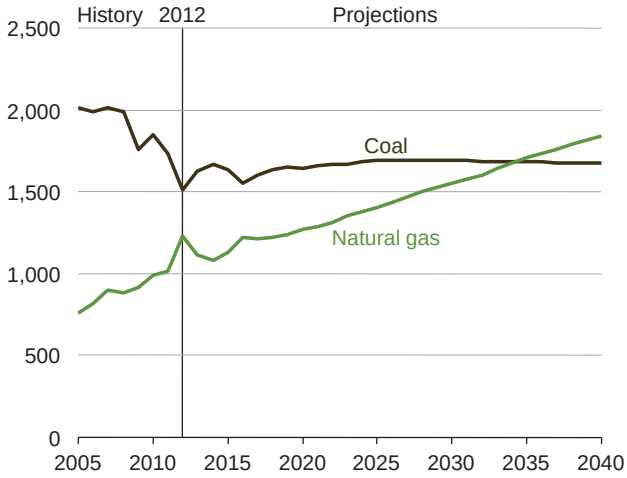
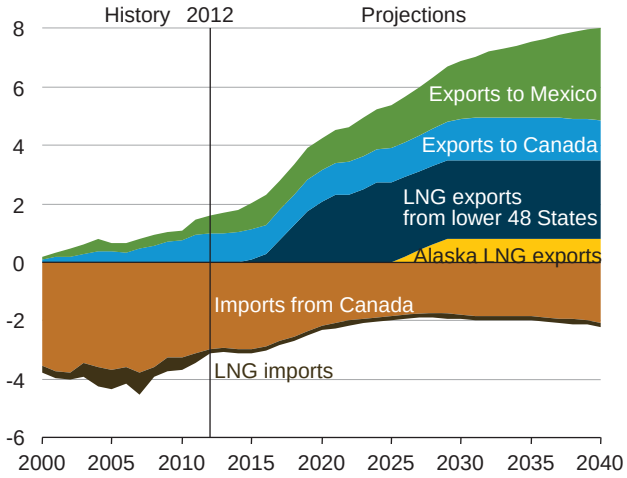


Figure 4. U.S. natural gas imports and exports, 2000-40 (trillion cubic feet)



decade for the first time since the late 1990s. In the transportation sector, as a result of new fuel economy standards, biofuel mandates, and shifts in consumer behavior, emissions from transportation sector use of petroleum and other liquids generally decline or remain stable from 2012 through 2040. Emissions from energy use in the commercial sector increase more rapidly than in the residential sector, and in 2040 emissions from these two sectors are about equal. In the electric power sector, CO_2 emissions from coal combustion decline after 2029 as more power plants are fueled by lower-carbon fuels, including natural gas and renewables. However, the lower level of CO_2 emissions in the electric power sector because of the reduced role for coal is partially offset by less projected generation from nuclear power. Generation from nuclear power in *AEO2014* is 10% below levels in *AEO2013* in 2040 as a result of increased nuclear plant retirements.

Projected growth in real gross domestic product is slightly slower than in AEO2013, but projected per capita GDP and disposable income are higher than in AEO2013 because of a reduced projection for U.S. population growth

Annual growth of real gross domestic product (GDP) from 2012 to 2040 averages 2.4% in the *AEO2014* Reference case, slightly below the *AEO2013* Reference case growth rate over the same period. However, industrial output growth is higher in *AEO2014*, averaging 2.1% per year from 2012 to 2040. Industries that supply equipment for increased natural gas production, as well as industries benefitting from lower natural gas prices, account for much of the higher growth in manufacturing. On a per capita basis, projected annual growth rates for real GDP and disposable income in *AEO2014*, both averaging 1.7% per year, are above the comparable rates in *AEO2013*, reflecting lower projected population growth rate estimates (0.7% in *AEO2014* compared to 0.9% in *AEO2013)* for the 2012-40 period provided by the U.S. Census Bureau.

Introduction

In preparing the *AEO2014* Reference case, the U.S. Energy Information Administration (EIA) evaluated a wide range of trends and issues that could have major implications for U.S. energy markets. This overview presents the *AEO2014* Reference case and compares it with the *AEO2013* Reference case released in April 2013 (see Table 1 on pages 17-18). Because of the uncertainties inherent in any energy market projection, the Reference case results should not be viewed in isolation. Readers are encouraged to review the alternative cases when the complete *AEO2014* publication is released, to gain perspective on how variations in key assumptions can lead to different outlooks for energy markets.

To provide a basis against which alternative cases and policies can be compared, the *AEO2014* Reference case generally assumes that current laws and regulations affecting the energy sector remain unchanged throughout the projection (including the implication that laws that include sunset dates do, in fact, expire at the time of those sunset dates). This assumption clarifies the relationship of the Reference case to other *AEO2014* cases and enables policy analysis with less uncertainty regarding unstated legal or regulatory assumptions.

As in past editions, the complete *AEO2014* will include additional cases, many of which reflect the effects of extending a variety of current energy programs beyond their current expiration dates and the permanent retention of a broad set of programs that currently are subject to sunset provisions. In addition to the alternative cases prepared for *AEO2014*, EIA has examined proposed policies at the request of Congress over the past few years. Reports describing the results of those analyses are available on EIA's website.[1]

Key updates made for the *AEO2014* Reference case include the following:

Macroeconomic

- Revised U.S. Census Bureau population projections.[2] The population projection for 2040 in the *AEO2014* Reference case is almost 6% below the 2040 projection used for the *AEO2013* Reference case. Most of the revision in overall population growth results from a lower projection for net international migration, with younger age groups showing the largest differences from the earlier projection. The slower rate of population growth leads to less labor force growth, which contributes to slower GDP growth.

Residential, commercial, and industrial

- Revised base year residential equipment stocks and energy consumption for space heating, space cooling, and water heating, based on data from EIA's 2009 Residential Energy Consumption Survey (RECS), the most recent data available.[3] Estimates of appliance stocks and energy consumption for several miscellaneous electric loads also were updated, based on a report by Navigant Consulting Inc., to better reflect recent changes and trends in the residential sector.[4]

[1]See "Congressional & Other Requests," http://www.eia.gov/analysis/reports.cfm?t=138.
[2]The new population projections were released on December 12, 2012. See U.S. Department of Commerce, "U.S. Census Bureau Projections Show a Slower Growing, Older, More Diverse Nation a Half Century from Now" (Washington, DC: December 12, 2012), http://www.census.gov/newsroom/releases/archives/population/cb12-243.html.
[3]U.S. Energy Information Administration, "Residential Energy Consumption Survey (RECS): 2009 RECS Survey Data, Public Use Microdata File (Washington, DC: January 2013), http://www.eia.gov/consumption/residential/data/2009/index.cfm?view=microdata.
[4]Navigant Consulting, Inc., *Analysis and Representation of Miscellaneous Electric Loads in the National Energy Modeling System (NEMS)* (Washington, DC: May 2013), prepared for the U.S. Department of Energy, U.S. Energy Information Administration.

- Updated and expanded representation of miscellaneous electric loads in the commercial sector, as well as personal computers and data center servers, based on the Navigant report, reflecting recent and expected trends in electronics use.[5]
- Updated costs and improved representation of residential lighting applications, including wider representation of light emitting diode (LED) lighting and outdoor lighting, based on the 2009 RECS and two U.S. Department of Energy (DOE) reports.[6, 7]
- Revised handling of the regional efficiency standard for residential furnaces, based on an ongoing legal appeal of the standard. The regional standard scheduled to take effect in 2013 is not included in *AEO2014* because of a court challenge and proposed settlement that would vacate the standard in question and require DOE to develop new residential furnace standards.
- Revised commercial capacity factors governing annual usage of major end-use equipment, based on an EIA-contracted analysis.
- Updated manufacturing sector data to reflect the 2010 Manufacturing Energy Consumption Survey (MECS).[8]
- Revised outlook for industrial production to reflect the effects of increased shale gas production and lower natural gas prices, resulting in faster growth for industrial production and energy consumption. The industries primarily affected include energy-intensive bulk chemicals and primary metals, both of which provide products used by the mining and other downstream industries such as fabricated metals and machinery. The bulk chemicals industry is also a major user of natural gas and, increasingly, hydrocarbon gas liquid (HGL) feedstocks.[9]
- Expanded process flow models for the cement and lime industry and the aluminum industry, allowing technologies based on energy efficiency to be incorporated, as well as enhancement of the cement model to include renewable fuels.

Transportation

- Implemented a new approach to VMT projections for LDVs, based on an analysis of VMT by age cohorts and the aging of the driving population over the course of the projection, which resulted in a significantly lower level of VMT growth after 2018 compared with *AEO2013*. On balance, demographic trends (such as an aging population and decreasing rates of licensing and travel among younger age groups) combine with employment and income factors to produce a 30% increase in VMT from 2012 to 2040 in *AEO2014* compared with 41% growth in *AEO2013*.
- Added LNG as a potential fuel choice for freight rail locomotives and domestic marine vessels, resulting in significant penetration of natural gas as a fuel for freight rail (35% of freight rail energy consumption in 2040) but relatively minor penetration in domestic marine vessels (2% of domestic marine energy consumption in 2040).
- Adopted a new approach for estimating freight travel demand by region and commodity for heavy-duty vehicles (HDVs), rail, and domestic marine vessels, as well as updated fuel efficiencies for freight rail and domestic marine vessels.
- Updated handling of flex-fuel vehicle (FFV) fuel shares to better reflect consumer preferences and industry response. FFVs are necessary to meet the renewable fuels standard (RFS), but the phase-out of corporate average fuel economy (CAFE) credits for their sale, as well as limited demand from consumers, reduces their market penetration.
- Revised attributes for battery electric vehicles—including (1) product availability, (2) electric drive fuel efficiency, and (3) non-battery system costs by vehicle size class, battery size, and added battery cost per kilowatthour based on vehicle power-to-energy ratio for vehicle type—applied to hybrid electric, plug-in hybrid electric, and all-electric vehicles.

Oil and natural gas production and product markets

- Revised network pricing assumptions based on benchmarking of regional natural gas hub prices to historical spot natural gas prices, basing flow decisions on spot prices, setting variable tariffs based on historical spot natural gas price differentials, and estimating the price of natural gas to the electric power sector off a netback from the regional hub prices.[10]

[5]Navigant Consulting, Inc., *Analysis and Representation of Miscellaneous Electric Loads in the National Energy Modeling System (NEMS)* (Washington, DC: May 2013), prepared for the U.S. Department of Energy, U.S. Energy Information Administration.

[6]U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, *Residential Lighting End-Use Consumption Study: Estimation Framework and Initial Estimates* (Washington, DC: December 2012), http://apps1.eere.energy.gov/buildings/publications/pdfs/ssl/2012_residential-lighting-study.pdf.

[7]U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, *2010 U.S. Lighting Market Characterization* (Washington, DC: January 2012), http://apps1.eere.energy.gov/buildings/publications/pdfs/ssl/2010-lmc-final-jan-2012.pdf.

[8]U.S. Energy Information Administration, "Manufacturing Energy Consumption Survey (MECS): 2010 MECS Survey Data" (Washington, DC: March 19, 2013), http://www.eia.gov/consumption/manufacturing/data/2010/.

[9]Growing production of wet natural gas and lighter crude oil has focused attention on natural gas liquids (NGL). EIA has developed and adopted a neutral term—"hydrocarbon gas liquid" (HGL)—to equate the supply (natural gas plant liquids [NGPL] + liquefied refinery gases [LRG]) and market (NGL + refinery olefins) terms. For example, liquefied petroleum gas (LPG) is currently defined by EIA as ethane, propane, normal butane, and isobutane and their olefins (ethylene, propylene, butylene, and isobutylene). This definition is inconsistent with definitions used by other federal agencies, international organizations, and trade groups, in that it implies that all the products are in a liquid state (ethane typically is not) and are used in the same way (higher-value olefins are used differently). Part of the HGL implementation redefines LPG to include only propane, butane, and isobutane and to exclude ethane and refinery olefins. The tables included in *AEO2014* have been relabeled to conform to this newly adopted definition.

[10]Estimating natural gas prices to the electricity generation sector based on hub prices, rather than the citygate prices as was done in prior years, is a better reflection of current market conditions, in which many large natural gas consumers are outside the citygate.

- Allowed secondary flows of natural gas out of the Middle Atlantic region to change dynamically in the model based on relative prices, which enables a larger volume of natural gas from the Middle Atlantic's Marcellus formation to supply neighboring regions.
- Developed the estimated ultimate recovery of tight oil and shale gas on the basis of county-level data.[11]
- Updated oil and gas supply module that explicitly reports technically recoverable resources of liquids in natural gas, enabling estimation of dry and wet natural gas.
- Improved representation of the dynamics of U.S. gasoline and diesel exports versus U.S. demand, through adoption of endogenous modeling.[12]
- Added representation of the U.S. crude oil distribution system (pipelines, marine, and rail), to allow crude oil imports to go to logical import regions for transport to refineries, which enables crude imports and domestic production to move among refining regions and keeps imports of Canadian crude oil from flowing directly to U.S. Gulf refiners.[13]
- Revised production outlook for nonpetroleum other liquids—gas-to-liquids, coal-to-liquids (CTL), biomass-to-liquids, and pyrolysis[14]—with lower production levels than in *AEO2013*, as more recent experience with these emerging technologies indicates higher costs than previously assumed.[15]
- Revised representation of CO_2-enhanced oil recovery (EOR) that better integrates the electricity, oil and gas supply, and refining modules.[16]

Electric power sector

- Revised approach to reserve margins, which are set by region on the basis of North American Electric Reliability Corporation/Independent System Operator requirements,[17] and capacity payments, which are calculated as a combination of levelized costs for combustion turbines and the marginal value of capacity in the electricity model.
- Revised handling of spinning reserves, with the required levels set explicitly depending on the mix of generating technologies used to meet peak demand by region, to allow better representation of capacity requirements and costs in regions or cases with high penetration of intermittent loads.
- Revised assumptions concerning the potential for unannounced retirement of nuclear capacity in several regions to better reflect the impact of rising operating costs and low electricity prices. Announced nuclear retirements are already incorporated as planned.
- Updated handling of Mercury and Air Toxics Standards (MATS)[18] covering the electric power sector to reflect potential upgrades of electrostatic precipitators, requirements for plants with dry scrubbers to employ fabric filters, and revised costs for retrofits of dry sorbent injection and fabric filters.
- Updated treatment of the production tax credit (PTC) for eligible renewable electricity generation technologies—consistent with the American Taxpayer Relief Act of 2012 (ATRA) passed in January 2013[19]—including revision of PTC expiration dates for each PTC-eligible technology to reflect the concept of projects being declared "under construction" as opposed to being placed "in service" and extension of the expiration date of the PTC for wind generation projects by one year.

Economic growth

Macroeconomic projections in the *Annual Energy Outlook (AEO)* are trend projections, with no major shocks assumed and with potential growth determined by the economy's supply capability. Growth in aggregate supply depends on increases in the labor force, growth of capital stocks, and improvements in productivity. Long-term demand growth depends on labor force growth,

[11]After accounting for infrastructure constraints and general development patterns, oil and natural gas resources in "sweet spots" are developed earlier than lower quality resources, based on net present value.

[12]High U.S. crude oil production and low fuel costs have given U.S. refiners a competitive advantage over foreign refiners, as evidenced by high U.S. refinery utilization and increasing U.S. exports of gasoline and diesel fuel.

[13]Oil imports from Canada now are required to go to Petroleum Administration for Defense District (PADD) 2 (Midwest: North Dakota, South Dakota, Nebraska, Kansas, Oklahoma, Minnesota, Iowa, Missouri, Wisconsin, Illinois, Michigan, Indiana, Ohio, Kentucky, and Tennessee); PADD 4 (Rocky Mountain: Montana, Idaho, Wyoming, Utah, and Colorado); and PADD 5 (West Coast: Washington, Oregon, Nevada, California, Arizona, Alaska, and Hawaii) for redistribution through the crude oil distribution infrastructure.

[14]Pyrolysis is defined as the thermal decomposition of biomass at high temperatures (greater than 400°F, or 200°C) in the absence of air.

[15]EIA undertook detailed assessments of these technologies in order to characterize key parameters considered in the model, such as capital cost, contingency factors, construction time, first year of operation, plant life, plant production capacity, efficiency, and feedstock and other operating costs.

[16]When considering CO_2 EOR, the oil and gas supply module assesses a location and the availability and price of CO_2 from power plants and CTL facilities. The electric power plants now consider the market size and prices for CO_2 captured. The refining module assesses a location and the availability and price of CO_2 from CTL facilities. The power sector now assesses opportunities for plants equipped with carbon capture and storage, as the CO_2 produced at these facilities can be used for EOR operations. This enables the model to solve dynamically for the capture of CO_2 and the production of oil from anthropogenic CO_2 EOR.

[17]North American Electric Reliability Corporation, *2013 Summer Reliability Assessment* (Atlanta, GA: May 2013), http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2013SRA_Final.pdf.

[18]U.S. Environmental Protection Agency, "Mercury and Air Toxics Standards (MATS)," http://www.epa.gov/mats.

[19]U.S. House of Representatives, 112th Congress, Public Law 112-240, "American Taxpayer Relief Act of 2012," Sections 401-412 (Washington, DC: January 2, 2013), http://www.gpo.gov/fdsys/pkg/PLAW-112publ240/pdf/PLAW-112publ240.pdf.

income growth, and population growth. *AEO2014* uses the U.S. Census Bureau's December 2012 middle population projection. The U.S. Census Bureau revised its population projections primarily to reflect lower assumptions regarding international net migration.

In *AEO2014*, U.S. population is expected to grow at an annual rate of 0.7% from 2012 to 2040, or 0.2 percentage points lower than the 0.9% average annual population growth rate in *AEO2013*. As shown in Figure 5, most of the change from *AEO2013* to *AEO2014* is in the younger age cohorts. Real GDP, labor force, and productivity in *AEO2014* grow by average annual rates of 2.4%, 0.6%, and 1.8%, respectively, from 2012 to 2040.

Total industrial production growth (which includes manufacturing, construction, agriculture, and mining) in *AEO2014* is higher than projected in *AEO2013*, primarily as a result of more rapid growth in manufacturing output, with most of the difference accounted for by machinery, transportation equipment, fabricated metals, and bulk chemicals. Those industries, in addition to being trade-sensitive, supply equipment or raw materials used in oil and gas production or otherwise benefit from lower natural gas prices. In 2040, the manufacturing share of total gross output is 18% in *AEO2014*, compared with 16% in *AEO2013*.

Energy prices

Crude oil

Oil prices are influenced by several factors, including some that have mainly short-term impacts. Other factors, such as expectations about future world demand for petroleum and other liquids and production decisions by the Organization of the Petroleum Exporting Countries (OPEC), can affect prices over the longer term. Supply and demand in the world oil market are balanced through responses to price movements, with considerable complexity in the evolution of underlying supply and demand expectations. For petroleum and other liquids, the key determinants of long-term supply and prices can be summarized in four broad categories: the economics of non-OPEC supply; OPEC investment and production decisions; the economics of other liquids supply; and world demand for petroleum and other liquids.

Key assumptions driving global crude oil markets in the *AEO2014* Reference case over the projection period include: average economic growth of 1.9% per year for major U.S. trading partners[20] and average economic growth of 4.0% per year for other U.S. trading partners. Growth in petroleum and other liquids use occurs almost exclusively outside the Organization for Economic Cooperation and Development (OECD) member countries, with 1.8% average annual growth in petroleum and other liquids consumption by non-OECD countries, including significantly higher average annual consumption growth in both China and India.

Petroleum and other liquids production in *AEO2014* from non-OPEC countries, particularly the United States, increases to levels above those in *AEO2013*. As a result, the OPEC market share declines to less than 40% in the near term before starting to rise again after 2016. The Brent crude oil spot price decreases from $112 per barrel (bbl) in 2012 to $92/bbl in 2017 in the Reference case (in 2012 dollars), then increases to $141/bbl in 2040 (or about $235/bbl in nominal dollars) as growing demand leads to the development of more costly resources (Figure 6). However, those resources are not as costly to develop as projected in *AEO2013*.

Figure 5. Comparisons of population growth by projection period and age cohort in the *AEO2014* and *AEO2013* Reference cases (*AEO2014* growth minus *AEO2013* growth)

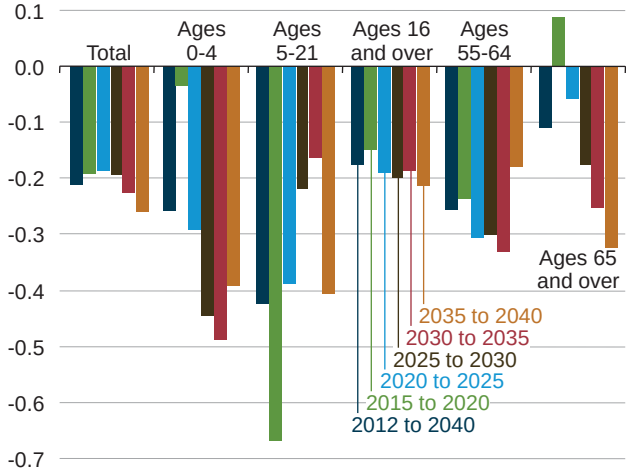
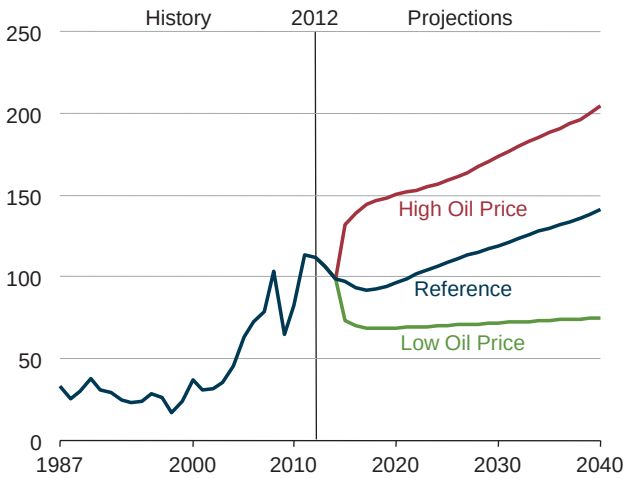


Figure 6. Average annual Brent spot crude oil prices in three cases, 1987-2040 (2012 dollars per barrel)



[20]Major trading partners include Australia, Canada, Switzerland, United Kingdom, Japan, Sweden, and the Eurozone.

Petroleum and other liquids products

With lower crude oil prices and lower gasoline demand projected in the *AEO2014* Reference case, the real end-use price of motor gasoline in the United States declines to $3.03 per gallon (2012 dollars) in 2017, then rises to $3.90 per gallon in 2040 (compared to $4.40 per gallon in 2040 in *AEO2013*). The end-use price of diesel fuel in the transportation sector follows a similar pattern, dropping to $3.50 per gallon in 2017 and then rising to $4.73 per gallon in 2040 (compared to $5.03 per gallon in *AEO2013*). Although both gasoline and diesel prices dip modestly in the early years of the projection period, they increase steadily thereafter. The diesel share of total domestic petroleum and other liquids production rises, and the gasoline share falls, mostly as a result of the greenhouse gas (GHG) and CAFE standards for LDVs beginning in model year 2017. Increasing demand for diesel puts pressure on refiners to increase diesel yields and results in a rising difference between diesel prices and gasoline prices from 2017 to 2025.

Legislated targets for cellulosic fuels use mandated by the Energy Independence and Security Act of 2007 (EISA2007) are not attained, as the U.S. Environmental Protection Agency (EPA)[21] continues to make use of the flexibility provided in the statute to adjust those requirements.

Natural gas

The Henry Hub spot price for natural gas in the *AEO2014* Reference case is higher than projected in *AEO2013* through 2037, with price increases in the near term driven by faster growth of consumption in the industrial and electric power sectors and, later, growing demand for export at LNG facilities. A sustained increase in production follows, leading to slower price growth over the rest of the projection period.

The Henry Hub spot natural gas price in *AEO2014* reaches $4.80 per million Btu (MMBtu) (2012 dollars) in 2018, which is 77 cents/MMBtu higher than in *AEO2013*. The stronger near-term price growth is followed by a lagged increase in supply from producers, eventually causing prices to settle at $4.38/MMBtu in 2020, which is still notably higher than in *AEO2013*.

After 2020, increases in natural gas spot prices are driven by continued but slower growth in U.S. demand and net exports. The Henry Hub spot natural gas price rises to $7.65/MMBtu in 2040, an increase of $3.28 from 2020 but 4% below the 2040 price projection in *AEO2013*. In *AEO2014*, production grows to 37.5 Tcf in 2040, compared with 33.1 Tcf in *AEO2013*. A price increase starting in 2033 is far less pronounced than was projected in *AEO2013*, in part because the growth in net exports from the United States slows significantly.

Regional spot price projections throughout the United States follow the same general pattern as the Henry Hub spot price. However, the average Lower 48 spot price generally increases at a slightly slower rate than the Henry Hub spot price, because regional production growth outside those areas that serve the Henry Hub is projected to be somewhat faster than the growth in production that serves the Henry Hub.

Coal

The average minemouth price of coal increases by 1.4% per year in the *AEO2014* Reference case, from $1.98/MMBtu in 2012 to $2.96/MMBtu in 2040 (2012 dollars). The upward trend of coal prices primarily reflects an expectation that cost savings from technological improvements in coal mining will be outweighed by increases in production costs associated with moving into reserves that are more costly to mine. The upward trend in the minemouth price of coal in the *AEO2014* Reference case is similar to the trend in the *AEO2013* Reference case, but the average price through the projection period in *AEO2014* is generally lower, primarily reflecting a lower price outlook for coking coal.

Relative to minemouth prices, the average delivered price of coal to all sectors (excluding exports) increases at a slightly slower pace of 1.0% per year, from $2.60/MMBtu in 2012 to $3.43/MMBtu in 2040. The slower growth rate primarily reflects modest growth in average coal transportation rates, which increase by 0.2% per year in *AEO2014*—from $0.83/MMBtu in 2012 to $0.89/MMBtu in 2040—as a result of gradually increasing fuel costs and changes over time in the pattern of coal distribution.

U.S. coal exports, which have surged in recent years from 50 million short tons in 2005 to a record 126 million short tons (MMst) in 2012, have become an increasingly important source of revenue for both U.S. coal producers and coal transportation companies (primarily railroads and barge companies). In 2012, coal export revenues totaled about $15 billion, representing about 25% of all U.S. coal revenues, despite the fact that coal exports in 2012 represented only 12% of total U.S. production (short tons). In the *AEO2014* Reference case, U.S. coal export prices increase by 1.2% per year, to $6.40/MMBtu in 2040.

Electricity

Following the decline of natural gas prices since 2008, real average delivered prices for electricity have dropped consistently (although more gradually) since 2009, to 9.8 cents per kilowatthour (kWh) in 2012. Retail electricity prices are influenced by fuel prices, and particularly by natural gas prices. However, the relationship between retail electricity prices and natural gas prices is complex, and many factors influence the degree to which, and the timeframe over which, they are linked. Those factors include the share of natural gas generation in a region, the level of costs associated with the electricity transmission and distribution systems,

[21] U.S. Environmental Protection Agency, "2014 Standards for the Renewable Fuel Standard Program: Proposed Rule," 40 CFR Part 80 [EPA-HQ-OAR-2013-0479; FRL-9900-90-OAR], RIN 2060-AR76, *Federal Register,* Vol. 78, No. 230 (Washington, DC: November 29, 2013), pp. 71732-71784, http://www.gpo.gov/fdsys/pkg/FR-2013-11-29/pdf/2013-28155.pdf.

the mix of competitive versus cost-of-service pricing, and the number of customers who purchase power directly from wholesale power markets. As a result, it can take time for changes in fuel prices to affect electricity prices, and the impacts can vary from region to region.

In the *AEO2014* Reference case, electricity prices are higher throughout the projection than they were in the *AEO2013* Reference case. Natural gas prices for electricity generators are higher than those in *AEO2013* in the first few years but fairly similar in the long term. Reliance on natural gas-fired generation remains strong, as a result of additional near-term retirements of coal-fired and nuclear capacity, and natural gas prices continue to influence electricity prices. In the long term, both natural gas prices and electricity prices rise. Electricity prices, which in 2030 are 10.4 cents/kWh (2012 dollars) in the *AEO2014* Reference case, compared with 9.9 cents/kWh in the *AEO2013* Reference case, continue rising to 11.1 cents/kWh in 2040 in *AEO2014*, compared with 11.0 cents/kWh in the *AEO2013* Reference case.

The *AEO2014* Reference case includes an updated calculation of electricity prices in competitive regions that better represents payments required to maintain reserve capacity, contributing to higher projected electricity prices relative to *AEO2013*. In addition, the updated regional reserve margin requirements in *AEO2014* generally are higher and thus more costly than those in *AEO2013*.

Delivered energy consumption by sector[22]

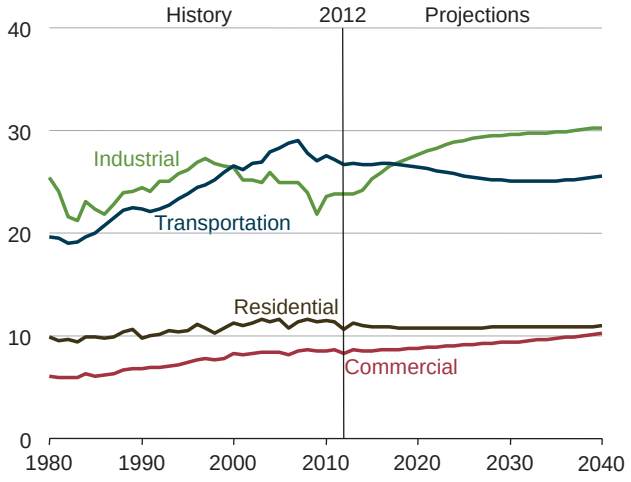
Transportation

Delivered energy consumption in the transportation sector declines from 26.7 quadrillion Btu in 2012 to 25.5 quadrillion Btu in 2040 in the *AEO2014* Reference case (Figure 7) because of a significant decline in energy consumption by LDVs that more than offsets growth in energy consumption for other modes. The decline in transportation sector delivered energy consumption is markedly different from the historical trend of 1% average annual growth in transportation energy consumption from 1975 to 2012.[23] Transportation energy consumption is considerably lower in *AEO2014* than projected in the *AEO2013* Reference case (27.1 quadrillion Btu in 2040) with energy consumption by nearly all transportation modes reduced in *AEO2014* as a result of lower macroeconomic indicators, higher energy efficiency, changing demographics, and a revised calculation of VMT.

LDV energy consumption declines in the *AEO2014* Reference case from 16.0 quadrillion Btu in 2012 to 12.1 quadrillion Btu in 2040, compared with 13.0 quadrillion Btu in 2040 in the *AEO2013* Reference case. GHG emission standards and CAFE standards increase new LDV fuel economy through model year 2025 and beyond, with more fuel-efficient new vehicles gradually replacing older vehicles on the road and raising the fuel efficiency of the LDV stock by an average of 2.0% per year, from 21.5 miles per gallon (mpg) in 2012 to 37.2 mpg in 2040. The higher fuel economy of LDVs more than offsets increases in VMT that average 0.9% per year from 2012 to 2040, a reduction from the *AEO2013* projection that reflects changes in driving behavior related to changing demographics. The average fuel economy of the vehicle stock is higher, and travel by LDVs is lower in *AEO2014* than projected in *AEO2013*. The large decline in LDV energy consumption in *AEO2014* shrinks the LDV modal share of total transportation energy consumption from 60% in 2012 to 47% in 2040.

LDVs powered by motor gasoline remain the dominant vehicle type in the *AEO2014* Reference case, retaining a 78% share of new LDV sales in 2040, down from their 82% share in 2012. The fuel economy of LDVs powered by motor gasoline continues to increase, and advanced technology fuel efficiency subsystems are added, such as micro hybridization, which is installed on 42% of new motor gasoline LDVs in 2040. The numbers of LDVs powered by fuels other than gasoline, such as diesel, electricity, or E85, or equipped with hybrid drive trains, such as plug-in hybrid or gasoline hybrid electric, increase modestly from 18% of new sales in 2012 to 22% in 2040. Ethanol FFVs account for 11% of overall vehicle sales in 2040, followed by hybrid electric vehicles (excluding micro hybrids) at 5% of new sales in 2040, up from 3% in 2012, diesel vehicles at 4% in 2040, up from 2% in 2012, and plug-in hybrid vehicles and electric vehicles at about 1% each, both up from negligible shares in 2012. New vehicle sales shares are generally similar in *AEO2014* and *AEO2013* but with moderate variation. In *AEO2013*, the new vehicle sales share of motor gasoline vehicles was 80% in 2040 (with 36% of those vehicles including micro hybridization), followed by 7% for ethanol FFVs, 6% for hybrid electric, 3% for diesel, 2% for plug-in hybrids, and 1% for electric vehicles. The differences from *AEO2013* to *AEO2014* result from different fuel prices,

Figure 7. Delivered energy consumption by sector, 1980-2040 (quadrillion Btu)



[22]The amount of energy delivered to the sector; no adjustment is made for the fuels consumed to produce electricity or district sources.

[23]S.C. Davis, S.W. Diegel, and R.G. Boundy, *Transportation Energy Data Book*, ORNL-6989 (Edition 32 of ORNL-5198) (Oak Ridge, TN: July 2013), Chapter 2, Table 2.1, "U.S. Consumption of Total Energy by End-Use Sector, 1973-2012."

updated manufacturer product offerings, changing technology attributes, and an updated view of consumer perceptions of infrastructure availability for E85 vehicles.

Delivered energy demand for HDVs in *AEO2014* increases from 5.3 quadrillion Btu in 2012 to 7.5 quadrillion Btu in 2040, similar to the 2040 level of 7.6 quadrillion Btu in *AEO2013,* and represents the largest growth among all transportation modes. Growth in industrial output in *AEO2014* leads to solid growth in HDV VMT, averaging 1.9% per year from 2012 to 2040. HDV energy demand is tempered somewhat by an average 0.5% annual increase in fuel economy from 2012 to 2040 as a result of GHG emission and fuel efficiency standards for medium- and heavy-duty vehicles and engines. Competitive natural gas prices significantly increase the demand for LNG and compressed natural gas in *AEO2014*, from an insignificant share in 2012 to 8% of HDV energy consumption in 2040, which is less than the 13% share projected in *AEO2013* because of the lower prices of competing fuels in *AEO2014*. The rapid growth of energy consumption by HDVs in *AEO2014* increases their modal share of total transportation energy consumption from 20% in 2012 to 29% in 2040.

Energy demand for aircraft grows in the *AEO2014* Reference case from 2.5 quadrillion Btu in 2012 to 2.7 quadrillion Btu in 2040, which is less than the *AEO2013* projection of 2.9 quadrillion Btu in 2040. Personal air travel (billion seat-miles) grows by an average of 0.7% per year in *AEO2014*, but improved fuel efficiency (by an average of 0.5% per year) reduces the effect on energy consumption. The difference between *AEO2014* and *AEO2013* stems from lower demand for personal air travel in *AEO2014* as a result of lower economic growth. The aircraft share of total transportation energy consumption in *AEO2014* increases from 9% in 2012 to 11% in 2040.

Energy consumption by marine vessels increases from 0.9 quadrillion Btu in 2012 to 1.0 quadrillion Btu in 2040 in *AEO2014*, reflecting the impacts of increased foreign trade on international shipping and higher incomes on recreational boating. Pipeline energy use rises modestly, from 0.7 quadrillion Btu in 2012 to 0.8 quadrillion Btu in 2040, as increasing volumes of natural gas are produced but closer to end-use markets. Rail energy consumption remains nearly flat at 0.5 quadrillion Btu from 2012 to 2040 in *AEO2014*, as a result of a plateau in coal shipments and increases in fuel efficiency, which offset growth in rail transportation of other industrial commodities.

Other energy use in the transportation sector, which includes both lubricants and military energy use, increases from 0.8 quadrillion Btu in 2012 to 0.9 quadrillion Btu in 2040. Marine, pipeline, other transportation, and rail energy use all are relatively minor pieces of the overall transportation energy consumption picture in *AEO2014*, each accounting for less energy demand than in the *AEO2013* projections, as a result of lower economic growth in the *AEO2014* Reference case.

Industrial

Approximately one-third of total U.S. delivered energy in 2012, 23.6 quadrillion Btu, was consumed in the industrial sector, which includes manufacturing, agriculture, construction, and mining. In the *AEO2014* Reference case, total industrial delivered energy consumption grows to 30.2 quadrillion Btu in 2040—1.5 quadrillion Btu, or 5%, higher than the *AEO2013* Reference case projection. The industrial sector becomes the largest energy consuming sector by 2018 and remains so for the rest of the projection period.

The growth rate for total industrial energy consumption in the *AEO2014* Reference case is greater than in *AEO2013* as a result of lower natural gas prices, which boost industrial production, and greater availability of natural gas liquids (NGL).[24] The industry that consumes the most energy is bulk chemicals, where total energy consumption grows from 5.5 quadrillion Btu in 2012 to 7.0 quadrillion Btu in 2040. In the *AEO2014* Reference case, energy consumption by the bulk chemicals industry in 2040 is 1.2 quadrillion Btu higher than projected in *AEO2013*.

Total manufacturing shipments in the *AEO2014* Reference case also increase more rapidly than in the *AEO2013* Reference case, from $4.5 trillion in 2012 to $8.4 trillion in 2040, or 87%. The growth rate for shipments in energy-intensive manufacturing is one-half the rate for non-energy-intensive manufacturing, reflecting the continuing shift toward less energy-intensive manufacturing, such as transportation equipment, computers, and other durable metal goods. The rate of growth in all manufacturing industries is higher from 2012 to 2025 than after 2025, as a result of increased international competition in the later years of the projection.

Shipments in the energy-intensive industries—refining, food, paper, bulk chemicals, glass, cement and lime, iron and steel, and aluminum—grow from $1.6 trillion in 2012 to $2.3 trillion in 2040 in the *AEO2014* Reference case, an annual rate of growth of 1.3%, compared to 1.0% in the *AEO2013* Reference case. The rate of increase in *AEO2014* is much faster from 2012 to 2025 (2.0% per year) than from 2025 to 2040 (0.7% per year). Shipments of bulk chemicals, iron and steel, and aluminum peak in the late 2020s and decline thereafter, as export growth slows. Total energy consumption in the energy-intensive industries increases by 0.7% per year from 2012 to 2040, with almost all the growth occurring in the 2012-25 period.

Energy use for heat and power in the energy-intensive industries grows from 11.5 quadrillion Btu in 2012 to 13.1 quadrillion Btu in 2040, averaging 0.9% per year from 2012 to 2025 and 0.1% per year from 2025 to 2040. With energy intensity declining in the energy-intensive industries, largely because of improvements in efficiency, the growth of energy use for heat and power is slower than the growth of shipments. In the bulk chemicals and petroleum refining industries, demand for feedstocks—which include HGL,[25] petroleum (usually naphtha), and natural gas—grows by 1.3% per year on average, from 3.5 quadrillion Btu in 2012 to 5.0

[24]Natural gas liquids include ethane, propane, normal butane, isobutane, and pentanes plus.
[25]HGL includes NGL, ethane, propane, normal butane, isobutane, natural gasoline (pentanes plus), and olefins.

quadrillion Btu in 2040, with average increases of 2.9% per year from 2012 to 2025 followed by a decline from 2025 to 2040 averaging 0.1% per year.

Only the bulk chemical industry uses liquid feedstocks (HGL and petrochemical feedstocks), which are used to produce organic chemicals, inorganic chemicals, resins, synthetic rubber, and fibers. With demand for bulk chemicals higher in the *AEO2014* Reference case than in *AEO2013*, consumption of liquid feedstocks also is higher in *AEO2014*. HGL feedstocks and petrochemical feedstocks (naphtha and heavier inputs) often can be interchanged to some degree, depending on price and the product slate. In the *AEO2014* Reference case, HGL feedstock consumption totals 2.2 quadrillion Btu in 2012, 2.9 quadrillion Btu in 2025, and 2.7 quadrilion Btu in 2040; and petrochemical feedstock use totals 0.8 quadrillion Btu in 2012, 1.5 quadrillion Btu in 2025, and 1.6 quadrillion Btu in 2040.

Shipments from the nonenergy-intensive manufacturing sector increase by 2.7% per year from $2.9 trillion in 2012 to $6.1 trillion in 2040 in the *AEO2014* Reference case, with growth rates of 3.2% per year from 2012 to 2025 and 2.3% per year after 2025. Energy consumption for nonenergy-intensive manufacturing grows from 3.6 quadrillion Btu in 2012 to 4.9 quadrillion Btu in 2040, averaging 1.0% per year—the same rate as in the *AEO2013* Reference case. In parallel with the growth of shipments, energy consumption in the nonenergy-intensive manufacturing sector grows more rapidly from 2012 to 2025 (1.3% per year) than from 2025 to 2040 (0.8% per year).

In the nonmanufacturing industries—agriculture, construction, and mining—shipments grow by 1.6% per year from 2012 to 2040 in the *AEO2014* Reference case, slightly less than the annual growth rate of 1.8% in the *AEO2013* Reference case over the same period. Growth in the *AEO2014* Reference case averages 2.8% per year from 2012 to 2025 and slows to 0.7% per year after 2025. Energy consumption by nonmanufacturing industries grows by 1.2% per year, from 4.8 quadrillion Btu in 2012 to 6.8 quadrillion Btu in 2040. While energy intensity declines somewhat in the agriculture and construction industries, it increases in the mining industry as exploration activities move over time to less desirable—and more energy-intensive—resources.

Residential

Residential delivered energy consumption remains roughly constant in the *AEO2014* Reference case from 2012 to 2040. However, consumption levels are lower than those in *AEO2013* for most fuels. In addition to lower population growth projections, the lower consumption levels in the *AEO2014* Reference case are explained in part by incorporation of the 2009 RECS data, which include characteristic information such as the mix of building types in each region of the country, equipment stocks, and appliance saturation levels, as well as energy consumption estimates for three major end uses—space heating, space cooling, and water heating. In addition, weather-related demand elasticities for heating and cooling also have been updated to better align *AEO* projections with those in EIA's *Short-Term Energy Outlook*.

The *AEO2014* Reference case removes the 2013 federal efficiency standard for condensing gas furnaces, based on challenges to the DOE rulemaking, first by an association of natural gas utilities and later by equipment distributors. Although natural gas use tends to be lower when the standard is included, consumption in the *AEO2014* Reference case (without the standard) is lower than in *AEO2013* (with the standard) through most of the projection period, largely because of changes in the end-use allocations from the 2009 RECS.

An EIA-contracted report[26] provides updated estimates of the installed stock and consumption of several miscellaneous electric loads, including televisions, computers, and related equipment. This update generally resulted in lower electricity consumption for these appliances than was projected in the *AEO2013* Reference case.

For *AEO2014*, outdoor lighting was added to the residential model as a separate application. In addition, cost and performance attributes for most residential lighting types were updated on the basis of EIA-contracted technology reports[27] and market studies from DOE.[28] Lower costs and wider availability of LEDs result in lower energy consumption after 2020 in *AEO2014* relative to *AEO2013*.

Commercial

Commercial sector delivered energy consumption grows from 8.3 quadrillion Btu in 2012 to 10.2 quadrillion Btu in 2040 in the *AEO2014* Reference case, similar to the *AEO2013* Reference case despite slower growth in the near term. Commercial electricity consumption increases by 0.8% per year from 2012 to 2040 in *AEO2014*, lower than the 1.0% average annual growth in commercial floorspace, in part because projected demand for cooling and lighting is lower than in *AEO2013*. Also, more rapid reductions in energy use for personal computers than previously estimated, largely because of a shift to more efficient portable devices, result in a projected 5.6% annual decline in electricity demand for commercial PC equipment in the *AEO2014* Reference case. Following

[26]Navigant Consulting, Inc., *Analysis and Representation of Miscellaneous Electric Loads in NEMS* (Washington, DC, May 2013), prepared for the U.S. Department of Energy, U.S. Energy Information Administration.

[27]U.S. Energy Information Administration, "Updated Buildings Sector Appliance and Equipment Costs and Efficiency" (Washington, DC: August 7, 2013), http://www.eia.gov/analysis/studies/buildings/equipcosts/.

[28]U.S. Department of Energy, Energy Efficiency & Renewable Energy, *Residential Lighting End-Use Consumption Study: Estimation Framework and Initial Estimates* (Washington, DC: December 2012), http://apps1.eere.energy.gov/buildings/publications/pdfs/ssl/2012_residential-lighting-study.pdf, and *2010 U.S. Lighting Market Characterization* (Washington, DC: January 2012), http://apps1.eere.energy.gov/buildings/publications/pdfs/ssl/2010-lmc-final-jan-2012.pdf.

slower-than-expected adoption of new data centers as a result of the recent recession, installations of new data center servers increase more in *AEO2014* than in *AEO2013*.

Growth of natural gas consumption in the commercial sector averages roughly 0.7% per year from 2012 to 2040, similar to the *AEO2013* Reference case.

Energy consumption by primary fuel

Total primary energy consumption grows by 12% in the *AEO2014* Reference case, from 95 quadrillion Btu in 2012 to 106 quadrillion Btu in 2040—1.3 quadrillion Btu less than in *AEO2013* (Figure 8). The fossil fuel share of energy consumption falls from 82% in 2012 to 80% in 2040, as consumption of petroleum-based liquid fuels declines, largely as a result of slower growth in VMT and increased vehicle efficiency.

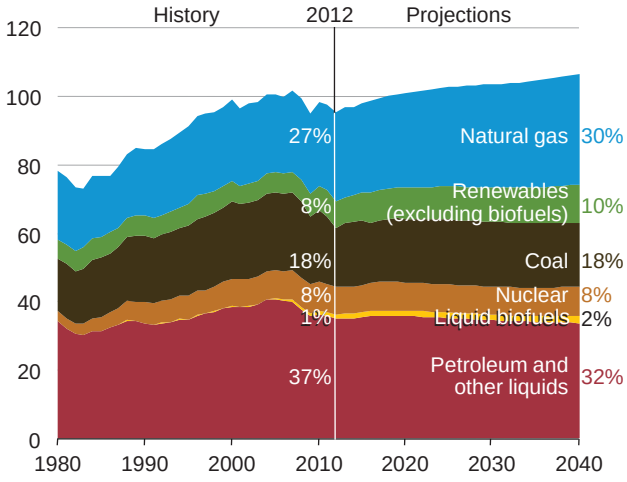
Total U.S. consumption of petroleum and other liquids, which was 35.9 quadrillion Btu (18.5 MMbbl/d) in 2012, increases to 36.9 quadrillion Btu (19.5 MMbbl/d) in 2018, then declines to 35.4 quadrillion Btu (18.7 MMbbl/d) in 2034 and remains at that level through 2040. Total consumption of domestically produced biofuels increases slightly through 2022 and then remains relatively flat. Production of cellulosic biofuels is currently well under 1% of the EISA2007 targets.[29] With the PTC for cellulosic biofuels scheduled to expire at the end of 2013, production of cellulosic biofuels remains below the EISA2007 target through the projection period. Within the transportation sector, which dominates demand for petroleum and other liquids, there is a shift from motor gasoline (losing more than 10% of its share of total transportation petroleum and other liquids demand over the projection) to distillate (gaining slightly less than 10% of the total). The increased use of compressed natural gas and LNG in vehicles also offsets about 3% of petroleum and other liquids consumption in the transportation sector in 2040.

Domestic natural gas consumption in the *AEO2014* Reference case rises from 25.6 Tcf in 2012 to 31.6 Tcf in 2040 (about 2.1 Tcf higher than in the *AEO2013* Reference case). The largest share of the growth is for electricity generation. Demand for natural gas in the electric power sector increases from 9.3 Tcf in 2012 to 11.2 Tcf in 2040, with a portion of the growth attributable to the retirement of 50 gigawatts of coal-fired capacity by 2021. Natural gas consumption in the industrial sector is also higher in *AEO2014* than was projected in *AEO2013*, as a result of the rejuvenation of the industrial sector as it benefits from surging shale gas production that is accompanied by slower growth of natural gas prices. Industries such as bulk chemicals, which use natural gas as a feedstock, are more strongly affected than others. In the residential sector, natural gas consumption declines throughout the projection.

Total coal consumption increases from 17.3 quadrillion Btu (891 MMst) in 2012 to 18.7 quadrillion Btu (979 MMst) in 2040 in the *AEO2014* Reference case. Coal consumption, mostly for electric power generation, falls off in 2016, the first year of the MATS. After 2016, coal-fired electricity generation increases slowly over the next 10 years as the remaining coal-fired capacity is used more intensively, but little capacity is added. Coal consumption in the electric power sector in 2040 is 17.3 quadrillion Btu (909 MMst) in the *AEO2014* Reference case. This level is about 1.4 quadrillion Btu (75 MMst) lower than in the *AEO2013* Reference case. No coal is consumed for CTL technology in the *AEO2014* Reference case.

With the implementation of the federal RFS for transportation fuels and state renewable portfolio standards for electricity generation, consumption of marketed renewable fuels grows by 1.4% per year in the *AEO2014* Reference case. Marketed renewable energy includes wood, municipal waste, other biomass, and hydroelectricity in the end-use sectors; hydroelectricity, geothermal, municipal solid waste, biomass, solar, and wind power in the electric power sector; and ethanol for gasoline blending and biomass-based diesel in the transportation sector, of which 1.5 quadrillion Btu is included with petroleum and other liquid fuels consumption in 2040. Excluding hydroelectricity, renewable energy consumption in the electric power sector grows from 1.9 quadrillion Btu in 2012 to 4.5 quadrillion Btu in 2040, with biomass accounting for 27% of the growth and wind 39%. Generation of electricity from solar photovoltaic energy shows the fastest growth, starting from a small base and accounting for 7.5% of total electricity generation from all nonhydropower renewable energy sources in 2040.

Figure 8. U.S. primary energy consumption by fuel, 1980-2040 (quadrillion Btu)



Energy intensity

From 1992 to 2012, energy use per dollar of GDP declined on average by 1.9% per year, in large part because of shifts within the economy from manufactured goods to the service sectors,

[29]Based on 2010, 2011, 2012, and 2013 evaluations of the volumes of cellulosic biofuels available, EPA substantially reduced the cellulosic biofuels obligation under the RFS for those years, with the 2013 obligation set at 6 million ethanol-equivalent gallons, less than 1% of the legislated target of 1 billion gallons.

which use relatively less energy per dollar of GDP. The dollar-value increase in the service sectors (in constant dollar terms) was almost 12 times the corresponding increase for the industrial sector over the same period. As a result, the share of total shipments accounted for by the industrial sector fell from 30% in 1992 to 22% in 2012 (including a slight increase from 2009 to 2012). In the *AEO2014* Reference case, the industrial share of total shipments increases to 24% in 2016, after which it declines again, at a very slow rate, to 23% in 2040. Energy use per 2005 dollar of GDP declines by 43% from 2012 to 2040 in *AEO2014* as the result of a continued shift from manufacturing to services (and, even within manufacturing, to less-energy-intensive manufacturing industries), rising energy prices, and the adoption of policies that promote energy efficiency.

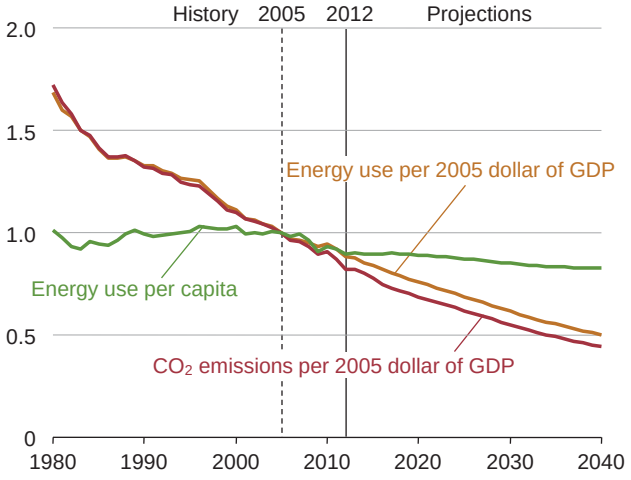
U.S. energy use per capita was fairly constant from 1990 to 2007 but began to fall after 2007. In the *AEO2014* Reference case, energy use per capita continues to decline as a result of improvements in energy efficiency (e.g., new appliance and CAFE standards) and changes in the ways energy is used in the U.S. economy. Total U.S. population increases by 21% from 2012 to 2040, but energy use grows by only 12%, with energy use per capita declining by 8% from 2012 to 2040 (Figure 9).

CO_2 emissions per 2005 dollar of GDP have historically tracked closely with energy use per dollar of GDP. In the *AEO2014* Reference case, however, with lower-carbon fuels accounting for a growing share of total energy use, CO_2 emissions per dollar of GDP decline more rapidly than energy use per dollar of GDP, to 56% below their 2005 level in 2040 (or by 2.3% per year).

Energy production and imports

Net imports of energy decline both in absolute terms and as a share of total U.S. energy consumption in the *AEO2014* Reference case (Figure 10). The decline in energy imports reflects increased domestic production of petroleum and natural gas, along with demand reductions resulting from rising energy prices and gradual improvement in vehicle efficiency. At the same time, natural gas exports increase (as domestic supplies increase and it becomes attractive to liquefy the natural gas for export), along with exports of motor gasoline (as demand declines and refiners are left with more than they can sell domestically) and exports of crude oil (as lighter domestic crude oil is swapped for the heavier crudes more commonly run in modern refineries). The net import share of total U.S. energy consumption is 4% in 2040, compared with 16% in 2012 and about 30% in 2005.

Figure 9. Energy use per capita, energy use per dollar of GDP, and emissions per dollar of GDP, 1980-2040 (index, 2005=1)



Petroleum and other liquids

U.S. production of crude oil (including lease condensate) in the *AEO2014* Reference case increases from 6.5 MMbbl/d in 2012 to 9.6 MMbbl/d in 2019, 22% higher than in *AEO2013* (Figure 11). Despite a decline after 2019, U.S. crude oil production remains at or above about 7.5 MMbbl/d through 2040. Higher production volumes result mainly from increased onshore oil production, predominantly from tight (very-low-permeability) formations. Offshore crude oil

Figure 10. Total energy production and consumption, 1980-2040 (quadrillion Btu)

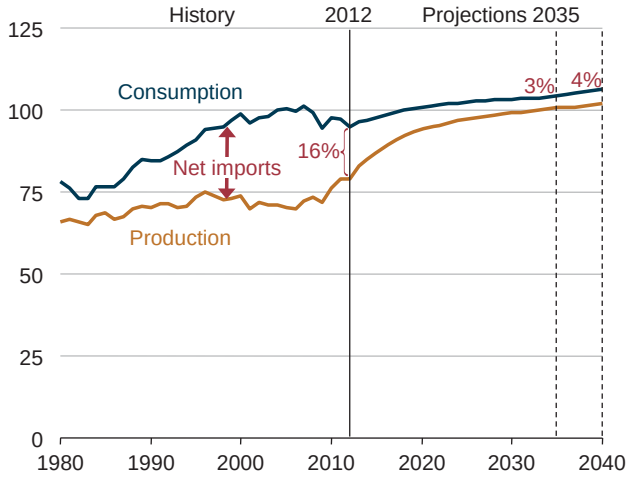
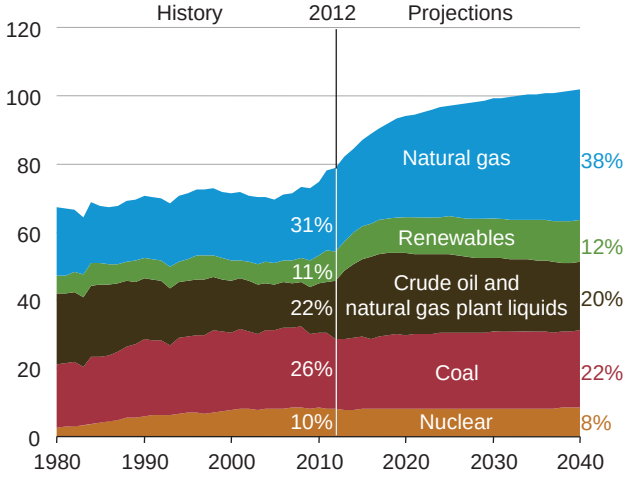


Figure 11. U.S. energy production by fuel, 1980-2040 (quadrillion Btu)



provides a steady supply of domestic crude oil production, ranging between 1.6 and 2.0 MMbbl/d from 2015 through 2040, as the pace of development activity quickens and new, large development projects, predominantly in the deepwater and ultra-deepwater portions of the Gulf of Mexico, are brought into production.

The faster growth of tight oil production through 2020 in the *AEO2014* Reference case results in higher domestic crude oil production than in *AEO2013* throughout the projection. The pace of oil-directed drilling in the near term is much stronger than in *AEO2013*, as producers locate and target the sweet spots of plays currently under development and find additional tight formations that can be developed with the latest technologies. In the *AEO2014* Reference case, tight oil production increases from 2.3 MMbbl/d in 2012 (35% of total U.S. crude oil production) to 4.8 MMbbl/d in 2021 (51% of the total). As in *AEO2013*, tight oil production declines in *AEO2014* after 2021, as more development moves into less-productive areas.

U.S. use of imported petroleum and other liquid fuels continues to decline in *AEO2014* mainly as a result of increased domestic oil production. Imported petroleum and other liquid fuels as a share of total U.S. use reached 60% in 2005 before dipping below 50% in 2010 and falling further to 40% in 2012. The import share continues to decline to 25% in 2016 and then rises to about 32% in 2040 in the *AEO2014* reference case, as domestic production of tight oil begins to decline in 2022 (Figure 12).

Natural gas

Cumulative production of dry natural gas from 2012 to 2040 in the *AEO2014* Reference case is about 11% higher than in *AEO2013*, primarily reflecting continued growth in shale gas production resulting from the dual application of horizontal drilling and hydraulic fracturing. Another contributing factor is ongoing drilling in shale and other plays with high concentrations of NGL and crude oil, which in energy-equivalent terms have a higher value than dry natural gas. Cumulative production levels for tight gas and onshore associated-dissolved gas from oil formations exceed those in *AEO2013* through 2040 by 9% and 36%, respectively, making material contributions to the overall increase in production. Natural gas prices above $6/MMBtu toward the end of the projection period encourage drilling in less-productive but still-profitable areas in tight oil, shale oil, and natural gas formations. Lower 48 offshore natural gas production fluctuates between 1.7 Tcf and 2.9 Tcf per year, similar to the pattern in *AEO2013*. The multiyear decline in offshore natural gas production was reversed in 2012, with 15 new deepwater projects coming on line during the year.

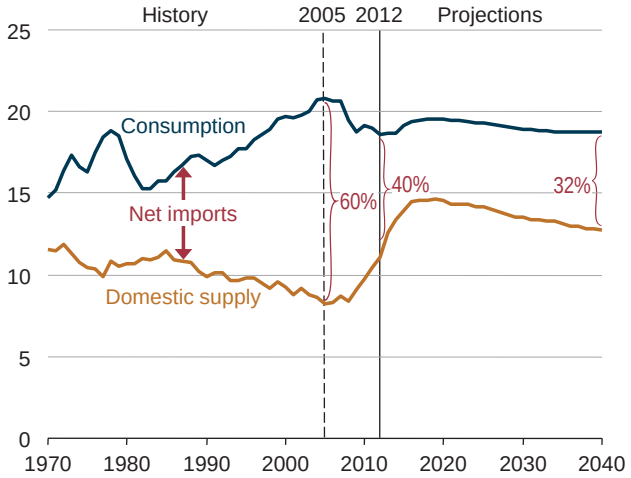
In the *AEO2014* Reference case, the United States becomes a net exporter of LNG in 2016, and it becomes an overall net exporter of natural gas in 2018, two years earlier than in *AEO2013*. U.S. exports of LNG from new liquefaction capacity are expected to surpass 2 Tcf by 2020 and increase to 3.5 Tcf in 2029. Net pipeline imports from Canada fall steadily until 2033, and then increase through 2040. Net pipeline exports to Mexico grow by more than 400% in the Reference case, with additional pipeline infrastructure added to enable the Mexican market to receive more pipeline natural gas from the United States.

U.S. cumulative net LNG exports from 2012 to 2040 are up by 160% in *AEO2014* compared with *AEO2013*, supported by increased use of LNG in markets outside America, strong domestic production, and low U.S. natural gas prices relative to other global markets.

Coal

Total U.S. coal production grows at an average rate of 0.3% per year in the *AEO2014* Reference case, from 20.6 quadrillion Btu (1,016 MMst) in 2012 to 22.6 quadrillion Btu (1,121 MMst) in 2040. U.S. electricity generation accounted for 91% of total U.S. coal consumption (in Btu) in 2012. Coal production declined by more than 7% in 2012, from 1,096 MMst in 2011, mostly in response to gas-on-coal competition. In the Reference case, production recovers to 1,062 MMst by 2015, in response to a rise in natural gas prices along with a moderate increase in electricity demand. A wave of coal-fired generating capacity retirements in response to MATS requirements coincides with a secondary drop in coal production to 1,022 MMst in 2016. Total production then increases gradually to 1,127 MMst in 2030 before stabilizing as a result of limits on achievable long-term capacity utilization rates for available coal units compared to *AEO2013*.

Figure 12. U.S. petroleum and other liquid fuels supply, 1970-2040 (million barrels per day)



Coal production from the Eastern Interior region in the *AEO2014* Reference case increases at a faster rate than projected in *AEO2013*, because of an improved productivity outlook, with 2020 production 27 MMst (18%) higher and 2040 production 58 MMst (34%) higher than projected in *AEO2013*. Lower overall coal consumption and improved competitiveness of coal produced in the Eastern Interior region compared to *AEO2013* lead to lower outlooks for Northern Appalachian and Powder River Basin coal production, as well as an accelerated decline in Central Appalachian production in *AEO2014*. As a result of changes to CTL cost assumptions, no CTL coal consumption or related production is projected in

AEO2014, compared with 0.3 quadrillion Btu in 2040 in *AEO2013*. Expectations for total U.S. coal exports in *AEO2014* are generally similar to those in *AEO2013*, with an increase from 126 MMst in 2012 to 161 MMst by 2040.

Electricity generation

Total electricity consumption in the *AEO2014* Reference case, including both purchases from electric power producers and on-site generation, grows from 3,826 billion kWh in 2012 to 4,954 billion kWh in 2040, an average annual rate of 0.9% that is about the same as in the *AEO2013* Reference case. While growth in electricity consumption is similar overall, growth in the industrial sector is much stronger than in *AEO2013*, while growth in the residential sector is weaker.

The combination of slow growth in electricity demand, competitively priced natural gas, programs encouraging renewable fuel use, and the implementation of environmental rules dampens future coal use. The *AEO2014* Reference case continues to assume implementation of the Clean Air Interstate Rule (CAIR)[30] as a result of an August 2012 federal court move to vacate the Cross-State Air Pollution Rule.[31] In addition, *AEO2014* continues to assume the implementation of MATS in 2016. Once MATS is in place, sulfur dioxide levels are reduced to well below the levels required by CAIR, and mercury emissions drop to 6.1 tons in 2016 from 30.8 tons in 2011 when the rule was finalized.

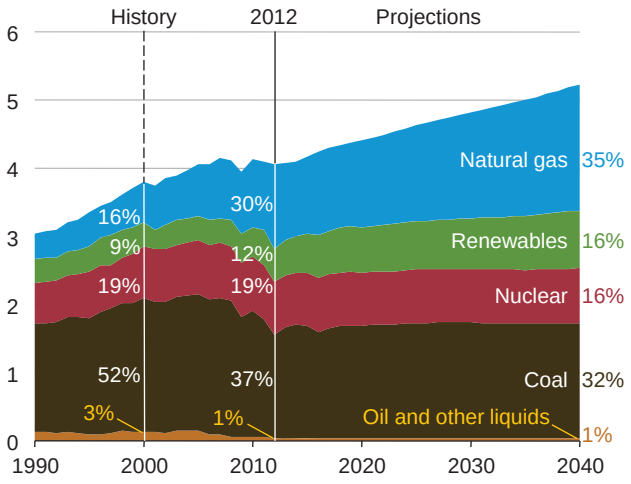
Coal-fired power generation over the next few years is slightly higher in *AEO2014* than in the *AEO2013* Reference case because of higher natural gas prices during that period, as well as pending nuclear retirements that necessitate additional baseload generation. After 2020, generation from coal flattens out and remains lower than projected in *AEO2013*, because more coal-fired capacity is retired and fewer new coal plants are built (Figure 13).

Coal-fired electricity generation has traditionally been the largest component of electricity generation, representing 37% of total generation in 2012. By 2035, however, natural gas generation is projected to surpass coal generation. Coal and natural gas each represent 34% of total generation in 2035, but by 2040 the coal share drops to 32%, and the natural gas share increases to 35%. Market concerns about GHG emissions continue to dampen the expansion of coal-fired capacity in the *AEO2014* Reference case, even with the assumption of current laws and policies. Low fuel prices for new natural gas-fired plants also affect the relative economics of coal-fired capacity, as does the continued rise in construction costs for new coal-fired power plants. As retirements far outpace new additions, total coal-fired generating capacity falls from 310 gigawatts (GW) in 2012 to 262 GW in 2040 in the *AEO2014* Reference case. As with all projections, projected generation shares are highly sensitive to both fuel prices and changes in policies and regulations. Alternative cases in the full *AEO2014* will quantify these sensitivities.

In the first few years of the projection, electricity generation using natural gas is slightly lower in the *AEO2014* Reference case than in the *AEO2013* Reference case because of higher natural gas prices in *AEO2014*. By 2017, however, natural gas-fired generation is higher in *AEO2014* than in the *AEO2013* Reference case, and the difference continues to grow. Additional retirements of coal and nuclear plants result in the need for new capacity, and new natural gas-fired plants are much cheaper to build than coal, nuclear, or renewable plants. In 2020, natural gas-fired generation in *AEO2014* is 7% higher than in *AEO2013*, and in 2040 it is 16% higher.

Electricity generation from nuclear power plants grows by 5% in the *AEO2014* Reference case, from 769 billion kWh in 2012 to 811 billion kWh in 2040, accounting for about 16% of total generation in 2040 (compared with 19% in 2012). Nuclear generating capacity decreases from 102 GW in 2012 to 98 GW in 2020 as new construction (5.5 GW) and uprates at existing plants (0.7 GW) are more than offset by retirements in several regions where existing nuclear units are facing challenging economic conditions. After 2025, a small amount of new nuclear capacity comes on line as natural gas prices rise. In 2040, overall nuclear capacity is back up to 102 GW. *AEO2014* incorporates updated information from EIA data collections regarding planned nuclear plant construction and capacity uprates at existing units.

Figure 13. Electricity generation by fuel, 1990-2040 (trillion kilowatthours)



Increased generation with renewable energy, excluding hydropower, accounts for 28% of the overall growth in electricity generation from 2012 to 2040 in the *AEO2014* Reference case. Generation from renewable resources grows in response to federal tax credits, state-level policies, and federal requirements to use more biomass-based transportation fuels, some of which can produce electricity as a byproduct of their production processes. In the final decade of the projection, however, renewable generation growth is driven by increasing cost competiveness with other nonrenewable technologies.

[30]U.S. Environmental Protection Agency, "Clean Air Interstate Rule (CAIR)" (Washington, DC: December 19, 2012), http://www.epa.gov/cair/.
[31]U.S. Environmental Protection Agency, "Fact Sheet: The Cross-State Air Pollution Rule: Reducing the Interstate Transport of Fine Particulate Matter and Ozone" (Washington, DC: July 2011), http://www.epa.gov/airtransport/pdfs/CSAPRFactsheet.pdf.

Compared to the *AEO2013* Reference case, renewable generation is higher throughout most of the projection period, particularly in the near term, because of the inclusion of the energy provisions of the ATRA. This law, among other things, extends several tax credits for utility-scale renewables and redefines the qualification criteria, resulting in more construction of wind-powered generating capacity in the near term.

Reported renewable capacity already under construction has increased in recent years and is represented in *AEO2014*. Growth in renewable generation is supported by many state requirements, as well as regulations on CO_2 emissions in California. The share of U.S. electricity generation coming from renewable fuels (including conventional hydropower) grows from 12% in 2012 to 16% in 2040 in the *AEO2014* Reference case, even with federal subsidies for renewable generation assumed to expire as enacted. Extensions of such subsidies could have a large impact on renewable generation. The long-run projections for renewable capacity are also sensitive to natural gas prices and the relative costs of alternative generation sources.

Energy-related CO_2 emissions

In the *AEO2014* Reference case, total U.S. energy-related CO_2 emissions in 2040 equal 5,599 million metric tons, 92 million metric tons (1.6%) lower than in *AEO2013*. However, the carbon intensity of the economy in 2040 is slightly (0.6%) higher in *AEO2014* as compared with *AEO2013*. Projected energy-related CO_2 emissions in 2020 and 2040 are, respectively, about 9% and 7% below the 2005 level, compared to 9% and 5% below the 2005 level in *AEO2013*.

The lower GDP projection in *AEO2014* is partly the result of a lower population growth rate, and GDP per capita in 2040 is almost 4% higher in *AEO2014* than in *AEO2013*. Energy use per capita and energy-related CO_2 emissions per capita are higher in *AEO2014* than in *AEO2013* (about 5% in 2040). Also, higher levels of energy consumption and CO_2 emissions per dollar of GDP in *AEO2014* occur with a sectoral shift in the share of energy consumption from the residential, commercial, and transportation sectors toward the industrial sector, which generally is more energy- and carbon-intensive than other sectors of the economy. Over the projection period from 2012 to 2040, industrial emissions grow at an average annual rate of 0.6% in *AEO2014*, and industrial energy-related CO_2 emissions in 2040 are 133 million metric tons higher in *AEO2014* than in *AEO2013*.

When examining the electric power sector, excluding combined heat and power, there are offsetting factors in comparing *AEO2014* and *AEO2013*. Coal use for generation is 7.9% lower in 2040 (141 billion kWh) in *AEO2014* compared to *AEO2013* as a result of increased retirements of coal capacity and replacement with natural gas and renewables. However, nuclear generation, which has no CO_2 emissions, is also 10.1% (91 billion kWh) lower in 2040 in *AEO2014* compared to *AEO2013* because of more nuclear retirements in *AEO2014*. This offsets the CO_2 reduction achieved by switching from coal to natural gas and renewables. In total, the carbon intensity of the electric power sector is lower in *AEO2014* as generation declines by 0.2% (9 billion kWh), but emissions are 1.9% lower in 2040.

List of Acronyms

AEO	*Annual Energy Outlook*
AEO2013	*Annual Energy Outlook 2013*
AEO2014	*Annual Energy Outlook 2014*
ATRA	American Taxpayer Relief Act of 2012
bbl	Barrels
Btu	British thermal units
CAFE	Corporate average fuel economy
CAIR	Clean Air Interstate Rule
CO_2	Carbon dioxide
CTL	Coal-to-liquids
DOE	U.S. Department of Energy
E85	Motor fuel containing up to 85% ethanol
EIA	U.S. Energy Information Administration
EISA2007	Energy Independence and Security Act of 2007
EOR	Enhanced oil recovery
EPA	U.S. Environmental Protection Agency
FFV	Flexible fuel vehicle
GDP	Gross domestic product
GHG	Greenhouse gas
GW	Gigawatts
HDV	Heavy-duty vehicle
HGL	Hydrocarbon gas liquid
kWh	Kilowatthour
LDV	Light-duty vehicle
LED	Light emitting diode
LNG	Liquefied natural gas
LPG	Liquefied petroleum gases
LRG	Liquefied refinery gases
MATS	Mercury and Air Toxics Standards
MECS	Manufacturing Energy Consumption Survey
MMbbl/d	Million barrels per day
MMBtu	Million Btu
MMst	Million short tons
NEMS	National Energy Modeling System
NGL	Natural gas liquids
NGPL	Natural gas plant liquids
OECD	Organization for Economic Cooperation and Development
OPEC	Organization of the Petroleum Exporting Countries
PADD	Petroleum Administration for Defense District
PTC	Production tax credit
RECS	Residential Energy Consumption Survey
RFS	Renewable fuel standard
Tcf	Trillion cubic feet
VMT	Vehicle-miles traveled

Table 1. Comparison of projections in the *AEO2014* and *AEO2013* Reference cases, 2011-2040

			2025		2040	
Energy and economic factors	2011	2012	*AEO2014*	*AEO2013*	*AEO2014*	*AEO2013*
Primary energy production (quadrillion Btu)						
Crude oil and natural gas plant liquids	15.31	17.08	23.03	18.70	19.99	17.01
Dry natural gas	23.04	24.59	32.57	29.22	38.37	33.87
Coal	22.22	20.60	22.36	22.54	22.61	23.54
Nuclear/Uranium	8.26	8.05	8.15	9.54	8.49	9.44
Hydropower	3.11	2.67	2.84	2.86	2.90	2.92
Biomass	3.90	3.78	5.08	5.27	5.61	6.96
Other renewable energy	1.70	1.97	3.09	2.32	3.89	3.84
Other	0.80	0.41	0.24	0.85	0.24	0.89
Total	**78.35**	**79.15**	**97.36**	**91.29**	**102.09**	**98.46**
Net imports (quadrillion Btu)						
Petroleum and other liquid fuels[a]	18.78	16.55	11.41	15.89	13.65	15.99
Natural gas (- indicates exports)	2.03	1.58	-3.41	-1.56	-5.81	-3.55
Coal/other (- indicates exports)	-2.32	-2.86	-3.16	-3.02	-3.69	-2.95
Total	**18.49**	**15.26**	**4.85**	**11.31**	**4.15**	**9.49**
Energy consumption by fuel (quadrillion Btu)						
Petroleum and other liquid fuels[a]	36.56	35.87	36.28	36.87	35.35	36.07
Natural gas	24.91	26.20	28.97	27.28	32.32	29.83
Coal	19.62	17.34	19.03	19.35	18.75	20.35
Nuclear/Uranium	8.26	8.05	8.15	9.54	8.49	9.44
Hydropower	3.11	2.67	2.84	2.86	2.90	2.92
Biomass	2.60	2.53	3.74	3.82	4.26	4.91
Other renewable energy	1.70	1.97	3.09	2.32	3.89	3.84
Other	0.35	0.39	0.35	0.30	0.35	0.29
Total	**97.11**	**95.02**	**102.45**	**102.34**	**106.31**	**107.64**
Energy consumption by sector, including losses in electricity generation (quadrillion Btu)[b]						
Residential	21.39	20.10	20.58	21.08	21.48	23.08
Commercial	18.05	17.61	18.77	19.04	20.88	21.13
Industrial	30.46	30.54	37.43	35.46	38.33	36.16
Transportation	27.21	26.77	25.67	26.75	25.62	27.27
Total	**97.11**	**95.02**	**102.45**	**102.34**	**106.31**	**107.64**
Petroleum and other liquid fuels (million barrels per day)						
Domestic crude oil production	5.66	6.49	9.00	6.79	7.48	6.13
Other domestic production	4.71	4.60	5.14	5.63	5.22	5.83
Net imports	8.57	7.50	5.12	7.08	6.02	7.00
Consumption	18.92	18.49	19.27	19.50	18.73	18.95
Natural gas (trillion cubic feet)						
Dry gas production + supplemental gas	22.61	24.12	31.93	28.65	37.61	33.21
Net imports (- indicates exports)	1.96	1.51	-3.41	-1.58	-5.80	-3.55
Consumption	24.38	25.64	28.35	26.87	31.63	29.54

Table 1. Comparison of projections in the *AEO2014* and *AEO2013* Reference cases, 2011-2040 (continued)

			2025		2040	
Energy and economic factors	2011	2012	*AEO2014*	*AEO2013*	*AEO2014*	*AEO2013*
Coal (million short tons)						
Production and waste coal	1,109	1,027	1,128	1,134	1,139	1,195
Net exports	96	118	135	124	160	123
Consumption	1,003	891	993	1,010	979	1,071
Prices (2012 dollars)						
Brent spot crude oil (dollars per barrel)	113.24	111.65	108.99	119.45	141.46	165.57
West Texas Intermediate spot crude oil (dollars per barrel)	96.55	94.12	106.99	117.41	139.46	163.54
Natural gas at Henry Hub (dollars per million Btu)	4.07	2.75	5.23	4.96	7.65	7.97
Domestic coal at minemouth (dollars per short ton)	41.74	39.94	49.67	52.94	59.16	62.37
Average electricity price (cents per kilowatthour)	10.1	9.8	10.1	9.7	11.1	11.0
Economic indicators						
Real gross domestic product (billion 2005 dollars)	13,299	13,593	18,769	18,985	26,670	27,277
GDP chain-type price index (2005 = 1.000)	1.134	1.154	1.421	1.429	1.913	1.871
Real disposable personal income (billion 2005 dollars)	10,150	10,304	14,162	14,259	19,724	19,785
Value of industrial shipments (billion 2005 dollars)	5,926	6,147	8,778	8,548	10,994	10,616
Primary energy intensity (thousand Btu per 2005 dollar of GDP)	7.30	6.99	5.46	5.39	3.99	3.95
Population (millions)	312.3	314.6	347.0	356.5	380.5	404.4
Energy-related carbon dioxide emissions (million metric tons)	**5,498**	**5,290**	**5,526**	**5,501**	**5,599**	**5,691**

[a]Includes petroleum-derived fuels and non-petroleum-derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids and crude oil consumed as a fuel.
[b]Electric power sector consumption is distributed to the end-use sectors.

Notes: Quantities reported in quadrillion Btu are derived from historical volumes and assumed thermal conversion factors. Other production includes liquid hydrogen, methanol, and some inputs to refineries. Net imports of petroleum include crude oil, petroleum products, unfinished oils, alcohols, ethers, and blending components. Other net imports include coal coke and electricity. Both coal consumption and coal production include waste coal consumed in the electric power and industrial sectors.

Sources: AEO2014 National Energy Modeling System, run REF2014.D102413A; and AEO2013 National Energy Modeling System, run REF2013.D102312A.

TOPIC:

REFERENCE: YEC 2012-2013 GRA, Response to LE-YEC-1-27

"YEC is looking at options where heat from the LNG generation would be used, to the extent that is feasible, for district energy systems in Whitehorse."

December 9, 2013 Application, Page 42

"The Project's LNG development cost savings could be enhanced to the extent that lower natural gas prices are realized than the $4.5/MMBtu assumed in Yukon Energy's analysis, arrangements are made with Shell to facilitate lower cost delivery of LNG through provision of LNG to Yukon Energy at Fort Nelson, LNG powered trucks are implemented to reduce shipping costs, or district energy heat sales are realized from LNG."

PREAMBLE:

QUESTION:

a) Please provide details of the analysis that YEC has undertaken regarding using heat from the LNG generation for district energy systems in Whitehorse.

b) Please provide details from any studies known to YEC regarding the use of heat from the LNG generation for district energy systems in other jurisdictions.

ANSWER:

(a) and **(b)**

Yukon Energy completed in 2012 a district heat feasibility study for the City of Whitehorse in collaboration with the Yukon Government, the Energy Solution Center, the Yukon Research Center and the City of Whitehorse. As part of the YEC 2012/2013 General Rate Application, the Board noted the following in Board Order 2013-01 Appendix A: Reasons for Decision:

> "Further, the Board is of the view that district heating is not the type of activity to which YEC should be applying resources nor expecting recovery from ratepayers since it is not related to electric generation or transmission of electricity."

Based on the views of the Board, no YEC resources were allocated to the analysis of heat recovery from the natural gas generation and integration to a district energy system in Whitehorse. Yukon Energy, however, will be heating its Whitehorse diesel plant using natural gas and is currently assessing the feasibility of heating its other buildings located adjacent to the diesel plant, namely its office building and P125 hydro plant.

TOPIC:

REFERENCE: YEC 2012-2013 GRA, Response to YUB-YEC-1-49

"It is assumed in the referenced documents that LNG is supplied in the near-term by truck haul to Whitehorse from supply sources to be developed in northern British Columbia (Fort Nelson or Kitimat) for use at YEC's Whitehorse site (assumes simple cycle or combined cycle gas fired generation). Cost of LNG fuel was assessed at assumed natural gas prices (after inflation) in BC at $6.07/MMBTU in 2015, $8.05/MMBTU in 2020 and $11.07/MMBTU in 2030, assuming combined cycle generating units at 50% energy conversion efficiency (about 6.56 Mcg/MW.h), a 22 MW plant under Scenario A loads with DSM/SSE and an average annual plant capacity factor of 44%."

December 9, 2013 Application, Page 29

"Gas-fired engine fuel costs assume engine efficiency at 40%, and LNG supply from Shell Canada at Calgary (per Yukon Energy's contract with Shell and an assumed AECO gas price of $4.5 per MMBtu) using diesel powered A-Train trailers."

December 9, 2013 Application, Page 10

"The A-Train has been approved for use in Yukon for supply to Whitehorse along the Alaska Highway, but has yet to be approved for use in Alberta or British Columbia."

YEC Presentation at December 11, 2013 YESAB Public Meeting

"It has been transported and used in use in other parts of Canada, North America and around the world for over 50 years. LNG has a very good safety record with very tried and proven safety codes and standards that cover safe design, construction and operation."

PREAMBLE:

QUESTION:

a) Please explain why the LNG will be sourced from Calgary now instead of the originally proposed northern British Columbia and when this decision was made.

b) Please provide details of the source of the LNG being purchased through Shell.

c) Please provide details of YEC's analysis of the upstream impacts and emissions of natural gas extraction, processing and liquefaction related to the LNG to be used in the Yukon.

d) Please provide details supporting claims of LNG transport and use for past 50 years and evidence of the "very good safety record".

e) Please provide details of the safety records of A-Train trailers hauling LNG within Canada and the United States.

f) Please explain why the A-train has not been approved for use in Alberta and British Columbia.

g) Please provide details of emergency preparedness plans should anything happen while the LNG is being transported to Whitehorse.

h) Please provide details of emergency preparedness plans should anything happen while the LNG is being used in Whitehorse. Please identify the costs associated with ensuring that these plans and the agencies involved will be ready when an emergency occurs.

i) Please provide a copy of the report "Air Advisory: The Air Quality Impacts of Liquefied Natural Gas Operations Proposed for Kitimat, B.C." dated November 21, 2013 prepared for the SkeenaWild Conservation Trust. Please confirm that this report concluded that LNG plants permitted to operate primarily with natural gas will collectively burn 60% of all the natural gas burned annually in B.C., that nitrogen oxide emissions which cause respiratory problems from the LNG plants would increase 500% above existing levels, and that natural gas driven LNG plants will increase emissions in the Kitimat area of volatile organic compounds, carbon monoxide and sulphur dioxide.

ANSWER:

(a)

LNG sourcing reflects the best options available to YEC at the time such decisions are made. A contract was developed with Shell Canada at Calgary based on Shell Canada's plans to develop a facility at that location prior to the start of YEC's Project, and with total LNG volumes well in excess of YEC's requirements. At that time, this was the best option available to YEC.

To be clear, the above referenced quote regarding supply of LNG from northern British Columbia refers to discussions contained in the Summary Conclusions of YEC's Overview of the 20-Year Resource Plan: 2011-2030, and in the LNG Background Paper-January 2012 presented at YEC's January 2012 workshop on LNG. In both cases, the discussion relates to LNG as a potential supply option for Yukon at the pre-feasibility stage of assessment (i.e., no decision had been made regarding proceeding to feasibility stages of assessment or regarding the source of supply for LNG).

Please also see response to YUB-YEC-1-4(a) regarding the source of supply from Shell.

(b)

Please see response to YUB-YEC-1-4(a) regarding the supply from Shell's Jumping Pound plant at Calgary.

(c)

Yukon Energy has made results of life cycle assessments undertaken by third party experts (ICF Marbek and Pembina Institute) publically available. This material was also reviewed during the public consultation process for the Project (undertaken in July 2013, prior to preparation and filing of the Project Proposal with YESAB).

Please note that on December 9, 2013, YESAB issued a letter that indicated that the Executive Committee will not include natural gas extraction, processing, and liquefaction in the scope of the Project as these activities occur outside of Yukon and thus are beyond the authority of the Executive Committee to consider; the letter also stated that the Executive Committee also will not consider hydraulic fracking in Yukon in the

assessment of the Project (as this is not the LNG supply source identified in the Project proposal, and the possibility of hydraulic fracking as an activity connected to this Project is simply too remote and speculative for the Executive Committee to include it in its assessment).

(d) and **(e)**

Please see response to YUB-YEC-1-17(d) for details regarding the stringent standards and regulations for design, construction and operation for LNG transport, storage and vapourization facilities that have developed over the last 40 years to prevent accidents and minimize the adverse impacts of events. See also, YUB-YEC-1-17(e) for details regarding the number of LNG facilities currently in use in North America.

LNG as an industry has a very low accident rate. There are three major sectors and each has its own risk profile as noted below.

- **Land based LNG facilities** - In Canada these facilities are built to CSA Z276-11, and this standard contains siting requirements that reduce the risk to the public to near zero. There are currently well over 100 production, transport and storage facilities across North America, as well as a number of satellite facilities for LNG fueling and distribution. In the last 50+ years, there have been no members of the public injured as a result of LNG activities from a land based facility. In North America, there was one worker fatality that happened 30+ years ago. This accident was preventable and the current codes specify designs that eliminate the possibility of a recurrence.

- **Marine transport of LNG** – Marine transport moves massive amounts of LNG without injury or significant accidents. With regard to LNG marine shipping there has been no significant accidents or cargo spillage in 55 years (over more than 40,000 sea voyages and over 100 million miles)[1]. Over this period, the LNG industry grew to approximately 500,000,000 m^3/year of LNG transported from one country to another[2].

[1] The first LNG tanker carried liquefied natural gas from Lake Charles, La., to Canvey Island, UK in 1959. The first exports of LNG from the US to Asia occurred in 1969, with Alaskan LGN being sent to Japan from the Kenai Peninsula LNG plant.

[2] The world's LNG trade in 2011 was 241.5 million metric tons, or ~530,000,000 cubic meters. http://www.witherbypublishinggroup.com/Portals/0/pdf/Infographic-LNG-Industry.pdf

- **Land-based LNG transport** - Unlike land based LNG production and marine LNG transport, land based transport of LNG is subject to less controllable circumstances, such as road conditions, other drivers, and LNG driver error. The statistics show that accidents involving LNG land transport do happen; however, the available information indicates that accidents are infrequent and do not necessarily lead to LNG leaks, fire or loss of life.
    - In Europe, a 2004 Major Hazard Incident Data Base Service survey of historical data indicates that of 12,179 accidents contained in the database, 8.6% occurred during road transport, and only 1% (9 incidents in total) involved LNG. Of the nine incidents recorded, four corresponded to road accidents with neither LNG release nor fire, another three involved an LNG release which could be controlled, avoiding fire, and in the other, the tires and fuel of the truck ignited, but the LNG was not affected. There is only one case where LNG load was involved in a fire and resulted in loss of life (driver) and injury to two members of the public (first and second degree burns to individuals at a distance of 200 m from road tanker).
    - In a North American context, statistics available for Transgas (which operates one of the largest LNG trucking operations in the world),[3] indicate no reportable road accidents for the last 2 years (during which time they delivered 20,000 trailers of LNG)[4]. It is noted that Transgas operates in the heavily congested northeastern US which has aging infrastructure and challenging winter weather.
    - Available anecdotal evidence regarding North American LNG transportation indicates as follows:
        - In 1998, the driver of a tanker truck carrying 10,500 gallons of liquefied natural gas was killed when his vehicle flipped over on busy Route 128 in Woburn, MA. Diesel fuel tanks burst, setting the cab on fire – however, the LNG did not catch fire.

[3] Transgas is the transporter of LNG for Distrigas. New England relies on significant transportation of LNG by road tanker, with the Distrigas LNG Terminal in Everett, Massachusetts, supplying LNG via truck to nearly all 46 LNG storage tanks in the region through four truck loading bays with a maximum liquid send-out capacity of more than 4500 cubic metres of LNG per day. The terminal sends out 10,000 trucks of LNG each year to New England, New Jersey and Pennsylvania, making it one of the largest LNG trucking operations in the world. See http://www.distrigas.com/ourcompanies/lngna-domac.shtml.

[4] See http://www.transgaslng.com/safety/.

- In September 2003, an LNG truck overturned when it was going too fast on a freeway ramp. The trailer did not leak and there was no fire and no injuries, other than slight injuries to the driver. (In a 2 year period, there were 678 accidents reported on this particular interchange.)
- In May 2006 an LNG trailer went on its side. No report of leak or injuries, just 10 hour traffic delay.

(f)

Please see YUB-YEC-1-5(i), which reviews the regulatory process and timeframe to get A-Train approval for use in Alberta and B.C.

(g)

Under the Transportation of Dangerous Goods (TDG) regulations, the carrier or transportation company will have a written emergency plan to deal with any spills or accidental release of product while en route to Whitehorse.

Yukon Energy is working with the Fire Marshal Office to understand what is being done in Yukon municipalities in terms of emergency preparedness.

(h)

Maintenance and review of the Whitehorse Rapids Generation Site Spill Response Plan would cost approximately $3,000 per year. Training associated with spill response as well as emergency and fire response will cost approximately $6,000 year for YEC employees. No training costs have been associated with personnel in outside agencies.

In accordance with the Yukon *Oil and Gas Act*, an Emergency and Fire response plan is required for the proposed facility. This is currently being drafted and not ready for release. The Whitehorse Rapids Generation Site Spill Response Plan has been completed and updated with details of LNG and its associated fuels. The Spill Response Plan is provided as Attachment 1 to YUB-YEC-1-7(f).

(i)

The information requested does not relate to information prepared by, or relied upon by, Yukon Energy in relation to the proposed Project. UCG may file its own evidence following the processes outlined in the Board's rules of practice and procedure.

TOPIC:

REFERENCE: December 9, 2013 Application, Page 4

"The Project lies within the Traditional Territory of the Kwanlin Dun First Nation ("KDFN") and the Ta'an Kwach'an Council ("TKC"). In May 2012, TKC and KDFN were invited to become partners in assessing the feasibility of using LNG as a fuel source in Yukon and agreed to co-develop a Partnership Committee with terms of reference and signed confidentiality agreements completed July 2012. Regular partnership meetings have been held since July 2012, focused on review of the business case, establishing a good working relationship and making substantive progress toward developing economic and business opportunities for the two First Nations relative to the Project. This has also included discussion regarding a possible investment in the Project by TKC and KDFN through negotiation of a Partnership Agreement."

PREAMBLE:

QUESTION:

a) Please confirm whether the Kwanlin Dun First Nation and/or the Ta'an Kwach'an Council will be equity partners in the proposed project. If yes, please provide details of this partnership and the investments that the two First Nations will be making.

b) Please confirm whether both of these First Nations are in full support of the proposed project.

ANSWER:

(a)

Both Kwanlin Dün First Nation (KDFN) and Ta'an Kwäch'än Council (TKC) had partnership opportunities in the proposed Project including investment opportunities.

Please see response to YUB-YEC-1-18(d) for further details.

(b)

KDFN and TKC have been actively engaged in the Project since May of 2012. TKC withdrew its support on December 18th, 2013. Please see response to YUB-YEC-1-18(d) for further details.

TOPIC:

REFERENCE: December 9, 2013 Application, Page 25

"The Corporation will be able to utilize some of the parts off of the retiring WD1 and WD2 engines to keep the two refurbished units operating prior to currently planned retirement dates."

PREAMBLE:

QUESTION:

a) Please provide details of the salvage value for the diesel-fuelled generating units being replaced and where this has been incorporated into the cost of the proposed project.

b) Beyond salvage and part recycling, please provide details of any other uses considered for these diesel-fuelled generators.

ANSWER:

(a) and **(b)**

Please see response to YUB-YEC-1-20.

TOPIC:

REFERENCE: December 9, 2013 Application, Page 9

"The November 2013 update to Yukon Energy's 20-Year Resource Plan load forecasts (see Appendix C) indicates that 7.0 MW of additional grid capacity is required by 2015 at the latest for replacement of the two Mirrlees units at the WTGS that are to be retired in 2014 and 2015."

PREAMBLE:

QUESTION:

a) Please provide details of when and how the November 2013 update to YEC's Resource plan has been reviewed by the YUB and other parties.

ANSWER:

(a)

The November 2013 update to YEC's Resource Plan load forecasts (Appendix C of the Part 3 Application) was prepared specifically for the purposes of supporting the Project Part 3 Application and it is expected that it would be reviewed as part of the current proceeding.

TOPIC:

REFERENCE: December 9, 2013 Application, Page 38

"Forecast grid loads may potentially be reduced below the Base Case forecast in Appendix C due to loss of industrial load (Minto) and/or reduced residential/ commercial load due to economic downturn, or due to DSM/ conservation programs being more successful than currently forecast.

PREAMBLE:

QUESTION:

a) Please confirm that Capstone Resources' Minto mine began laying off workers in January 2014, slowing mining in its pit, cutting production from about 10,900 cubic metres per day to about 5,000, and that Minto is hoping that permits will be approved by August 2014 when the existing pit is shut down.

b) Please confirm that the reduction of production by over 50% would mean that the Minto mine would no longer be considered a major industrial customer of YEC.

ANSWER:

(a)

Yukon Energy does not expect the issues surrounding the permitting of the new open pit operation to affect current operations or near term load. It is understood that Minto is actively mining underground and blending with lower grade open pit ore to keep the mill full and that the Minto forecasts are not expected to drop in the near term (and may be higher than forecast).

(b)

OIC 1995/90 defines a major industrial customer as “means a customer engaged in manufacturing, processing, or mining, whose peak demand for electricity exceeds 1 MW, but it does not include an isolated industrial customer.”

Appendix C provides a forecast Minto load (with grid losses) for 2014 of 38 GWh and for 2015 of 40.2 GW.h; these load levels reflect forecast Minto peak demand (excluding grid losses) of 4.8 MW in 2014 and 5.3 MW in 2015. Even with a 50% drop in production it is expected that Minto would have a peak demand that exceeds 1 MW.

TOPIC:

REFERENCE: December 9, 2013 Application, Page C-2

"In July 2013 Alexco Resource Corp. announced that it will close Bellekeno mine for winter and will reopen in spring of 2014 assuming the silver market has improved."

PREAMBLE:

QUESTION:

a) Please provide a copy of Alexco's Updated Preliminary Economic Assessment for the Eastern Keno Hill Silver District Project – Phase 2, Yukon, Canada dated November 15, 2013 plus any other public updates that Alexco has made since the time of this report.

b) Please confirm that the November 2013 assessment by Alexco indicates that stoping and processing at the Bellekeno mine would not be re-starting prior to January 1, 2015.

c) Please provide an analysis of the value of silver since Alexco closed the Bellekeno mine.

ANSWER:

(a)

The requested document is publically available on Alexco's website at the link below, as such, intervenors may reference this document in their own evidence if they so choose.
http://www.alexcoresource.com/i/pdf/reports/Alexco_PEA_EKHSD_20131115.pdf

Intervenors may also reference any other public updates that Alexco has made. Yukon Energy's load forecast (and the basis for the forecast are set out in Appendix C of its Application) is based on the best information available to YEC at the time the Application was prepared.

(b)

With regard to the Bellekeno mine, the referenced document notes at page 19 as follows:

> "In production since 2011 until temporary suspension of operations at the end of August 2013. This preliminary economic assessment (PEA) assumes that production stoping [sic] will re-start January 1, 2015."

Please note that Appendix C of the Application provides updated near term grid load scenarios and notes (based on Alexco's July 2013 announcement) that while the Bellekeno mine could re-open in spring 2014, assuming the silver market has improved, there is no current basis for addressing a 2014 forecast update and the timing of reopening of the mine is very uncertain. Consequently, to be conservative, the economics for the Project as provided in the Application were prepared assuming no Alexco in the Base Case forecast. However, Appendix C also note Alexco's December 5, 2013 announcement of a strategy to initiate development of the Flame & Moth mine in 2014 as a first step in achieving commercial production from this deposit in 2015; recommissioning of the Bellekeno mine would begin later in 2014 so that this mine would be ready to simultaneously go into production along with Flame & Moth near the beginning of 2015 - and the current Appendix C forecast update has not attempted to assess Alexco's loads specific to this December announcement.

In summary, the Base Case with no Alexco is intended to be a conservative assessment of potential load requirements in the near term. The Base Case with Alexco would more closely resemble a "likely" scenario at this time based on Alexco's stated plans to resume operation early in 2015. Please also see response to CW-YEC-1-13(b).

(c)

Yukon Energy does not base its forecasts on metal prices (and cannot therefore provide an analysis on the value of silver prices since the closure of the Alexco mine, or the extent to which such prices are a key factor for Alexco's future actions). Yukon Energy understands that it is unlikely that the mine will reopen in 2014. As noted in (a) above, due to the uncertainties noted, Alexco load was not included in the Base Case forecasts used for the purposes of the economic analysis for the Project as provided in the Application.

TOPIC:

REFERENCE: **Minister's Referral to YUB (December 20, 2013) - Terms of Reference**

"The YUB shall report on and make recommendations about the necessity for the Whitehorse Diesel-Natural Gas Conversion Project and its timing and design, with particular regard to:

a. The public need for the Whitehorse Diesel-Natural Gas Conversion Project under various reasonable electric load forecasts, including near term requirements related to industrial and non-industrial loads, and the effect of the project on the rates of customers"

PREAMBLE:

QUESTION:

a) Please provide details of where in YEC's application the public need is addressed.

ANSWER:

(a)

Public need is addressed in Section 4 (Project Justification); page 17 provides a summary of the Project need as follows:

"The Project will provide reliable and flexible new generation capacity required today at Whitehorse to meet Yukon Energy's reserve capacity planning criteria for the Yukon grid, including reserve capacity for seasonal low water periods and drought years while supplying short-term non-industrial load growth and peak winter demand. With conversion of generation from diesel to natural gas supplied by LNG, the Project will reduce Yukon Energy's forecast fuel costs, reduce forecast greenhouse gas and particulate emissions, and stimulate oil product-natural gas conversions in other sectors of the Yukon."

Further detail is provided in the balance of Section 4 under the following headings:

- Section 4.1 - Yukon Grid Context & Changing Grid Load Conditions;
- Section 4.2 - Need for and Alternatives to the Project; and
- Section 4.3 - Risks and Potential Impacts on Ratepayers.

TOPIC:

REFERENCE: **Minister's Referral to YUB (December 20, 2013) - Terms of Reference**

"The YUB shall report on and make recommendations about the necessity for the Whitehorse Diesel-Natural Gas Conversion Project and its timing and design, with particular regard to:

> b. The capability of existing and currently committed generation and transmission facilities including thermal generation facilities to provide reliable electric power generation to meet the forecast load requirements and YEC's capacity planning criteria, and the effect of the Whitehorse Diesel-Natural Gas Conversion Project on this capability."

PREAMBLE:

QUESTION:

a) Please provide details of where in YEC's application the capability of existing and currently committed generation and transmission facilities is addressed.

ANSWER:

(a)

Capability of the existing and currently committed generation and transmission facilities is addressed in Section 4.1 (Yukon Grid Context & Changing Grid Load Conditions) which reviews the following:

- Yukon Grid Context (Section 4.1.1);
- Changing Grid Load Conditions (Section 4.1.2);
- Forecast Grid Diesel Energy Requirements without Major New Mines or New Sources of Generation (Section 4.1.3); and
- Forecast new Grid Capacity required without Major New Mines (Section 4.1.4).

Further detail regarding updated grid load forecasts is provided in Appendix C.

TOPIC:

REFERENCE: City of Whitehorse Submission to YESAB dated January 10, 2014

PREAMBLE:

QUESTION:

a) Please respond to the concerns and recommendations addressed in the City's submissions and explain how the permits identified will be addressed and whether any of this work will impact the in-service date for the proposed project.

ANSWER:

(a)

Please see response to CW-YEC-1-1 regarding Yukon Energy's response to concerns and recommendations addressed in the City of Whitehorse's Submission to YESAB dated January 10, 2014. Yukon Energy is working closely with the City of Whitehorse Planning Department to ensure issues and concerns that the City have are appropriately addressed prior to the planned Project in service date.

TOPIC:

REFERENCE: John Maissan Submission to YESAB dated January 10, 2014

PREAMBLE:

QUESTION:

a) Please comment on Mr. Maissan's submission that regulators addressing the proposed project should be addressing the cumulative effects of producing and burning fossil fuels that affects both the health and lifestyle of residents of the Yukon and the residents of Canada outside Yukon as well.

ANSWER:

(a)

The Project Proposal filed with YESAB addresses the cumulative effects of the Project relevant to the YESAB screening of the Project.

Chapter 7 of the Project Proposal filed with YESAB considers Project cumulative effects as relevant. In environmental assessment, cumulative effects examine the likely adverse effects of the Project in combination with the likely effects of other past, existing and future projects and activities. To be considered a cumulative effect, the other past, existing and future projects being considered in the assessment must affect a valued environmental component that is also being adversely affected by the principal project; in this way the projects act cumulatively upon a valued component. The assessment must consider the world as it unfolds without the Project and the world as it unfolds with the Project.

With regard to burning and producing fossil fuels it is noted that without the Project, YEC would be required to burn diesel fuel to meet incremental load requirements related to outages, water variability and peaking. Chapter 7 of the Project Proposal filed with YESAB summarizes that the Project's use of natural gas rather than diesel (as well as the use of new and more efficient engines compared to existing diesel units) is expected to have the following emissions effects:

- Notable positive effects by reducing air emissions related to NOx, PM, and SO2 (particulate emissions of existing diesel units were noted in the SENES 2011 dispersion analysis as the only emission from the WTGS to exceed 50% of Yukon Ambient Air Quality Standards (YAAQS) at the Max POI); and

- Small adverse effects by increasing air emissions related to CO and VOC which, in each instance, are small in magnitude and occurring at the Project Study Area scale, and are accordingly assessed to not be significant (for the reasons set out above).

The YESAB submission reviewed other potential Projects and activities in the area with the potential to have effects on air quality that overlap with the effects of the Project. It was noted that effects of other existing[1] and future[2] projects on air quality relate primarily to dust and vehicle emissions. An air emissions permit related to emission of criteria air contaminants (such as CO or VOCs) had not been identified as a requirement for any of the projects examined. Given the short-term and small magnitude of Project effects related to dust and vehicle emissions and location of other projects a distance away along the Copper Haul Road, no cumulative adverse effects were expected.

The Project is expected to result in reductions in greenhouse gas (GHG) emissions, and as a result these emissions were not assessed further[3].

[1] Annie Lake Trucking Ltd Gravel Quarry (YESAB Registry number 2011-0129) and the Concrete Batch plant on McLean Lake Road (YESAB Registry number 2010-0228).

[2] Lot 1247 McLean Lake Road (YESAB Registry number 2013-0018), the Yellow Truck Excavating Gravel Quarry (YESAB Registry number 2013-0015) and the Whitehorse Copper Tailings Reprocessing and Reclamation project (YESAB Registry number 2011-0064).

[3] Emissions from diesel generation from the National Inventory Report (Environment Canada) average approximately 697.5 tonnes of CO2e per GW.h, while natural gas emissions from combustion equal approximately 451 tonnes of CO2e per GW.h.

Yukon Conservation Society
and
Leading Edge Projects Inc
(YCS/LE)

TOPIC:

REFERENCE: Page 1

"The Project will modernize Yukon Energy's Whitehorse Thermal Generating Station ("WTGS") ..." and "The Project scope will involve replacing two diesel generating units scheduled for retirement in the existing WTGS by 2015 (9.1 MW total nameplate capacity) and the installation of LNG truck offloading, storage, vapourization and related infrastructure in the Expanded Site Area."

PREAMBLE:

QUESTION:

a) Please confirm that installing new diesel generators would also modernize the WTGS.

b) Are the "Project" and the "Project scope" as described on page 4 the same?

ANSWER:

(a)

Installing new diesel generators would modernize the WTGS, and absent the opportunity for changeover to natural gas, would be required today.

Installing new diesel generators would ignore the opportunity today to convert from diesel to LNG-supplied gas-fired generation to meet growing electricity loads on the Yukon grid with a fuel that is cleaner burning and less costly than diesel, benefiting both the environment and Yukon ratepayers.

(b)

"Project" is a defined term in the document and means (as defined on page 1) the Whitehorse Diesel-Gas Conversion Project as defined in OIC 2103/00 for which the

Application has been submitted. The Project scope (as described on page 4) simply summarizes the key components of the Project that YEC is proposing to carry out.

TOPIC:

REFERENCE: Page 1

"...replacing two diesel generating units scheduled for retirement ...(9.1 MW nameplate Capacity)..."

PREAMBLE:

QUESTION:

a) Please confirm that the 2011 Resource Plan rating for these two generators is 8.0 MW.

b) Please explain and justify the reduction in ratings from the 2006 to 2011 Resource Plans for the EMD generators in Whitehorse as well as the Caterpillar generators in Whitehorse, Faro, Dawson City, and Mayo (total reductions 2.09 MW).

c) Are the differences in (b) due to differences between the manufacturer's maximum continuous ratings and a shorter term peaking rating? Do these generators also have higher manufacturer's ratings based on noncontinuous usage (e.g. a stand-by rating or a 1 hour rating), and if so please specify and list all the manufacturer's ratings for each engine. Please justify why the higher non-continuous ratings should not be used for emergency back-up capacity calculations as opposed to base load operations.

ANSWER:

(a)

The nameplate capacity for WD1 and WD2 is 9.1 MW. The MCR rating is 8 MW as of 2011. This rating is less than the 2006 resource plan rating due to the continued deterioration of the engine and generator. The reserve capacity planning analysis undertaken with regard to the 2011 Resource Plan was based on MCR ratings.

(b) and **(c)**

The changes in the unit ratings reflect new MCR ratings of 8.85 MW for Faro Diesel and 22.5 MW for Whitehorse Diesel. MCR ratings are used for reserve capacity purposes for two reasons;

1. The peak demands used for reserve capacity purposes are hourly demand as recorded by the Corporations SCADA hourly logs. The instantaneous or short duration demands are higher. MCR rating are used for the purpose of meeting the hourly peak demand, in recognition, that for meeting instantaneous peak demands, a higher engine output can be tolerated for a short period of time.

2. Backup unit capacity may be required for an hour or for days, depending on the circumstances, so use of a short duration peak rating is a risk to customers not worth taking.

MCR ratings may also change over time base on the age/condition of the engine and /or generator.

TOPIC:

REFERENCE: Page 1

"...Yukon Energy continues to pursue potential near-term hydro enhancement projects, including Mayo Lake Enhanced Storage and Marsh Lake (Southern Lakes) Storage. For future consideration when higher long term grid loads can justify such developments, Yukon Energy is also pursuing wind development that could range up to 20 MW at Techo ... as well as potential future hydro generation at various potential greenfield sites."

PREAMBLE:

QUESTION:

a) Please provide the full details of the financial analysis that is used to compare renewable sources of energy and capacity with the Project including but not limited to the length of the evaluation period, the weighted average cost of capital, debt amortization periods, any unit energy calculations, any net present value analysis and treatment of fuel and carbon price risk including all details of the methodology used.

b) Please provide a detailed description of all the facilities that were included as part of the Project to do the comparative analysis?

c) Please provide Yukon Energy's long term natural gas, diesel/oil and carbon price forecasts.

d) Please confirm that 60-70% of the cost of generating electricity from the natural gas fired thermal units will be the cost of re-gasified natural gas.

e) Please confirm that both Mayo Lake and Marsh Lake enhanced storage would be subject to the same potential drought conditions for the purposes of producing energy as discussed in this application (e.g. on page 20). Would reliance on these projects not exacerbate diesel (or LNG) generation requirements during

drought years (like 1996-2000) compared to other forms of generation not subject to the risk of drought?

f) Please provide a detailed update on Yukon Energy's actions since Yukon Energy's last GRA with respect to advancing a potential wind development project at Techo.

g) Please explain Yukon Energy's approach in selecting and advancing other potential new hydro sites with respect to mitigating the effect of the drought periods with respect to producing energy experienced in the present hydro facilities.

ANSWER:

(a) and **(b)**

The need for the Project is driven by the capacity requirements noted in the Application, which involve replacing two diesel generating units scheduled for retirement by 2015 with up to three new modular natural gas-fired generating units. As noted in the Application, there are no feasible renewable resource alternatives to the Project within the relevant time period that could meet this specific need. Therefore, no analysis were done, which compares the Project to specific renewable options as part of the Application. Part 3 Application compares the LNG Option to the available diesel options (New Diesel and WD1/WD2 life extension). Please see Table 4-3 of the Application for detailed annual impact analysis.

As background, it is noted that YEC reviewed at length all available resource options in its 2011 Resource Plan, including the implications of different possible portfolio options in light of Yukon's isolated grid, specific loads scenarios, and potential options relevant to grid electricity generation planning. With regard to information on renewable resource options, please see response to CW-YEC-1-10(a,b); YCS/LE-YEC-1-27 and 59; YUB-YEC-1-49.

(c)

YEC does not provide long-term forecasts of natural gas, diesel/oil or carbon prices.

The Application reviewed information regarding the expected future long term relationship between domestic North American gas prices and world oil prices, e.g., Figure 4-2 was provided based on the U.S. Energy Information Administration's Annual Energy Outlook for 2013.

(d)

The annual cost will depend on thermal generation required to supply energy to the Yukon Grid. For example, as provided in Table 4-3 of the Application based on long-term average hydro, about 46% of the annual cost related to LNG plant and LNG generation would be LNG fuel cost. This would increase to 60% in 2018 as the annual depreciation and return will reduce, and LNG generation will increase.

(e) and **(g)**

Yes. The hydro enhancement projects, such as Mayo Lake Enhanced Storage Project and Marsh Lake Storage Project, would be subject to potential drought conditions. However, these projects propose to increase the volume of usable water storage for the purpose of energy generation, which in turn can help to reduce the risk of higher thermal generation in drought conditions. Other renewable projects may also be subject to reduced generation due to temporary environmental changes.

(f)

Please see response to YUB-YEC-1-49.

TOPIC:

REFERENCE: Page 4

"...TKC and KDFN were invited to become partners ... substantive progress toward developing economic and business opportunities for the two First Nations relative to the Project. This has also included discussion regarding a possible investment in the Project by TKC and KDFN through negotiation of a Partnership Agreement."

PREAMBLE:

QUESTION:

a) Please provide copies of the Partnership Agreements (and any other agreements with respect to this project) with the TKC and KDFN.

b) Please describe in detail the economic and business opportunities discussed.

c) Do the economic and business opportunities involve or contemplate any natural gas (vapourized LNG) or LNG for transportation or other purposes being supplied from the Project's LNG storage facilities to locations outside the Expanded Site Area? If so please detail any and all arrangements or the possible/potential arrangements.

d) Do the economic and business opportunities involve or contemplate any payment streams to Yukon Energy? If so please provide the details.

e) With respect to a possible investment in the Project please indicate whether TKC and KDFN would provide some debt, equity, or both toward the proposed Project cost of $38.8 million.

f) Please confirm that the return on equity and the interest rate on debt for TKC and KDFN would be as ordered by the YUB for Yukon Energy in the most recent GRA. If not please provide the debt and/or equity returns they will receive.

g) Please provide evidence that both First Nations support the Project.

ANSWER:

(a)

The requested information is subject to a confidentiality agreement and cannot be provided.

(b)

Please see response to YUB-YEC-1-18(c).

(c)

KDFN is exploring potential wholesale/retail opportunities. This business activity would be physically and financially separate from YEC's LNG facility. With regard to providing any further detail regarding specific arrangements, discussions are ongoing and subject to the provisions of a confidentiality agreement.

Please see response to YUB-YEC-1-18(c).

(d)

First Nations economic and business opportunities are bilateral, involving payments between YEC and First Nations

Potential "payment streams" contemplated by a First Nation partner to Yukon Energy may include potential investment in the Project and the potential purchase of LNG from YEC's surplus supply capacity and/or inventory. With regard to providing any further detail regarding specific arrangements, discussions are ongoing and subject to the provisions of a confidentiality agreement.

(e) and **(f)**

Discussions regarding investment opportunities are ongoing and subject to the provisions of a confidentiality agreement.

(g)

The two First Nations, Kwanlin Dün First Nation Ta'an Kwäch'än Council, have engaged with YEC since June 2012 as "Project Partners" to work towards a potential business relationship.

TKC withdrew from the partnership discussions on December 18, 2013
KDFN remains fully supportive of the Project.

Please see also YUB-YEC-1-18(d).

TOPIC:

REFERENCE: Page 5 (and elsewhere) Re modular gas generating units

PREAMBLE:

QUESTION:

a) Please explain how and why Yukon Energy selected "modular" units in preference to other generator / building options including but not limited to such as gas generator units housed in a pre-engineered building.

b) Please explain why Yukon Energy did not select dual fuel (natural gas – diesel) generating units.

c) Please explain why Yukon Energy did not select generating units that could be fuelled by LNG in combination with diesel in order to avoid the cost of re-gasifying LNG.

d) Please provide the advantages and disadvantages of all the options considered and evaluated.

e) Please provide a copy of the Request for Proposal (RFP) or Request For Expression of Interest (RFEI), or the relevant documentation of the process, if other than one of these, that Yukon Energy used in the solicitation of potential candidates for a gas generator supplier.

f) Please list the suppliers that responded and explain how and why GE was selected.

ANSWER:

(a), **(b)**, **(d)**, **(e)** and **(f)**

In January 2013 Yukon Energy issued a Request for Information (RFI) (provided as Attachment 1 to this response) to engine suppliers for budgetary estimate for dual fuel

(natural gas and diesel) and/or single fuel natural gas reciprocating and/or gas turbines in the range of 1 MW to 8 MW to be in service at the WTGS by the end of Q3 2014, including information on engine performance, technical descriptions, specifications and dimensions, fuel blending options and key commercial terms. The RFI provided YEC with information on relevant options then available in the near term for new natural gas or dual fuel capacity at the WTGS, with a specific intent to define the maximum scale options that could be accommodated in the WD1 and WD2 service bays (up to a total of 14 MW, i.e., not exceeding 5 MW above the rated capacity of WD1 and WD2) when these units are decommissioned. The following summary information is provided on the RFI outcomes:

- Respondents to this RFI included Wartsila and MAN with a range of dual fuel engine options, and several gas fired reciprocating engine suppliers (including Wartsila, GE, CAT, and Bergen Rolls Royce).

- Maximum new capacity that can be installed in the WD1 and WD2 bays was indicated to be provided by Wartsila - with 9.3 MW and 7.4 MW gas engines, and 8.4 MW and 6.7 MW dual fuel engines, that can likely fit in WD2 and WD1 engine bays respectively.

- Comparison of dual fuel and gas-fired only engine options determined that equivalent gas fired engine options offer a range of relatively small magnitude advantages over duel fuel options, including increased capacity, lower capital cost per unit and higher operating efficiencies as well as a greater number of vendors, wider range of capacities available and greater displacement of diesel fuel. The prime advantage for the dual fuel engine option is flexibility in both the near term (if any issues with LNG supply, as well as lower LNG storage cost requirements) and longer term (ability to switch to diesel if gas price increases over diesel within next 15 to 30 years).

- A review of engine design criteria in the context of Base Case loads also indicated advantage in terms of overall operating efficiency savings of selecting two 4.4 MW units instead of one 8.4 MW or 9.3 MW unit to serve loads in 2014-16 timeframe. At Base Case loads the utilization of the initial gas fired units may fluctuate widely between seasons, years and other time periods such that efficiency over a wide range of operating conditions may be a premium requirement at this initial development stage. Smaller units were not previously

considered for initial development using the existing building as use of smaller units would conflict with the objective of utilizing the WD1 and WD2 unit bays to install the largest feasible new capacity.

In summary, the RFI focused on selecting the largest feasible capacity for new units in the WD1 and WD2 service bays. The RFI information indicated a basis to focus on dual fuel units (to secure added flexibility without a material loss of efficiency) and that the 6.7 MW Wartsila units were the largest dual fuel units that could be located in both the WD1 and WD2 service bays. Related analysis also highlighted potential advantage at the outset in selecting two smaller capacity units instead of one larger unit to serve load in the 2014-2016 timeframe, however, this option would under-utilize the full potential of the WD1 and WD2 service bays. Preliminary engineering also indicated that utilizing the existing WD1 and WD2 service bays for new units would create material schedule risks (and grid reliability concerns if delays occur) due to the need to retain existing units in service until at least March, and then to remove the existing unit and install the new one prior to December of the same year and, as a result, would likely also delay the project for a year.

Further to the RFI process, meetings with GE in late February 2013 introduced the option for smaller pre-engineered modular gas engines installed on a pad outside the existing diesel plant. This new option was determined to be available in the time period specified in the RFI, and offered several clear advantages over the original proposed approach to install initial new units in the existing WD1 and WD2 service bays, including:

- Removes the specific scheduling risks associated with using the existing WD1 and WD2 service bays for the initial new gas-fired engines;

- Facilitates securing the operating efficiency advantages noted for smaller initial units, while preserving the option in future to install maximum capacity units in the existing WD1 and WD2 service bays; and

- Potentially eliminates the need for material infrastructure or balance of plant facilities beyond the pad or piling foundation (in contrast, the option with new units in the WD1 and WD 2 bays would required material infrastructure or balance of plant facilities within an existing building, adding to on-site construction period risks and complexities).

Subsequent review of potentially available modular unit options indicated that GE is the only vendor currently offering such options in the scale relevant to YEC and with demonstrated cold climate northern operating experience, and that no dual fuel option is available at this time for the modular unit approach.

Subsequent review also identified the pre-engineered J624 modular unit option as the preferred GE modular engine option for the Project and that costs for this option. This is GE's largest gas unit available as a pre-engineered modular unit. It was initially designed to withstand cold climate conditions and has an operating plant in use in northern Russia. This scale of unit was concluded to be the relevant modular option for the Project, i.e., two of these units (approximately 8.8 MW total new engine capacity) would accommodate initial capacity requirements for 2015 and a third unit (approximately 13.1 MW total new engine capacity) would fall within the 14 MW limit for the Project and meet expected capacity requirements for 2017.

Please also see response to YUB-YEC-1-15(a) through (c).

(c)

It is not clear what is being asked in the question. The RFI process and other investigations to date have not identified an option whereby "generating units …could be fueled by LNG in combination with diesel in order to avoid the cost of re-gasifying LNG." Each option reviewed that involves use of natural gas required that the LNG be gasified through vapourization.

YEC did not at this time pursue a fuel blending option (where gas is blended with diesel fuel in a modified existing engine unit). The focus was on securing maximum feasible energy efficiency gains through new units (gas or diesel) being used to replace the retired Mirrlees units, and in this manner help to ensure that this initial step in conversion to natural gas from diesel would provide overall cost savings at this time. As noted in the Application, once the Project is developed fuel blending options will be examined for the remaining EMD and CAT engines in order to enhance use of the available LNG.

REQUEST FOR INFORMATION

NO. 2013-002

Budgetary Estimate for Dual Fuel and/or Single Natural Gas Reciprocating Engines and/or Gas Turbines

January 21, 2013

NOTICES/INSTRUCTIONS

1.1 INTRODUCTION

This request is for information only to assist Yukon Energy Corporation in determining how best to fulfill requirements described herein.

Please be advised that this may be a two-step process. Should Yukon Energy Corporation determine to proceed with a solicitation based on the responses to this Request for Information (RFI), phase two will then be a formal Request for Proposal (RFP) or Request for Tender (RFT) and be handled in accordance with Yukon Energy Corporation procurement policies and procedures.

1.2 PURPOSE

The purpose of this Request for Information (RFI) is to solicit technical and performance narratives along with budgetary pricing information from vendors; or identify additional supply or product resources.

1.3 BACKGROUND

Yukon Energy currently operates its diesel generation to meet peak loads specifically during the winter months when water availability for hydro generation is limited. It is forecasted that organic growth in demand and the significant industrial loads with in-service date in the next three years will require a material increase in use of diesel

generation required to meet this load. As such, YEC is looking at liquefied natural gas (LNG) as a transitional source of energy to meet the future needs for base load and intermediate load use. The LNG would come from Alberta and/or British Columbia and be transported by truck to the Yukon. The LNG would be offloaded from the trucks to a storage facility to be located near the existing YE facility. From there, the LNG would be vaporized and conveyed via underground pipes to YE's Whitehorse diesel plant (P126). New natural gas fired or dual fuel generators would be located in the existing P126 plant.

The magnitude of the planned industrial demand growth is also expected to put an additional demand on grid generation. As such, to minimize some of the effects on the system Yukon Energy is also investigating the potential for fuel switching (diesel to natural gas) in other existing plants located north of Whitehorse or install new generation at the planned industrial site.

1.4 **OBJECTIVES:**

The objective of the current RFI is to address the following info requirements:

1. Provide budgetary estimate for dual fuel (natural gas and diesel) and/or single fuel natural gas reciprocating engines and/or gas turbines for stationary power plant in the 1MW to 8 MW range. Capacity can be adjusted based on manufacturer's current engine/turbine sizes. Depending on the location where the engine will be installed, it will be operated to meet peak demand but also for continuous power should there be a benefit in utilizing waste heat.

2. Provide engine performance indicators (output values including LHV efficiency)

3. Provide a technical description, specifications and dimesions for the engines in the 1-8 MW capacity range suited for continuous operation.

4. Provide information on the potential for new or retrofitted diesel engines made by the manufacturer for fuel blending (natural gas and diesel). If so, provide budgetary pricing, range of practical fuel mixture ratios and estimated engine efficiencies.

5. Provide a description of any price conditions and preferred payment terms.

6. Provide an estimate of delivery time between date of signature of supply contract and time when the unit is ready for shipment from the factory.

7. Assume the units are FOB Vancouver, British Columbia.

8. Address current status of unsold production capacity.

9. Provide description of warranty period.

1.5 Working assumptions

To help with the generation of budgetary pricing, the proponent shall assume the following components are included:

- Engine
- Generator
- Control panels for engine and genset (including cables and accessories)
- Frame for Engine and Generator
- Exhaust system (assume standard installation)
- Heat recovery system (jacket and flue)
- Cooling system (assume air/glycol heat exchanger with radiators)
- Mechanical auxiliary equipment for engine and exhaust gas module
- Connections between engine and external piping
- Gas system (e.g. gas regulating features, shutoff valve, gas flow meter, etc.)
- Lube oil system (transfer unit, separator unit)
- Compressed air system
- Oil-water processing unit
- Standard fire protection units
- Station service system
- Gas detection system
- DC system
- Engineering (including PM, process, electrical, mechanical, civil, structural)
- Engine specific maintenance tools and spare parts
- Engine factory testing*
- Training (onsite and at facility)
- Documentation (conceptual design, detailed design, construction, operating, etc)
- Transport to Vancouver (includes packing, transport to shipping facility, pre/post shipping inspections, loading on ship - trucks if manufacturer is based in North America, bill of lading, origin country documents for Canadian customs, unloading at receiving facility in Vancouver, BC)
- Technical supervision during installation
- Engine commissioning

1.6 Working Exclusions

The following items are excluded from the current scope:

- Site infrastructure (including power house building, electrical installations, building heating, amenities, underground network)

- Site preparation
- Foundation block (please include general specification when available)
- Site drainage
- Plant fire suppression system
- HV system
- MV switchgear
- HV cables other than included with unit
- Step-up transformer
- Natural gas pipes
- Transportation from Vancouver to final destination in Yukon
- Installation work
- Communication system/SCADA system
- Tanks for diesel and/or natural gas short-term/long-term storage

2.0 ANTICIPATED SCHEDULE

The Corporation anticipates a marked increase in demand for electricity over the next 20 years. The addition of industrial customers to the organic load growth will increase significantly the demand. The Corporation's existing hydro facilities will not be able to meet this demand and as such, will have to rely on more costly diesel generation to meet the demand. Accordingly, purchase and installation of natural gas fired reciprocating engines either for the Whitehorse facility or at other plants by the end of Q3 2014 is of critical importance to the Corporation.

3.0 QUESTIONS & QUERIES

Proponents are required to submit their questions, including questions relating to specifications, discrepancies, omissions, or any apparent ambiguities, in writing, by e-mail, in accordance with the schedule set out below, to:

Yukon Energy Corporation
Attention: Lynda Harlow ("Corporation's Designate")
Telephone: 867-393-5302
E-mail: lynda.harlow@yec.yk.ca

Proponents will not contact or ask questions of any other Corporation personnel. Information obtained from any person or source other than the Corporation's Representative cannot be relied on for the purposes of this RFI process.

To facilitate the question and answer process, the Corporation will use the schedule identified below for the receipt of questions and delivery of the Corporation's responses. The Corporation will make a reasonable effort to have the responses issued by the end of business on the Corporation's Response Date.

	Submission Date	Corporation's Response Date
Q&A Session #1	January 25, 2013	January 28, 2013

4.0 SUBMISSION REQUIREMENTS

As of February 1, 2013 the alternate Corporation Designate is Matthew Sills. Please submit responses to this RFI electronically to matthew.sills@yec.yk.ca as PDF or as MS Word attachments no later Friday February 4th, 2013 at 4:00:00 PM PST Whitehorse Local Time.

CD's with product demonstrations, digital marketing brochures and technical documentation are encouraged but not required for this RFI. If available, marketing materials shall be sent to:

Yukon Energy Corporation
Attn: Procurement
RFI 2013-002
PO Box 5920
#2 Miles Canyon Road
Whitehorse, YT
Y1A 6S7

The RFI response should contain the following:

- Contact Information
  Please provide the following contact information:
  - Company Name and Headquarters Mailing Address
  - Contact Name, telephone and email;
  - Company Website URL
  - Location of Customer Support Staff
  - Type of Organization (Corporation, Partnership, etc.)
  - How long has the company been in business in its current form?
  - Provide description of previous experience in projects similar in scope

- Comments
  Please provide your evaluative comments on the Objectives outlined in this document. Include any suggestions or advice regarding the design, implementation, management, technology, etc. of this contemplated project. Detail what additional information or clarifications would be needed in order to prepare a comprehensive proposal in the future?

- Approach
  Based on the project information provided to date, briefly describe the approach you would recommend for this project and why.

5.0 OUTCOME

Yukon Energy Corporation does not guarantee any formal solicitation will be generated based on this RFI. No award will be made based on the results of this process. Any procurement by Yukon Energy Corporation will be the subject of a separate process and subject to budget approval.

6.0 ACKNOWLEDGEMENT

The Corporation thanks all those who respond to this RFI.

TOPIC:

REFERENCE: Page 5 Re footnote 5:

"... provision for three initial LNG storage tanks (499.5 m3 for a total of 6 days storage) and the potential to add in future two additional smaller storage tanks (240 m3) to retain 6 days storage with the third gas-fired module."

PREAMBLE:

QUESTION:

a) Would there always be 6 days of storage for the first two gas-fired modules?

b) For the third gas-fired module?

c) What is the estimated cost of building "*two additional smaller storage tanks…*"? Is this cost included in the $4.4 million amount for the installation of the third gas-fired module referenced on page 4?

d) Are these additional tanks required to provide 6 days of storage for the first two gas-fired modules?

e) For the third gas fired module?

f) Are there any other LNG storage facilities in the Yukon that Yukon Energy would have access to? How much would this access cost?

g) Six days of storage seems to be a short period of time in case of emergencies like road closures, how did Yukon Energy determine that this was an appropriate amount of storage?

h) By comparison how many days of diesel storage is available at Yukon Energy's Whitehorse, Faro, and Dawson City diesel plant sites and in other commercial storage facilities in and around Whitehorse?

i) Diesel fuel can be transported by air if need be, but can LNG be transported by air?

j) Please confirm that under no circumstances would LNG or natural gas from the proposed storage and vapourization facilities be used for any purpose other than electricity generation by Yukon Energy. If not, please explain.

ANSWER:

(a), **(b)**, **(c)**, **(d)**, **(e)** and **(g)**

Please see YUB-YEC-1-6(a) and YUB-YEC-1-10(b) as regards LNG storage capacity and YUB-YEC-1-5(f) as regards highway closure and adequacy of storage.

(f)

Yukon Energy's facility would be the first LNG storage and vapourization facility in the Whitehorse area. At this time there are no other nearby storage and vapourization facilities that YEC would have access to. However, as noted, the Project's level of storage capacity is considered fully adequate at this time, given expected normal thermal generation load requirements even in winter (which are well below sustained operation of these modules at maximum daily capacity levels) as well as availability of ample back-up diesel generation.

(h)

Current diesel storage capacity at the WTGS includes one fuel tank (approximately 160,000 litres[1]). Assuming 22.5 MW of de-rated diesel capacity at the WTGS with an average fuel efficiency of 3.7 kW.h/litre, this storage approximates 1.1 days operation at full capacity.

As noted in part (f) above, this diesel generation and related storage will remain available and will supplement the gas-fired generation and related LNG storage being

[1] Two additional double walled, horizontal diesel fuel storage tanks were available on site during the period when the Faro mine was in operation (providing a total additional 100,000 litres of storage on site). After the Faro mine shut down one tank was moved to Dawson and the other tank was moved to Mayo.

added to Yukon Energy's complement of hydro, thermal and wind generation on the Yukon grid.

There is approximately 113,000 litres storage available at Faro (2.2 days[2]) and 135,500 litres of storage available at Dawson (5.3 days[3]).

Yukon Energy cannot comment on diesel storage capacity present in other commercial storage facilities in Whitehorse.

(i)

Yukon Energy is not aware of LNG transport being undertaken by air.

The Project scope does not consider transportation of LNG by air – as indicated above, the level of storage capacity is considered fully adequate at this time, given expected normal thermal generation load requirements even in winter (which are well below sustained operation of these modules at maximum daily capacity levels) as well as availability of ample back-up diesel generation.

(j)

Yukon Energy intends to use the LNG storage and vapourization facilities for electricity generation for the Yukon grid. At this time YEC has not considered options where others could have access to YEC's vapourization unit. Any coordination option considered by YEC would retain full reservation of units as required to meet YEC requirements on a first priority basis.

See also response to YUB-YEC-1-5(d).

[2] Assuming 8 MW of de-rated diesel capacity with an average fuel efficiency of 3.8 kW.h/litre.
[3] Assume 3.95 MW de-rated diesel capacity with an average fuel efficiency of 3.72 knWh/litre.

TOPIC:

REFERENCE: Page 6

"... iii. Blackstart power capability for the natural gas-fired generating units ..." and Footnote 6

PREAMBLE:

QUESTION:

a) The wording of these sections implies that a blackstart generator unit will not actually be located at the LNG facility, is this correct? If there is no blackstart generator to be located there, please explain why not.

b) Please explain why blackstart capability is required.

c) How long will it take to start the proposed LNG generators from a cold start with a blackstart generator?

d) If a blackstart generator is not located at the Project how long will it take to bring one there, connect it, and start it?

e) Please explain why LNG is an appropriate emergency back-up source of power if it is dependent on an external heat source to get it started. Please expand on Yukon Energy's definition of flexibility and reliability is in this context.

ANSWER:

(a)

Due to close proximity of the facility to the existing S150 substation, station service power is assumed to have high reliability, hence onsite blackstart generator is not deemed essential. Following a disturbance event, station service at the proposed facility will be restored within 30 minutes, thereby ensuring station service power would be available at the proposed LNG facility. In event of a sustained loss of station service

power, a small, mobile generator will be available to restore station service power at the proposed facility within 2 hours.

(b)

Blackstart capability is not required due to the high availability of station service to the site.

(c)

System is designed to ensure vaporization and natural gas generators are fully operational in less than 30 minutes.

(d)

In the event of an outage, YEC would follow its restoration procedure and power would be restored at the proposed LNG power within 30 minutes. Use of the generator would only occur should there be issues with the transformer at the proposed substation or with the distribution line linking the existing S150 and the proposed S151 substations. In event of a sustained loss of station service power, a small, mobile generator will be available to restore station service power at the proposed facility within 2 hours.

(e)

Thermal generation is flexible and reliable in the context of comparison with other available options, i.e., thermal generation can be operated flexibly and reliably when required by relying on energy stored at the station site (compared to options where energy supply is not so reliable or flexible), and has a low capital cost (relative to capital intensive renewable options) such that it is not necessary to operate at high use levels on a sustained basis in order to be cost effective.

Thermal generation from natural gas or diesel is required to provide reserve capacity for the isolated Yukon grid in order to meet emergency back-up requirements (e.g., N-1 event), as well as grid peak loads during winter months and other periods when water availability for hydro generation is limited by seasonal or drought conditions or is otherwise insufficient to meet grid load requirements. Thermal generation to meet this range of expected loads conditions will be capable of operating on an intermittent

and on a sustained basis. Based on the projected use of the natural gas fired engines, YEC deems it meets the reliability and flexibility criteria defined in the 20-Year Resource Plan.

TOPIC:

REFERENCE: Page 6 Item 4. c.

"...future conversion of existing engines to fuel blend (diesel and natural gas), and / or future installation of new gas or dual fuel engines at the existing WTGS...".

PREAMBLE:

QUESTION:

a) Has the vapourizing equipment specified in the proposed Project been sized to satisfy the needs of the entire existing WTGS converted to natural gas generation including dual fuel conversions and including potential new gas engines in the space of the two Mirrlees units to be decommissioned?

b) If the proposed Project, including the third generating unit and two smaller storage tanks, is undertaken would Yukon Energy expect to use the LNG storage and vapourization for the proposed Project only, or would additional LNG storage and / or vapourization capacity be required for any future dual fuel conversions of other diesel generators in the existing diesel plant or natural gas-fired generator additions to the existing diesel plant?

c) If additional vapourization and storage is not, in Yukon Energy's estimation, required, please provide the number of days of operation of the existing WTGS converted to dual fuel plus the gas generators proposed in this project that could be sustained from the LNG storage in the proposed project.

d) If additional LNG storage and vapourization facilities are required, please provide the capital cost estimates for these facilities and explain where they will be physically located.

ANSWER:

(a) through **(d)**

Please see response to YUB-YEC-1-6(a, c, and d), YUB-YEC-1-10(b), and CW-YEC-6(b) for information currently available on these matters.

TOPIC:

REFERENCE: Page 7

"Yukon Energy is undertaking all required planning ... to obtain authorizations and approvals necessary to allow construction of the Project to commence in early May 2014 to meet the in-service target of late 2014 ...", and page 11.

PREAMBLE:

QUESTION:

a) What is the capital cost premium that will be paid for such an accelerated construction period? Please provide an itemized list.

b) Please detail Yukon Energy's contingency plan in the event that approvals and permits are not in place to enable construction to commence in time to complete the Project for the winter of 2014-2015?

c) Please confirm that if Yukon Energy had placed an order for Caterpillar 3616 diesel generators at the time the LNG generators were ordered in Q2 2013 (at the time the LNG generators were actually ordered) the new diesel generators could have been operational for the 2014-2015 winter.

d) What is the date of the order for the GE J624 gas generators?

e) What permitting would have been required for such a like-for-like diesel replacement project? Could a YESAB application and a YUB Part 3 proceeding have been avoided? If not please explain why not?

ANSWER:

(a) and **(b)**

The import of the above-reference quote (at Page 7 of the Application) is that Yukon Energy is undertaking all of the required activities necessary to allow construction of the

Project to commence in May 2014 and to meet the in service target date of late 2014 for the first two natural gas-fired units. The document describes this as the planned construction period, not an accelerated construction period.

The response to YUB-YEC-1-2(a) and (b) addresses the financial impacts to YEC or its customers, beyond the lost ratepayer savings estimated in the Application, due to delays in commencing construction and meeting the targeted in service date. Yukon Energy is working towards ensuring the start of construction in May 2014 (and in service prior to the end of 2014) to ensure that these potential financial impacts are avoided. WD1 and WD2 will remain connected until the new gas units can be securely commissioned and brought into service.

(c)

YEC cannot confirm what is requested. Aside from not having investigated issues related to ordering a new Caterpillar 3616 diesel engine for the WTGS, there are many other issues that would need to be addressed to confirm a feasible schedule for decommissioning and installation of new diesel engines within existing areas of the WTGS. See UCG-YEC-1-5 for elaboration of issues noted from the RFI and preliminary engineering activities.

(d)

An interim commitment was undertaken in late May 2013; formal agreements and payments occurred during the summer of 2013. The contract signing date was September 18, 2013.

(e)

There is no basis to assume a YESAB Project Proposal and a YUB Part 3 proceeding could have been avoided if a like-for-like diesel replacement project has been proposed rather than the Project with conversion from diesel to gas.

Projects are designated as “regulated projects” under Part 3 of the *Public Utilities Act* by specific direction of the Yukon Government. Yukon Energy cannot comment on the internal processes of the Yukon Government that may lead to a designation of an energy

Project pursuant to the Act, but YEC has no basis to assume that a Part 3 Application would not occur.

Similarly, a YESAB review would be anticipated to be required for any installation of new generation and the triggers for Executive Committee in this instance are based on capacity of the new generation (rather than any fuel-related factors).

TOPIC:

REFERENCE: **Page 7 and footnote 7 regarding the proposed new double trailer A-Train trucks**

PREAMBLE:

QUESTION:

a) Are the proposed trucks (either the A-Train or the alternative) powered by LNG engines? If not please explain what is being done with the boil-off gas during the time of the transport.

b) Please provide an update of the progress with respect to licensing these new trucks in BC and Alberta, and with their fabrication.

c) Is Yukon Energy now the only party that is actively involved in this truck development project? If not, please indicate who the other parties are and discuss whether their participation is slowing the progress of the licensing or the fabrication of these new trucks.

d) If necessary can Yukon Energy do this LNG truck project on its own and if so what are the cost and/or other implications?

e) Please provide Yukon Energy's statutory authority for this type of activity.

ANSWER:

(a)

The proposed trucks are not powered by LNG engines. Tanker design for any LNG haul option addresses all requirements related to LNG transport, including retention of boil off gas.

(b) and **(c)**

Please see response provided to YUB-YEC-1-5 for an update regarding licensing and procurement of the A-Train trailers and coordination of shipping activities with other parties. Working with other parties is not slowing the process.

(d) and **(e)**

Yukon Energy expects to contract with a trucking firm for the LNG truck haul. YEC will examine potential options for ownership of A-Train units to be used by YEC, including ownership by the selected LNG transport service contractor, or ownership by YEC, to determine what yields best value to YEC. For further detail please see response to YUB-YEC-1-5. Precedent for options in this regard exists with NT Energy who has contracted a firm to haul LNG from Vancouver to Inuvik using new Tridem units that were modified and fabricated for the NT Energy requirements.

Yukon Energy currently contracts for trucking of diesel fuel to Whitehorse to meet its generation requirements and is not aware of any additional statutory authority required in this regard for trucking of LNG fuel to Whitehorse for the same purpose.

TOPIC:

REFERENCE: Page 8 Table 3-1

PREAMBLE:

QUESTION:

a) Please provide a Table similar to Table 3-1 but adding to it the following columns: (1) a column for actual in-house expenditures to January 31, 2014; (2) a column for actual third party expenditures to January 31, 2014; (3) a column for actual and projected in-house expenditures to April 15, 2014; and (4) a column for actual and projected third party expenditures to April 15, 2014.

b) What are the input and output voltages of the substation module and what is its capacity?

c) Please provide a breakdown of the $2.5 million grid connection costs into (1) the substation module; (2) the power line to the S150 substation; and (3) modifications within substation S150.

d) (Also reference pages 11, 12, and 13.) Please provide a detailed list of the firm commitments (e.g. contracts) Yukon Energy has made to date for various goods and services for the LNG project. Please include in this list any additional firm commitments Yukon Energy will have entered into between the response date to the above and April 15, 2014.

e) Please provide a list of non-recoverable in-house expenditures and third party penalties/costs that Yukon Energy would be subject to should the LNG project be cancelled with the exception of the acquisition of the property for the proposed LNG Project.

f) Please provide Yukon Energy's cost estimates (in house and third party listed separately) for each of the YESAB assessment process and for the YUB Part 3 proceeding.

g) Please list the costs that would be involved in the acquisition of the property where the proposed LNG project would be sited.

ANSWER:

(a)

Please see Table 1 below.

Table 1:
Actual and Projected Expenditures

	Estimated Costs ($ Million)				
Project Component	May 2013 Estimate	Costs Incurred to Jan 2014	Feb-Apr 2014 (estimate)	Post April 2014 (Estimate)	Revised Estimated Cost
Planning Costs - 3rd Party	2.0	1.5	0.2	0.1	1.8
Planning Costs - In-house	0.4	0.7			0.7
Engineering Services	1.5	0.6	0.5	0.3	1.4
Project Management	1.0	0.4	0.3	1.4	2.1
LNG Storage - EPC Contract	4.6	0.0	2.4	4.3	6.7
LNG - Site Development	5.5	-	-	7.8	7.8
LNG Gen - Engines	11.4	8.6	.5	1.7	10.9
Grid Connection	2.5	-	0.1	1.9	2.0
Owners Costs - 3rd Party	1.8	0.2	0.1	1.0	1.3
Owners Costs - In-house	1.9	0.2	0.2	0.8	1.1
BOP - Preliminary Assessment	0.3	-	-	-	-
BOP - Decommissioning	1.4			0.6	0.6
Total	**34.4**	**12.2**	**4.5**	**19.8**	**36.5**

(b)

The GE Engines generate power at a voltage of 4.16 kV. The voltage will be increased to the 34.5 kV, consistent with distribution voltage used at the existing S150 substation. The transformer to be installed in the new substation has a maximum capacity of 15 MVA.

(c)

Please see Table 2 below which provides estimated costs for the grid connection. Please note that this table includes costs consistent with the presentation of updated costs in YUB-YEC-1-1(d) and reflects the realignment of costs as part of the process of aligning the scope of work into contracts.

Table 2:
Grid Connection Costs

		Original Estimate	Reallocated	Revised Estimate
S151 to S150 Substation Connection				
Materials		623,312		623,312
Civil/Electrical/Mechanical		960,000		960,000
Engineering	1	100,000	(100,000)	-
YEC Labour	2	85,000	(85,000)	-
Connect E-house to Gas Plant & Generators	3	200,000	(200,000)	-
S151 - LNG Substation		1,968,312	(385,000)	1,583,312
Materials		150,000		150,000
YEC Labour	2	52,000	(52,000)	-
S151 to S150 Powerline		202,000	(52,000)	150,000
Materials & Contractors		300,000		300,000
YEC Labour	2	40,000	(40,000)	-
S150 modifications		340,000	(40,000)	300,000
Estimated Grid Connection Cost		2,510,312	(477,000)	2,033,312

1 Included in Engineering Scope of Work
2 Included in YEC Labour estimate
3 Moved to Site Development contract

(d) and **(e)**

Referencing YCS-LE-YEC-1-11(a) the costs incurred to the end of January 2014 equal $12.2 million. During the period of February to April an additional $4.5 million will be expended to maintain project schedule and equipment delivery dates. Of the $16.7

million forecast to be expended by YEC by the end of April 2014, the main contract amounts are as set out in Table 3 below.

Please also see response to YUB-YEC-1-2(c) with regard to assessment of cost impacts of cancellation of the Project.

Table 3:
Main Contractual Commitments to January and to April 2014

Contractual Commitments	To Jan 2014	Feb-April 2014
Project Management	345,000	330,000
Detailed Engineering	499,778	500,000
Generation Modules	8,620,717	557,513
Storage Tanks		743,120
LNG Storage Equipment		1,678,598
34.5 kV transformer		110,194
Total	**9,465,495**	**3,919,425**

(f)

Forecast costs related to the YESAB permitting process are set out in Table 4 below. Please note these costs do not include any contingencies for mitigation costs which may arise to comply with any YESAA licensing recommendations for the Project (no such costs are expected).

Table 4:
YESAB Cost Estimate

Activity	3rd Party	In-house	Grand Total
Baseline	465,152	91,630	556,781
Application	124,828		124,828
Review Process	68,457	32,157	100,614
Grand Total	**658,437**	**123,787**	**782,224**

The Part 3 hearing cost estimate is provided in Table 5 below. This estimate generally reflects actual costs incurred for the Mayo B Part 3 hearing process. It is expected that Part 3 hearing costs will be reviewed in detail by the Board and other intervenors as part of YUB's Cost Award Process and further details may be provided at that time.

Please note that costs related to the YUB Part 3 review process will be deferred to the Hearing Cost Reserve Account, and as such are not included in the updated detailed Project cost estimates reviewed in YUB-YEC-1-1(d), and were also not included in the estimated costs as originally filed in the Application (the Part 3 requirement was not anticipated at that time).

Table 5:
Part 3 Hearing Cost Estimate

YEC - Consulting & Legal	180,000
YEC – Hearing Costs	37,500
YUB & Interveners	182,500
Estimated Part 3 Costs	**400,000**

(g)

The estimated cost of the land purchase is $151,000.

TOPIC:

REFERENCE: Page 8

"...Yukon Energy does not at this time have firm pricing for the third GE natural gas-fired generating unit – the $4.4 million estimate continues to be the best available information at this time."

PREAMBLE:

QUESTION:

a) Is the $4.4 million estimate for the third GE J 624 natural gas-fired unit the installed cost including all planning, engineering, project management, owner's costs etc.?

b) Does the $4.4 million include the purchase and installation of the additional LNG storage tanks referred to in Footnote 5 on page 5 of the Application? If not what is the estimated installed costs (all costs inclusive of owner's costs) for these additional storage tanks?

ANSWER:

(a)

Please see response to YUB-YEC-1-12(c) and (d).

(b)

Please see response to YUB-YEC-1-6(a).

Costs for the additional two 120m^3 storage tanks are not included in the cost for the third engine. The Application addressed the potential to add in future at least two additional smaller storage tanks (total 240 m^3) on the site if it was decided in future that YEC wanted to retain a minimum of six days storage when three engines are installed;

however, neither these nor any other potential additional storage capacity that could be located on the site are included in the business case to be reviewed at this time.

TOPIC:

REFERENCE: Page 9

"... As the thermal generation units at Whitehorse are expected to be relied upon on an increasing basis on the integrated grid, deferring replacement of these units would expose all grid customers to unreliable generation capacity ..."

PREAMBLE:

QUESTION:

a) Is it Yukon Energy's assertion that all existing diesel generation capacity in Whitehorse is unreliable? Why or why not?

b) Are the Mirrlees units #1 and #2 required for any condition other than the N-1 (emergency) planning criteria?

c) What is the magnitude of this risk – in the last 20 years how many hours has the Aishihik power plant and or transmission line been completely unavailable on an unplanned basis?

d) What is Yukon Energy's view of the reliability of the diesel generation capacity in the Faro and Dawson City diesel plants?

e) Are the Mirrlees units #1 and #2 that are proposed to be retired listed as first and second in the stacking order for diesel generation units to be run when diesel capacity is needed on the grid? If not where are they in the stacking order?

f) Does Yukon Energy's reference to being 'relied upon on an increasing basis' indicate that Yukon Energy believes that diesel generation will in effect become a base load or base load like in the near future? If so please indicate when (in what year or at what level of annual energy), in Yukon Energy's view, peaking load becomes more base load-like.

ANSWER:

(a) through **(f)**

The Application sets out the need for the Project based on YEC's existing capacity planning criteria, forecast loads, and scheduled retirements. Diesel units on the grid are required for reliable and flexible capacity – the extent to which each unit is operated depends on its stacking order as well as specific conditions leading to required diesel operation. YEC is not reviewing in this proceeding its capacity planning criteria, the magnitude of the related risks, the reliability of each of its thermal generation stations, or distinctions between different types of diesel generation loads that may occur. YEC is very aware that Yukon's grid is isolated and needs to be planned for reliable generation to meet peak winter non-industrial load requirements under an N-1 event (which currently is loss of transmission from Aishihik to Whitehorse, an event which in fact occurred within the last decade).

The Mirrlees units are not listed first in the stacking order (they are near the end of the stacking order of thermal generating units at the WTGS). WD7, WD6, WD5 and WD4 are before WD1 and WD2 in the stacking order.

TOPIC:

REFERENCE: Page 9 and Figure 3-1 on page 10.

PREAMBLE:

QUESTION:

a) Please provide the Excel spreadsheets (with the formulae intact) that yield the projected capital and O&M savings.

b) Please provide a comparative analysis for a diesel project alternative having the same fuel efficiency as the proposed diesel alternative but costing $5 million less, i.e. $28.6 million.

c) Please provide a comparative analysis for a diesel project alternative having the same fuel efficiency but costing $10 million less, i.e. $23.6 million.

d) Please list the LNG costs on a per unit volume basis (m^3 or MMBtu) and on a per kWh basis in each of the years 2015 through 2020, based on long term average water and base case load forecast, including:

   i. Natural gas purchase;
   ii. Natural gas liquefaction;
   iii. Transport (including premiums for spring load restrictions and for the smaller volumes required as discussed on Page 38 of the Application); and

e) Please confirm that all the projected savings as set out on page 9 are based on average water conditions.

f) Please provide details of the O&M costs (operations, maintenance (including labour in each), property insurance, and any other fixed costs).

g) Does Yukon Energy have long term fixed price contracts for all of natural gas purchase, natural gas liquefaction, and LNG transport? If so please provide

copies of these contracts and if not please explain why not and the risks associated with the lack of contracts.

ANSWER:

(a)

Please see UCG-YEC-1-2 Attachment 1 for the Excel version of Figure 3-1 and supporting calculations in Table 4-3 with formulae intact.

(b) and **(c)**

Please see YCS/LE-YEC-1-14(b) Attachment 1 for the analysis with $5 million (14.86%) and $10 million (29.72%) lower new diesel capital costs.

Under $5 million lower cost scenario the estimated ratepayer savings are at $1.0 million in 2015 compared to $1.3 million as shown in Figure 3-1 of Application, $1.8 million (compared to $2.2 million) in 2016, $2.2 million (compared to $2.6 million) in 2017 and $2.7 million (compared to $3.1 million) in 2018.

Under $10 million lower cost scenario the estimated ratepayer savings are at $0.7 million in 2015 compared to $1.3 million as shown in Figure 3-1 of Part 3 Application, $1.4 million (compared to $2.2 million) in 2016, $1.8 million (compared to $2.6 million) in 2017 and $2.4 million (compared to $3.1 million) in 2018.

(d)

The Application provides the level of detail on LNG delivered costs that is available at this time and/or is not confidential to suppliers. These costs on a per unit basis were not varied by year in the Application's analysis. In summary, the following have been provided in the Application (costs per kW.h assume 40% engine conversion efficiency):

- Delivered cost of 13.5 cents/kW.h ($15.8/MMBtu)
- Natural gas cost assumed at $4.5/MMbtu (3.8 cents per kW.h)
- LNG haul from Calgary at 4.4 cents/kWh with A-Train ($5.2/MMBtu)
- Assumed liquefaction costs at $6.2/MMBtu (5.3 cents/kW.h).

Please also note response to YUB-YEC-1-44 for updated LNG haul cost estimates.

(e)

Analysis regarding net ratepayer cost savings assumes default diesel requirements under long term average water conditions under Base Case grid load forecasts (with no Alexco after fall 2013) as detailed in Appendix C of the Application.

(f)

The Application assumes that there is no material difference in non-fuel O&M costs as between the new diesel option and the Project. For example, response to YUB-YEC-1-7(i) confirms that annual insurance premiums will be basically determined on the same basis for both options.

(g)

Aside from the five year Shell contract (which is confidential), Yukon Energy does not currently have long term fixed price contracts for natural gas purchase, natural gas liquefaction or LNG transport.

For further details and updates regarding natural gas purchase and liquefaction please see response to YUB-YEC-1-4, including near-term contingency plans related to supply from Shell's proposed plant at Jumping Pound.

For further details and updates regarding LNG transport please see YUB-YEC-1-5. YEC plans to proceed with an RFP process for an appropriate contract for LNG transportation, once the Project is approved.

TOPIC:

REFERENCE: Page 9 and footnote 9

PREAMBLE:

QUESTION:

a) Please provide the manufacturers' information (e.g. operating hours between overhauls, and number of overhauls to recommended retirement) and other information as well as Yukon Energy's calculations that justifies a 40 year depreciation for each of:

   i. The LNG storage facility;
   ii. The LNG vapourization facility; and
   iii. The GE natural-gas fired generators.

b) What variable O&M costs in $ per kWh are assumed/projected for each of the new diesel facility and the LNG Project (including storage, vapourization, and engines)?

c) Given that LNG would be a new venture for Yukon Energy please indicate the sources for the LNG O&M cost projections.

ANSWER:

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

The details on manufacturers' information requested is under discussion and not available at this time.

As reviewed in response to UCG-YEC-1-14(f), the Application assumes that there is no material difference in non-fuel O&M costs as between the new diesel option and the Project; details on potential specific O&M costs as requested are not available at this time.

With regard to 40-year depreciation assumed for the Application, please see response to YUB-YEC-1-52(a).

TOPIC:

REFERENCE: Page 10 to page 13 Re LNG truck transport

PREAMBLE:

QUESTION:

a) Please provide a copy of the RFP or RFEI (or other process if not one of these) by which Yukon Energy selected PROLOG to pursue LNG trucking options, and please provide their terms of reference.

b) Please list the firms that responded and explain why PROLOG was selected.

c) (Page 13) Please provide a copy of the RFP that Yukon Energy has issued for the design and fabrication of A-Train LNG hauling trucks.

d) Please list the firms responding and which Yukon Energy has selected and explain why.

e) Please provide copies of the RFP, RFEI, or documentation from another process if not one of these, from which Yukon Energy has selected Tridem to be an alternate trucking firm.

f) Please list the firms responding and explain how Tridem was selected.

ANSWER:

(a) and **(b)**

There was no RFP or RFEI to select PROLOG to pursue LNG trucking options. As reviewed in YUB-YEC-1-5(a), YEC participated with Western Copper and Gold in retaining PROLOG, based on this firm's expertise in providing strategic planning for infrastructure projects and logistics operations in the north.

(c) and **(d)**

Please see response to YUB-YEC-1-5(c), (g), (j), (k), and (l) regarding Yukon Energy's plans to design and develop the A Train units.

(e) and **(f)**

Tridem is not a trucking firm. Page 7 of the Application notes it is a currently available type of transportation unit with a 54,000 litre capacity that may be used initially if there are delays in the licensing and/or fabrication of the new A-Train units.

Please see response to YUB-YEC-1-44 for an update on Tridem units as currently being used for NT Energy LNG haul from Vancouver to Inuvik.

TOPIC:

REFERENCE: Page 10

PREAMBLE:

QUESTION:

a) What is Yukon Energy's contingency plan in case the Jumping Pound LNG production facility cannot deliver LNG in the winter of 2014-2015?

ANSWER:

(a)

Please see response to YUB-YEC-1-4.

TOPIC:

REFERENCE: Page 11

"With development of more efficient operations with larger and more stable loads, the estimated A-Train delivery cost from Calgary is estimated to fall to 3.7 cents/kWh ..."

PREAMBLE:

QUESTION:

a) Please describe in detail what the "more efficient operations" are that are referenced here.

b) Please describe what is meant by "larger and more stable loads" and relate this to the LNG demand projected in the base case load.

ANSWER:

(a)

In effect, more efficient operations refer to operations that would improve the utilization of the A-Train units each trip. Please see response to YUB-YEC-1-5(d) for examples of coordination efforts with other parties that Yukon Energy is exploring in order to ensure more efficient operations to reduce operating costs for LNG transport.

Please see YUB-YEC-1-4 for updated information on LNG haul costs.

(b)

Larger and more stable loads simply refers to improved per trip utilization of the A-Train units. This may be due to increased YEC requirements for LNG in the near term or due to coordination of the use of the A-Train units with other interested parties.

Appendix C of the Application includes four scenarios to reflect the timing for connection or reopening of mines and the load update for non-industrial and existing mine loads. The economic analysis included in the Application is based on the most conservative

load scenario (Base Case with no Alexco after fall 2013). The economics of the Project (including the A-Train delivery costs) would improve under the other less conservative load scenarios considered under Appendix C (as there is a greater default diesel requirement).

TOPIC:

REFERENCE: Page 11 Re LNG storage tanks

PREAMBLE:

QUESTION:

a) Please provide copies of the RFP, RFEI, or tender documents, and copies of the relevant specifications that Yukon Energy used to solicit a supplier for LNG storage tanks.

b) Please list the firms responding and which was selected and explain why.

ANSWER:

(a)

Please see response to YUB-YEC-1-29(a and b) for the general EPC tender process for all LNG facilities (including LNG storage tanks, vapourizer and other related equipment) and a review of outcomes of this tender, the cancellation of the tender based on the results, and the subsequent process of contractor selection.

(b)

The list of firms that responded is confidential and cannot be shared. The successful supplier is Taylor Wharton. Please see response to YUB-YEC-1-29 (a and b).

TOPIC:

REFERENCE: Page 11 Re Transformer

PREAMBLE:

QUESTION:

a) Please provide a copy of the RFP, or RFEI, or tender documents, and copies of the relevant specifications used to solicit supplier options.

b) Please list the suppliers that responded and indicate who the successful supplier is and why they were selected.

ANSWER:

(a)

Please see Attachment 1 to this response which provides the RFP complete with all specifications.

(b)

The list of firms that responded is confidential and cannot be shared. The successful supplier is Northern Transformer.



YUKON ENERGY CORPORATION
Attention: Procurement
#2 Miles Canyon Road,
Box 5920, Whitehorse, Yukon
Y1A 6S7
Phone: (867) 393-5335

REQUEST FOR QUOTATIONS
#2013-036

SUPPLY OF S151 STEP UP TRANSFORMER

Issue Date: March 12, 2013

YUKON ENERGY CORPORATION

TABLE OF CONTENTS

PART 1 OVERVIEW 3
1.1 CORPORATE OVERVIEW 3
1.2 PROJECT DESCRIPTION 3
1.3 SUPPLY OF TRANSFORMER 3

PART 2 INSTRUCTIONS / INFORMATION TO BIDDERS 5
2.1 LETTER OF INTENT TO RESPOND 5
2.2 DELIVERY OF QUOTATIONS - HARD COPY 5
2.3 DELIVERY OF QUOTATIONS - ELECTRONIC FORMAT 5
2.4 QUOTATION SUBMISSION 6
2.5 CLOSING DATE AND TIME 6
2.6 VERIFICATION OF RECEIPT OF QUOTATION 7
2.7 QUESTIONS 7
2.8 ADDENDA 8
2.9 QUOTATION WITHDRAWALS 8
2.10 AMENDMENTS TO QUOTATIONS 8
2.11 QUOTATION DETAILS 8
2.12 RIGHT OF ACCEPTANCE / REJECTION 8
2.13 NEGOTIATIONS 9
2.14 WAIVER 9
2.15 WAIVER OF IRREGULARITIES 9
2.16 AFFILIATION 9
2.17 INCURRED COSTS / EXPENSES 9
2.18 IRREVOCABILITY 10
2.19 CLARIFICATION 10
2.20 PUBLICITY 10
2.21 CONFIDENTIAL AND PROPRIETARY INFORMATION 10
2.22 NO COLLUSION 10
2.23 REFERENCES / CONTACTS 10
2.24 FULL DISCLOSURE 11
2.25 KNOWLEDGE OF WORK 11
2.26 LEGAL COUNSEL 11
2.27 BIDDER DEBRIEFING 11

PART 3 SCOPE OF WORK AND TIMELINES 12
3.1 SCOPE OF WORK 12
3.2 ANTICIPATED TIMELINE 12

PART 4 SUBMISSION REQUIREMENTS 13
4.1 GENERAL 13
4.2 PRICE 13
4.3 QUALITY ASSURANCE PROGRAM 13
4.4 TECHNICAL SUBMISSIONS 13

PART 5 EVALUATION..... 14

PART 6 SUMMARY 15

PART 7 LETTER OF INTENT AND QUOTATION FORMS..... 16

PART 8 SPECIFICATIONS..... 2

PART 1
OVERVIEW

1.1 CORPORATE OVERVIEW

Established in 1987, Yukon Energy Corporation (the "**Corporation**") is a publicly-owned electrical utility that operates as a business, at arms length from the Yukon Territory Government. The Corporation is the main generator and a transmitter of electrical energy in the Yukon Territory and works with its parent company Yukon Development Corporation to provide Yukon Territory residents with a sufficient supply of safe, reliable electricity, and related energy services.

The Corporation is regulated by the *Business Corporations Act* (Yukon), the *Public Utilities Act* (Yukon), and the *Waters Act* (Yukon). The Corporation's headquarters are located near the Whitehorse Rapids hydro plant in Whitehorse with community offices in Mayo, Faro and Dawson City.

Additional Corporation information and annual reports can be viewed on the Corporation's website at: http://www.yukonenergy.ca.

1.2 PROJECT DESCRIPTION

Background

Yukon Energy is installing a new natural gas generating plant near its existing Whitehorse facilities. The generating plant will operate at a nominal 4.16 kV, and connect into the Yukon Energy grid via a 34.5 kV distribution line.

To make the connection between the generating plant and the distribution line, a new substation will be installed adjacent to the generating plant. The substation is designated S151, and will include a generator step-up transformer to interface between the generating plant and the distribution system.

This specification describes the quality, material, and workmanship requirements for the design, fabrication, assembly, testing, and delivery of the generator step-up transformer.
.

1.3 SUPPLY OF TRANSFORMER

The Corporation is issuing this Request for Quotations (the "**RFQ**") for the purpose of obtaining quotations (collectively, the "**Quotations**", and individually a "**Quotation**") for the supply and delivery of one (1) 4.16-34.5 kV, 9/12/15 MVA generator step-up transformer.

The transformer shall be complete with all components, auxiliary equipment, controls, instrumentation, and other minor items not specifically referred to, but essential for the safe, efficient, and reliable installation, testing, commissioning, operation, and maintenance of the equipment.

The S151 Substation will be located at Yukon Energy's Whitehorse generating station in Whitehorse, Yukon. The selected bidder (the "**Vendor**") will be responsible for the design, manufacture, testing, inspection, and delivery of the Transformer (as defined in Section 3.1), as more specifically set out in Part 3 of this RFQ and the Specifications. An anticipated schedule for the Work (as defined in Section 3.1) is provided in Section 3.2.

PART 2
INSTRUCTIONS / INFORMATION TO BIDDERS

2.1 LETTER OF INTENT TO RESPOND

After reviewing this RFQ, the Corporation requests that all potential Bidders who intend to respond to this RFQ identify themselves using the letter of intent to respond (the "**Letter of Intent**") provided in Part 7 of this RFQ. Only those companies / individuals submitting a Letter of Intent will receive subsequent information, addenda and Q&A information.

2.2 DELIVERY OF QUOTATIONS - HARD COPY

Quotations must be submitted on Quotation Form "1" and Quotation Form "2" (collectively, the "**Quotation Forms**") provided in Part 7 of this RFQ. For Quotations in hard copy, each form must be enclosed in a separate sealed envelope, and delivered in original form by hand or courier to:

Yukon Energy Corporation
Attention: Procurement
#2 Miles Canyon Road
Box 5920, Whitehorse, Yukon
Y1A 6S7

(the "**Corporation's Office**").

2.3 DELIVERY OF QUOTATIONS - ELECTRONIC FORMAT

The Corporation will accept Quotations submitted in electronic format, in accordance with this Section 2.3. If submitting a Quotation electronically, in order for the Quotation to be considered, the Quotation must:

(a) be identified and transmitted using two separate e-mails as follows:

(i) e-mail 1 will be sent to tenderform1@yec.yk.ca and will consist of Quotation Form 1 and all information other than Quotation Form 2 and other pricing information, and should be identified on the subject line as "Submission for RFQ #2013-036, Quotation Form 1"; and

(ii) e-mail 2 will be sent to tenderform2@yec.yk.ca and will consist of Quotation Form 2 and any associated pricing information and should be identified on the subject line as "Submission for RFQ #2013-036, Quotation Form 2";

(b) also be delivered in hard copy form to arrive as soon as possible after the Closing Date and Time and e-mail 1 must include shipment/courier details to assure the Corporation that the originally executed Quotation documents are in transit, including;

(i) the name of the courier company by which the original Quotation documents have been shipped; and

(ii) the courier company's document tracking number(s).

If there are discrepancies between the Quotation as submitted electronically and the hard copy Quotation received subsequently, the hard copy Quotation shall govern.

Bidder's sales literature and/or any information additional to that requested in this RFQ that the Bidder is including in its Quotation need not be included in the electronic Quotation submission, but should be included in the hard copy submission.

Bidders should note that it is their responsibility to ensure that electronic transmissions are free from all viruses. If the Corporation receives an electronic transmission that is infected with a virus or other electronic code that, in the sole opinion of the Corporation, is harmful to the Corporation's computer systems, the Corporation reserves the right to take any action as deemed necessary to disinfect the electronic transmission. The Corporation will not be liable for any changes that may occur to the electronic transmission, including rendering the transmission unreadable, as a result of the disinfecting process.

Bidders should note that the Corporation's e-mail system will not accept emails in excess of 10 MB. The Corporation prefers all attachments to be in PDF format. It is the responsibility of Bidders to ensure that e-mails are of a size that can be received by the Corporation and in a format that can be read by the Corporation.

2.4 QUOTATION SUBMISSION

A Bidder will clearly identify on the envelope containing the Quotation or in the first section of the first e-mail referred to in Section 2.3(a) the name and address, telephone and fax numbers of the Bidder, the name of the RFQ, the associated RFQ number, and the Closing Date and Time (as defined in Section 2.5).

Quotations submitted by hand or by courier should be submitted in **three** copies with Quotation Form 1 and Quotation Form 2 submitted in separate envelopes. One copy must be originally executed and include original signatures of duly authorized signatory(ies) of the Bidder. Quotation Forms submitted electronically must be submitted in accordance with Section 2.3, and must show that the original of Quotation Form 1 and Quotation Form 2 have been executed and include the signatures of duly authorized signatory(ies) of the Bidder.

Quotation Forms submitted via e-mail which do not comply with Section 2.3 or are submitted via fax or other non-original formats will not be accepted without the prior written consent of the Corporation, which consent may be unreasonably withheld.

2.5 CLOSING DATE AND TIME

The date and time of Quotation closing is:

November 22, 2013 at 4:00:00 p.m. Whitehorse local time
(as per the Corporation time clock located at the Corporation's reception area for Quotations delivered by hand or courier and as per the time when both e-mails have been received by the Corporation's e-mail server for Quotations delivered electronically)
(the "**Closing Date and Time**").

In order to qualify under this RFQ process, a Quotation must be received at the Corporation's Office on or before the Closing Date and Time. Quotations received by hand or courier after the Closing Date and Time will be rejected and will be returned to the Bidder unopened and time stamped. Quotations received electronically after the Closing Date and Time will be rejected, but will not be returned to the Bidder.

The Corporation may, in its sole discretion, from time to time and at any time on or before the Closing Date and Time, extend the Closing Date and Time by issuing a written addendum to all Bidders.

The Corporation assumes no risk, makes no guarantee, warranty or representation whatsoever and shall have no responsibility or liability whatsoever for and in connection with:

(a) the timely receipt of any Quotations or amendments to Quotations or any other information from any Bidder; or

(b) the working order, functioning or malfunctioning of the Corporation's e-mail system or any computer used in connection with this RFQ.

2.6 VERIFICATION OF RECEIPT OF QUOTATION

Bidders may verify that their Quotation has been received prior to the Closing Date and Time by calling (867) 393-5335. The Bidder must identify the Bidder's name before this information will be released. No other information concerning the Quotation will be released prior to the Closing Date and Time.

2.7 QUESTIONS

Bidders are required to submit their questions, including questions relating to specifications, discrepancies, omissions, or any apparent ambiguities, in writing, by fax or e-mail, prior to 4:00 PM PDT on the dates noted below for Q&A:

Yukon Energy Corporation
Attention: Matthew Sills (the "**Corporation's Representative**")
Telephone: (867) 393-5335 Fax: (867) 393-5301
E-mail: matthew.sills@yec.yk.ca

Bidders will not contact or ask questions of any other Corporation personnel. Information obtained from any person or source other than the Corporation's Representative cannot be relied on for the purposes of this RFQ process and cannot be incorporated into a Quotation. The Corporation may disqualify any Bidder who solicits information from any person other than the Corporation's Representative.

The Corporation will review the questions and where the information is not already provided, will issue an addendum to all Bidders under Section 2.8. Responses may be made up to 48 hours prior to the Closing Date and Time. The Bidder that submitted the question will not be identified in the Corporation's response.

To facilitate the question and answer process, the Corporation will use the schedule identified below for the receipt of questions and delivery of the Corporation's responses. The Corporation will make a reasonable effort to have the responses issued by the end of business on the Corporation's Response Date.

	Submission Date	Corporation Response Date
Q&A#1	November 8, 2013	November 12, 2013
Q&A#2	November 18, 2013	November 20, 2013

2.8 ADDENDA

The Corporation may amend or supplement this RFQ by addenda issued by the Corporation. All addenda will be in writing, sequentially numbered, and bear the date of issue. All addenda issued by the Corporation prior to the Closing Date and Time will become part of this RFQ. It is the sole responsibility of the Bidder, prior to the Closing Date and Time, to ensure that it has received all addenda pertaining to this RFQ. Bidders should acknowledge receipt of all addenda in Quotation Form 1.

2.9 QUOTATION WITHDRAWALS

Quotations may be withdrawn at any time prior to the Closing Date and Time by submitting a written withdrawal request to the Corporation's Office or by e-mail to the address given in Section 2.7. A Quotation that has been submitted by hand or by courier will be returned to the Bidder unopened and a Quotation that has been submitted electronically will be withdrawn, but not returned to the Bidder.

2.10 AMENDMENTS TO QUOTATIONS

Where a Quotation has been received by the Corporation before the Closing Date and Time, amendments by fax or e-mail are acceptable, provided that such amendments are sent to the number or address given in Section 2.7 and are received at that number or address prior to the Closing Date and Time.

Amendments to a Quotation must clearly state the name of the Quotation, the Closing Date and Time, and the name and address of the Bidder in accordance with this RFQ. Any amendment must be duly signed by an authorized signatory of the Bidder.

Any amendment to the Quotation price will state only the amount by which the Quotation price is increased or decreased and will not indicate the revised total Quotation price.

2.11 QUOTATION DETAILS

Bidders must provide complete and accurate information and details for all aspects of their Quotation. Failure to respond to any requests for information, costs or qualifications will be deemed to be a negative response, and may, at the sole discretion of the Corporation, disqualify the Quotation.

2.12 RIGHT OF ACCEPTANCE / REJECTION

The Corporation, in its sole discretion, may, at any time prior to selection of the successful Bidder, cancel this RFQ. No act of the Corporation, other than a notice in writing signed by the Corporation's Representative, will constitute an acceptance of a Quotation.

From the information submitted under this RFQ, the Corporation will determine the successful Quotation, which in the sole judgment of the Corporation, provides the best value to the Corporation in accordance with the requirements and criteria set out in this RFQ.

This RFQ is not an offer by the Corporation to enter into an agreement for the Work. The Corporation is not bound to enter into an agreement with the Bidder that submits the lowest price or fee structure, or with any Bidder. The Corporation is under no obligation to receive further information, whether it is oral or written, from any Bidder.

2.13 NEGOTIATIONS

Notwithstanding any other provision in this RFQ, the Corporation may in its sole discretion at any time and from time to time after submission of Quotations and before an agreement is entered into negotiate any terms and conditions of an agreement for the Work, including negotiating terms and conditions that are or may be different from those contained in this RFQ, with one or more Bidders, but not necessarily with all Bidders. The Corporation also reserves the right not to enter into negotiations with one or more Bidders; to terminate negotiations with any Bidder; not to offer the same or substantially the same negotiated terms and conditions of an agreement to more than one Bidder; and to award an agreement by acceptance of any Quotation so negotiated. If the Corporation selects a Quotation the Bidder will enter into an agreement with the Corporation

The opening of Quotations will be closed to the public. Information on Bidders' names or prices received may be released at the Corporation's sole discretion. If Bidders' names or prices are released, this information may be released only to qualifying Bidders after responses are opened and an agreement is awarded to the successful Bidder.

2.14 WAIVER

In consideration for the Bidder being permitted to participate in this RFQ process, the Bidder, by submitting a Quotation, agrees that it will not make a claim against the Corporation, for whatever reason, relating to the Quotation or this RFQ, and agrees that it waives and hereby releases the Corporation from any claim or recovery for costs, expenses, or damages incurred by a Bidder in preparing its Quotation, loss of profits, or any other matter whatsoever if no Transformer supply agreement is entered into with the Bidder. The Corporation will have no liability to any of the Bidders as a result of this RFQ.

2.15 WAIVER OF IRREGULARITIES

The Corporation may, in its sole discretion, waive any minor irregularity or non-compliant issues in the Quotations received. Failure to comply with any item(s) of this RFQ may result in the rejection by the Corporation, in the Corporation's sole discretion, of all or part of any Quotation.

2.16 AFFILIATION

Bidders will disclose any business relationships that may impact the Project or any component of the Work, including but not limited to subcontractors, joint ventures, or partnerships.

2.17 INCURRED COSTS / EXPENSES

Bidders are solely responsible for their own costs and expenses in preparing and submitting a Quotation and for any subsequent negotiation costs and expenses with the Corporation, if any. If the Corporation cancels this RFQ or rejects all Quotations, the Corporation will not be liable to any Bidder for any costs or expenses of preparation or presentation of their Quotation.

2.18 IRREVOCABILITY

After the Closing Date and Time, Quotations will be irrevocable and may not be amended for a period of ninety (90) days (the "**Irrevocable Period**"), and a Bidder will not revoke its Quotation until the expiry of the Irrevocable Period.

2.19 CLARIFICATION

The Corporation may at any time seek clarifications of, or any additional information in connection with, or modifications of, any Quotation from any one or more Bidders, but not necessarily all Bidders, either serially or concurrently, and in any manner including through written correspondence, interviews, or presentations by Bidders.

Any clarifications, additional information, or modifications received may form part of a Bidder's Quotation and may be considered by the Corporation, in its sole discretion, in its RFQ evaluation and decisions including without limitation as to acceptance, rejection, negotiation, or award, and the Corporation may accept any Quotation as clarified, supplemented, or amended through this RFQ.

2.20 PUBLICITY

The Bidder will not issue any press release or make any public announcement or disclosure concerning this RFQ, the Quotation, or the transformer supply agreement, without the prior written consent of the Corporation, which consent may be unreasonably withheld.

2.21 CONFIDENTIAL AND PROPRIETARY INFORMATION

This RFQ and all Quotations are the property of the Corporation, and all Bidders will keep confidential and will not use, reproduce, or distribute any information, drawings, or specifications included in or provided with this RFQ except for the purpose of preparing a Quotation. Each Bidder will clearly identify any information or records that it is providing in its Quotation that constitutes confidential information.

2.22 NO COLLUSION

Bidders will not discuss or communicate, in any form, with any other Bidder or any representative or agent of any other Bidder regarding the preparation or presentation of their Quotation. Quotations will be submitted without any connection, knowledge, comparison of information, or arrangement, with any other Bidder or any agent or representative of any other Bidder.

If a Bidder contemplates using the same subcontractor or supplier as another Bidder for a particular part of the Work, the Bidder will put into place appropriate ethical walls and other safeguards to protect the confidentiality of their information and to ensure collusion does not take place.

2.23 REFERENCES / CONTACTS

Bidders authorize the Corporation to contact any identified clients (current and past) and references regarding the information provided in their Quotation.

2.24 FULL DISCLOSURE

Bidders will provide a written statement of full disclosure addressing the following particulars:

(a) any personal relationship to any employee of the Corporation who makes recommendations concerning the award of a transformer supply agreement, or any employee (or immediate relative of an employee) of the Corporation with any direct, or indirect pecuniary interest, ownership or directorship with respect to the Bidder;

(b) any business relationship with the Corporation, any of its staff, employees, officers, directors, or board members;

(c) any matter involving a dispute with a claimed value in excess of $50,000 which is the subject of any current, pending, or threatened mediation, arbitration, or litigation proceeding; and

(d) particulars of any proceedings involving the Bidder under the *Bankruptcy and Insolvency Act* (Canada), the *Companies' Creditors Arrangement Act* (Canada) or similar legislation.

Bidders must specifically address the requirements of this Section 2.25 in their Quotation by either providing appropriate disclosure or by indicating that they have nothing to disclose in respect of the matters listed above.

Bidders must advise the Corporation's Representative in writing of any change in the foregoing throughout the RFQ process including any period up to and including the execution of the transformer supply agreement. The Corporation may reject any Quotation or terminate any resulting agreements without prejudice for failure to disclose the information required in this Section 2.25, or for disclosure at any time of proceedings in the nature of bankruptcy or insolvency by or against the Bidder.

2.25 KNOWLEDGE OF WORK

Bidders will inform themselves of the Work prior to submitting a Quotation. Bidders will make all investigations necessary to obtain full understanding as to the nature and conditions of the Work, and any risks associated with the Work. The Corporation will not be liable to the Bidder for any misunderstanding on behalf of the Bidder as to the nature and scope of the Work, or any associated risks and conditions relating to the Work.

2.26 LEGAL COUNSEL

Davis LLP has provided and continues to provide legal advice to the Corporation in respect of this RFQ. By submitting a Quotation, a Bidder is expressly consenting to Davis LLP continuing to represent and advise the Corporation in respect of this RFQ, notwithstanding that Davis LLP may have non-confidential information of the Bidder and notwithstanding any unrelated solicitor-client relationship that the Bidder may have or previously has had with Davis LLP.

2.27 BIDDER DEBRIEFING

Debriefing may be provided to unsuccessful Bidders, at the sole discretion of the Corporation.

PART 3
SCOPE OF WORK AND TIMELINES

3.1 SCOPE OF WORK

The Supplier's scope shall include all labour, material, equipment, and services to:

- Design, fabricate, assemble, test, and deliver the equipment listed in Section 1.4, complete with auxiliaries, to the job site.
- Supply drawings; bill of material; installation, operation and maintenance manuals; and any other technical documentation as required in this specification.
- Provide all material, accessories, power sources and services required to complete factory acceptance testing (FAT).
- Supply a recommended special tools list.
- Supply a recommended spare parts list.
- Provide a written guarantee that the spare parts will be available over a period of 15 years.
- Supply information upon request by the Purchaser, including any technical assistance required for installation and commissioning of the equipment.
- Provide a written warranty for the equipment and its performance.

All items, accessories, and services that are usual and/or necessary to complete the work, which may or may not have been specifically mentioned herein shall be supplied and/or provided and all in accordance with the detailed specifications (the "**Specifications**") set out in **Part 8** attached hereto (collectively, the "**Work**"). The Corporation may amend the Work at any time through this RFQ process at the Corporation's sole discretion.

3.2 ANTICIPATED TIMELINE

The Corporation expects to enter into an agreement for the Work on or before December 1, 2013, subject to receipt by the Corporation of all approvals and licenses required under any federal or territorial legislation. This condition is solely for the benefit of the Corporation, and may be waived by the Corporation in its sole discretion. The Transformers are required to be installed and in working order by no later than July 31, 2014 (the "**Completion Date**").

PART 4
SUBMISSION REQUIREMENTS

4.1 GENERAL

To provide the Corporation with complete information to enable comprehensive and accurate evaluation of the Quotations, Bidders will provide the information required by this Part 4 and the Specifications in their Quotation. Bidders should read the Specifications carefully to ensure that all submission requirements are fulfilled, as the Specifications require information to be submitted that is not set out in this RFQ. Quotations will be considered to be in full compliance with the Specifications, unless exceptions are clearly documented. Any additional information may be included at the Bidder's discretion. Omission of any information that the Corporation deems as pertinent to the Quotation may cause the Quotation to be rejected in the Corporation's sole discretion. Any supporting documentation should be attached as appendices and cross-referenced to the appropriate section of the Quotation.

4.2 PRICE

Pursuant to a transformer supply agreement, the Vendor will be paid for the Work on a progress payment schedule based on inspections performed during the course of the Work. Bidders will propose a payment schedule for the Work in Quotation Form 2.

Quotation prices will be in Canadian dollars and will include all applicable duties and taxes, and all costs of performing the Work, with the exception of the federal Goods and Services Tax (GST).

All pricing information will be submitted on Quotation Form 2 provided in Part 7 of this RFQ and will be submitted in a separate sealed envelope if the Quotation is submitted in hard copy only, or in accordance with Section 2.3 if the Quotation is submitted electronically.

Bidders will provide details regarding standard warranty provisions that will be offered for the Transformer, and the additional cost and terms for a five-year optional extended warranty.

4.3 QUALITY ASSURANCE PROGRAM

Bidders will submit a copy of their quality assurance program or manual, together with a list of international / national standards and specifications covering raw materials, components, processes, tolerances, test procedures, and a list of tests normally carried out on raw materials with a description of test equipment.

4.4 TECHNICAL SUBMISSIONS

Bidders shall refer to the Specifications for all required technical submissions.

PART 5
EVALUATION

Each Quotation will be reviewed to ensure compliance with the requirements of this RFQ. Quotations will be evaluated based on the information submitted in the Quotation.

PART 6
SUMMARY

The Corporation thanks all Bidders in advance for participating in this RFQ. We recognize the time, resources and energy that it takes to provide a Quotation. We do not take lightly the work and effort made to provide a Quotation. The Corporation is committed to the highest standards of business practice and services, and we appreciate your company helping us achieve these goals.

PART 7
LETTER OF INTENT AND QUOTATION FORMS

LETTER OF INTENT TO RESPOND

TO YUKON ENERGY CORPORATION'S REQUEST FOR QUOTATIONS #2013-036

SUPPLY OF TAKHINI SUBSTATION TRANSFORMER

RFQ #2013-036

Email to: **Matthew Sills, Buyer**
Yukon Energy Corporation
matthew.sills@yec.yk.ca

THIS IS TO CERTIFY THAT:

_____ intends to respond to the above-noted Request for Quotations.
(Name of company / individual)

Our contact is:

Name: _____

Mailing Address: _____

_____

_____

Email Address: _____

Telephone Number: _____

Facsimile Number: _____

Signed by: _____

(Print name): _____

Title: _____

Note: Only those Proponents who indicate their intent to respond will receive subsequent information.

QUOTATION FORM "1"

REQUEST FOR QUOTATION – RFQ #2013-036
SUPPLY OF TAKHINI SUBSTATION TRANSFORMER

Yukon Energy Corporation

This document must be submitted with the Bidder's Quotation in a separate envelope.

I/We hereby submit a Quotation for the Work, in accordance with these documents.

(i) I/We have carefully examined the Specifications together with all other factors affecting the Work and hereby propose to perform the Work in the manner called for in the RFQ.

(ii) If our Quotation is accepted, I/We agree to enter into a transformer supply agreement with the Corporation transformer supply agreement.

(iii) I/We acknowledge receipt of, and have taken into consideration, the following addenda issued during this RFQ:

#_____ #_____ #_____ #_____ #_____ #_____

(iv) Closing Date and Time: **November 22, 2013 at 4:00:00 PM Whitehorse Local Time**

(v) The Corporation need not necessarily accept the lowest, the highest ranked, or any Quotation, and may reject or accept any Quotation.

(vi) In consideration of being permitted to submit a Quotation, I/We agree that this Quotation is irrevocable and open to acceptance by the Corporation at any time during the Irrevocable Period, whether any other Quotation has been accepted or not.

Bidder's Full Business Name:

_____

Bidder's Full Business Address:

_____

Telephone Number: _____ **Fax**: _____

Email: _____

Attested to and delivered on behalf of the Bidder this _____ day of September 2011:

Signature(s): _____ **Title**: _____

Witness Signature: _____ **Name**: _____

QUOTATION FORM "2"

REQUEST FOR QUOTATION– RFQ #2013-036
SUPPLY OF TAKHINI SUBSTATION TRANSFORMER

Yukon Energy Corporation

This document must be submitted with the Bidder's Quotation in a separate price envelope.

Bidder's Full Business Name: _____

Address: _____

Tel.: _____

1. All prices submitted will be in **Canadian dollars,** will include all applicable duties and applicable taxes. All prices will include all costs, and no additional costs will be chargeable to the Corporation unless indicated below.

2. If a sub-total or total amount is indicated, and a price has not been entered for any payment items that forms part of the sub-total or total amount, that payment item will be deemed to have been included in the other prices that make up the sub-total or total price(s), as applicable.

3. I/We, having carefully examined the Specifications and interviewed all suppliers of materials on which this Quotation is based, confirm that I/we have the ability to complete the Work on or before the Completion Date.

4. I/We, having carefully examined the Specifications, hereby submit the following price(s) for the Corporation's consideration: (1 / 2)

   Total Contract Price (TCP) in Canadian Dollars (inc. Taxes)

   138-34.5-13.8 kV, 15/20/25 MVA step-down power transformer with a ±15% OLTC on HV side as per CSA-C88 and technical specification:

   The stipulated sum of:

   _____

   _____ **DOLLARS (**$_____)

5. The following Schedules form an integral part of this RFQ and will be submitted with Quotation Form 2:

Schedule I	Items and Unit Prices
Schedule II	List of Subcontractors
Schedule III	List of References
Schedule IV	List of Spare Parts
Schedule V	Proposed Payment Schedule
Schedule VI	Work Schedule

Name of Bidder: _____

Attested to and delivered on behalf of the Bidder this _____ day of _____ 2011.

Signature: _____

Title: _____

Witness: _____

Dated at _____ this _____ day of _____ 2011.

SCHEDULE I
ITEMS AND UNIT PRICES

The Bidder submits below the itemized breakdown which may be used to extend a transformer supply agreement requirements or to determine the cost of scope modifications during the course of a transformer supply agreement.

The total contract price for both units will reflect all costs to be borne by the Corporation. The total cost as shown below will be **inclusive** of all duties, taxes and charges, premium and allowances, or any other and miscellaneous costs required to meet the completion date.

No.	Description	Qty.	Unit Price	Total Price
1.	**Generator Step-up Transformer**			
1.1	Design, fabricate, assemble and test a 4.16-34.5 kV 9/12/15 MVA generator step-up transformer	1	$	$
1.2	Heat run test	1	$	$
1.3	Lightning impulse (BIL) test	1	$	$
1.4	Delivery to site (DDP)	1	$	$
	Federal sales tax Exempt		$	$
	Provincial sales tax Exempt		$NA	$NA
Total Contract Price (TCP) in Canadian Dollars				**$**
2.	**Optional Items**			
2.1	Transformer incipient fault monitor	1	$	$

Item	Description	Per Diem Rate
3.	Per Diem rate for services of an Installation Supervisor including room & board, and daily transportation to site	$
4.	Per Diem rate for services of a Commissioning Supervisor including room & board, and daily transportation to site.	$

It shall be understood that:

a) Per Diem rates tendered above are for a working day of_____ hours, and that any overtime will be paid as per the following hourly rates:

- Installation Supervisor: $ _____ per hour
- Commissioning Supervisor: $ _____ per hour

b) Work carried out on statutory holidays, Saturdays and Sundays, will be paid as per the following rates:

- Installation Supervisor: $ _____ per hour
- Commissioning Supervisor: $ _____ per hour

c) A round-trip to the site if required, by air (economy class), shall be billed at cost to the Purchaser.

SCHEDULE II
LIST OF SUBCONTRACTORS

Where the Bidder proposes to use major components or services provided by sub-contract, these sub-contractors will be designated in the tabulation following.

If the Bidder later determines a requirement to change the designated subcontractors, it will be noted that such changes may only be made with the written agreement of the Corporation.

Where no subcontractor is named for particular components or services, it will be assumed that the Bidder will supply such components and services from internal sources.

EQUIPMENT OR SERVICES	**DESIGNATED SUBCONTRACTOR**

SCHEDULE III
LIST OF REFERENCES

In support of this Quotation;

Bidders will identify manufactured units which approximate the requirements specified by the Corporation.

Bidders will provide outline drawing with dimensions and oil quantity of manufactured units which approximate the requirements specified by the Corporation.

Where these precedents are available in the Bidder's standard format, a separate submission will be acceptable.

Transformer references will advise voltage and MVA ratings, number of units, customer and year of manufacture.

SCHEDULE IV
LIST OF SPARE PARTS

The Bidder will submit itemized unit prices for recommended components or material which will be considered for purchase by the Corporation, as per the Spare Parts List and Special Tools List found in the Specification in Part 8.

SCHEDULE V
PROPOSED PAYMENT SCHEDULE

The Bidder will propose a payment schedule for the Work based on progress milestones, including any deposit required.

SCHEDULE VI
PROPOSED WORK SCHEDULE

1. WORK SCHEDULE

For each key activity listed below, Column A shows the required target date, and the Tenderer shall provide in Column B, the dates which, if approved by the Corporation upon Contract award, shall make up the contractual Work Schedule.

Table 1: Work Schedule

Key Activities	Column A Dates Specified by the Corporation	Column B Dates Proposed by Tenderer
1. Notice of Award		
2. Remittance of documents and/or drawings:		
a) Program of Execution	+2 weeks*	
b) Design Review	+4 weeks*	
c) Drawings and Documents:		
▪ For review	+4 weeks*	
▪ Certified for fabrication	+6 weeks	
3. Execution of the work:		
a) Start Fabrication		
b) End of Fabrication		
c) FAT	June 1 , 2014	
4. Site Delivery DDP	July 22, 2014	
5. Final receipt of all documents specified in Contract	July 31, 2014	

*After P.O. award _____

PART 8
SPECIFICATIONS

The following documents make up the Technical Specifications:

S151-T1 Transformer -01 Technical Specifications Rev.2

S151-T1 Transformer -02 Data Sheet Rev.0

S151-T1 Transformer -03 Tools and Parts Rev.0

YUKON ENERGY

S151-T1 TRANSFORMER

TECHNICAL SPECIFICATION

Prepared by: Michael Tilbrook
Reviewed by: Not reviewed

File Number: 1826-08-02

REVISION LOG

Revision	Date	Amendment
00	2013/10/07	Draft for review
01	2013/10/11	Review comments incorporated
02	2013/10/16	Amendments to fall arrest system requirements

TABLE OF CONTENTS

1. Overview 3
1.1. Background 3
1.2. Scope of Works 3
1.3. Work Excluded 3
1.4. Material Supply 4
2. General requirements 5
2.1. Codes and Standards 5
2.2. Quality Assurance 6
2.3. Submittals and Transmittals 6
3. Technical Requirements 8
3.1. Service Conditions 8
3.2. Performance Requirements 9
3.3. Construction 11
3.4. Testing and test reports 21
3.5. Shipping 22
4. Documentation 23
4.1. Tender Submittals 23
4.2. Construction Submittals 23

1. OVERVIEW

1.1. BACKGROUND

Yukon Energy is installing a new natural gas generating plant near its existing Whitehorse facilities. The generating plant will operate at a nominal 4.16 kV, and connect into the Yukon Energy grid via a 34.5 kV distribution line.

To make the connection between the generating plant and the distribution line, a new substation will be installed adjacent to the generating plant. The substation is designated S151, and will include a generator step-up transformer to interface between the generating plant and the distribution system.

This specification describes the quality, material, and workmanship requirements for the design, fabrication, assembly, testing, and delivery of the generator step-up transformer.

1.2. SCOPE OF WORKS

The Supplier's scope shall include all labour, material, equipment, and services to:

- Design, fabricate, assemble, test, and deliver the equipment listed in Section 1.4, complete with auxiliaries, to the job site.
- Supply drawings; bill of material; installation, operation and maintenance manuals; and any other technical documentation as required in this specification.
- Provide all material, accessories, power sources and services required to complete factory acceptance testing (FAT).
- Supply a recommended special tools list.
- Supply a recommended spare parts list.
- Provide a written guarantee that the spare parts will be available over a period of 15 years.
- Supply information upon request by the Purchaser, including any technical assistance required for installation and commissioning of the equipment.
- Provide a written warranty for the equipment and its performance.

All items, accessories, and services that are usual and/or necessary to complete the work, which may or may not have been specifically mentioned herein shall be supplied and/or provided.

1.3. WORK EXCLUDED

The following work shall be specifically excluded from the Supplier's scope:

- Equipment foundations
- Anchor bolts
- Pipe work, electrical cables and conduits external to the equipment
- Transformer unloading (will be done by the Contractor)

1.4. MATERIAL SUPPLY

Equipment Designation	Quantity	Description
S151-T1	1	4.16-34.5 kV, 9/12/15 MVA generator step-up transformer.

2. GENERAL REQUIREMENTS

2.1. CODES AND STANDARDS

2.1.1. General

The electrical characteristics and mechanical features of the equipment supplied under this specification shall be capable of meeting all the requirements specified herein and shall conform to the latest revisions of applicable ANSI, CSA, IEEE, NEMA and EEMAC Standards including, but not limited to, the following:

Standard	Description
CSA/CAN3-C13	Instrument Transformer
CSA C22.1	Canadian Electrical Code – Part 1: Safety Standard for Electrical Installations
CSA C22.2	Canadian Electrical Code – Part 2: Safety Standards for Electrical Equipment
CAN/CSA-C50	Mineral Insulating Oil, Electrical, for Transformer and Switches
CAN/CSA-C88	Power Transformers and Reactors
CAN/CSA-C88.1	Power Transformer and Reactor Bushings
CAN/CSA-C60044-1	Instrument Transformers – Part 1: Current Transformers
CAN/CSA-C60044-3	Instrument Transformers – Part 3: Combined Transformers
CAN/CSA-C60044-6	Instrument Transformers – Part 6: Requirements for Protective Current Transformers for Transient Performance
IEEE C57.12.00	General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers
IEEE C57.12.10	Requirements for Liquid-Immersed Power Transformers
IEEE C57.12.70	Terminal Markings and Connections for Distribution and Power Transformers
IEEE C57.12.80	Terminology for Power and Distribution Transformers
IEEE C57.12.90	Test Code for Liquid-Immersed Distribution, Power, and Regulating Transformers
IEEE C57.13	Requirements for Instrument Transformers
IEEE C57.19.00	General Requirements and Test Procedure for Power Apparatus Bushings
IEEE C57.19.01	Performance Characteristics and Dimensions for Outdoor Apparatus Bushings
IEEE C57.91	Guide for Loading Mineral-Oil-Immersed Transformers and Step-Voltage Regulators
IEEE C57.98	General Requirements and Test Procedure for Power Apparatus Bushings
IEEE C57.106	Guide for Acceptance and Maintenance of Insulating Oil in Equipment
IEEE C57.113	Recommended Practice for Partial Discharge Measurement in

	Liquid-Filled Power Transformers and Shunt Reactors
IEEE C62.11	Metal-Oxide Surge Arresters for AC Power Circuits (>1 kV)
NBC	National Building Code of Canada
ANSI/NETA ATS	Acceptance Testing Specifications for Electrical Power Equipment and Systems

In addition to the above standards, the following local codes and regulations shall apply when applicable:

- Electrical Protection Act (Yukon Territory)
- Occupational Health and Safety Act (Yukon Territory)
- Workplace Hazardous Material Information System Regulations (WHMIS)

Compliance of the equipment and all its associated parts with the above-mentioned standards does not relieve the Supplier from the responsibility of supplying the equipment and accessories of proper design, electrically and mechanically suited to meet the guaranteed values at the specified service conditions.

2.1.2. **Conflicting Documents**

If any of the requirements in this specification are in conflict with the standards, the Supplier shall notify the Purchaser upon discovery. The equipment that does not comply with the Technical Specification shall be rejected and credited, replaced, or brought into full compliance at the Supplier's expense.

Where there exists a conflict between any requirements of the standards mentioned above, their references, or the Technical Specification, the Supplier shall apply all the requirements or the most stringent requirements of the conflicting documents so that the design, manufacture and testing of the equipment are carried out to the highest degree of quality set by the documents.

In case of conflict between standards, CSA shall take precedence over ANSI/IEEE unless otherwise specified.

2.2. QUALITY ASSURANCE

2.2.1. **General**

The Supplier shall establish and maintain an inspection program for quality assurance conforming to the latest version of CSA CAN3-Z299.3 and ISO standards.

2.3. SUBMITTALS AND TRANSMITTALS

2.3.1. **General**

The Purchaser operates an intranet system based on Microsoft Sharepoint. The Purchaser will set up a Sharepoint site for the Supplier, and provide log-in details to staff of the Supplier as reasonably required.

In using the project Sharepoint site, the Supplier shall comply with all IT requirements set by the Purchaser.

2.3.2. **Submittals**

Electronic submittals from the Supplier should be made by uploading the documents to the project Sharepoint site, and then notifying the Purchaser by e-mail. Submission by other methods shall only be acceptable if the project Sharepoint site is unavailable.

Non-electronic submittals shall be delivered by person or by registered mail to:

Yukon Energy Corporation
2 Miles Canyon Rd
Box 5920
Whitehorse, YT Y1A 6S7

All submittals shall be addressed to the Purchasers' designated contract manager, and shall include a cover sheet with the Purchaser's purchase order and contract numbers, the project title, and a complete listing of the submittal contents.

2.3.3. **Transmittals**

The Purchaser will provide electronic transmittals to the Supplier via the project Sharepoint site by preference. Transmission my other methods may be used if the project Sharepoint site is unavailable.

Non-electronic transmittals may be delivered by mail to the address nominated by the Supplier.

3. TECHNICAL REQUIREMENTS

3.1. SERVICE CONDITIONS

3.1.1. General

The transformer will be installed outdoors in Whitehorse, on a concrete base inside the substation for a new natural gas generating plant to be located near Yukon Energy's existing Whitehorse facility.

In normal operation, the transformer will be used to supply power from the natural gas generating plant to the Yukon Energy grid, however when the generators are shutdown, the transformer may also be used to supply auxiliary station service power from the Yukon Energy grid to the natural gas generating plant.

3.1.2. Environmental Data

Installation		Outdoors
Ambient temperature range	°C	-50 to +40
Relative humidity	%	18-95% average
Elevation above sea level	m	< 1000
Iskeraunic level	days per year	4-8
Wind:		
Continuous	km/h	108
Gust	km/h	140
Ice buildup	mm	15
Snow accumulation	mm	1,300
Peak Ground Acceleration (seismic)	g/zone	0.25G
Geomagnetic Storm		Moderate

3.1.3. Primary Electrical System Data

		HV	LV
Nominal system voltage	kV rms	34.5	4.16
Normal steady-state operating limits	kV rms	32.8-36.2	3.7-4.6
Maximum temporary (10 minutes) system voltage	kV rms	41.4	6.24
Maximum short-term line-to-ground system voltage:			
30 seconds	kV rms	25.5	
5 seconds	kV rms	30	
1 second	kV rms	31.5	
Number of phases/wires		3/4	3/3
Rated frequency	Hz	60	
System grounding:			
High-voltage system (34.5 kV)		Solidly grounded	
Low-voltage system (4.16 kV)		Resistance grounded	

		(ungrounded when generators offline)

Rated short circuit level (34.5 kV system):

Three-phase fault	kA (sym)	500 MVA
X/R ratio		< 10
Line-to-ground fault	kA (sym)	500 MVA
X_0/R_0 ratio		< 3

3.1.4. **Auxiliary Electrical Systems Data**

The following auxiliary supplies are available:

- 208/120 Vac three-phase/four-wire grounded system, 60 Hz, for cooling fans, lighting, heating and convenience outlets.
- 125 Vdc ungrounded system for protection and control systems.

3.2. PERFORMANCE REQUIREMENTS

3.2.1. **General**

The transformer shall meet the following requirements:

Rated power:		
Nominal (ONAN)	MVA	9
First stage fans (ONAF1)	MVA	12
Second stage fans (ONAF2)	MVA	15
Rated nominal voltage:		
Primary winding (LV)	kV rms	4.16
Secondary winding (HV)	kV rms	34.5
Rated frequency	Hz	60
Positive sequence impedance (at nominal tap)	Per unit	0.070
Admissible average temperature rise of any winding above ambient temperature measured by resistance	°C	55
Admissible temperature rise for the insulation system (thermally upgraded paper)	°C	65
Vector grouping		dYN11
Rated impulse withstand voltage (full wave):		
<u>Windings</u>		
Primary (LV) winding	kV peak	75
Secondary (HV) winding	kV peak	200
<u>Bushings</u>		
Primary (LV) bushings	kV peak	75
Secondary (HV) bushings	kV peak	200
Secondary (HV) neutral bushings	kV peak	200
Rated power frequency withstand voltage (applied		

voltage at 60 Hz for one minute):

Windings		
Primary winding	kV rms	19
Secondary winding	kV rms	70
Bushings		
Primary bushings	kV rms	27
Secondary bushings	kV rms	70
Secondary neutral bushings	kV rms	70
Bushing minimum creepage distance:		
Primary bushings	mm	150
Secondary bushings	mm	950
Secondary neutral bushings	mm	950

Surge arresters:

		HV	LV
Arrester voltage rating (duty cycle voltage)	kV rms	30	6
Arrester maximum continuous operating voltage (MCOV)	kV rms	24	5.1

Admissible audible noise:		
Without fans in service	dBA	72
With all first stage cooling fans in service	dBA	73
With all second stage cooling fans in service	dBA	74

3.2.2. **Short-circuit Rating**

The transformer windings and other parts shall withstand, without damage or permanent deformation, the effects of a three phase and line-to-ground short circuit at the transformer terminals of two (2) second duration. The short-circuit currents shall be calculated using the minimum anticipated transformer impedance (including the effect of tap changing equipment) and the ultimate system short circuit level at the maximum steady state voltage (as listed in Section 3.1.3) as the pre-fault voltage.

3.2.3. **Admissible Overload Capacity:**

The transformer shall be designed for overloading in accordance the latest edition of the IEEE standards and of CAN/CSA-C88.

The transformer must be designed to safely operate without any loss of life continuously through the entire ambient temperature range (as listed in Section 3.1.2) with the following CAN/CSA-C88 overloading capacity down to the minimum ambient temperature:

- ONAN rating increase of 1.0% for each degree Celsius below 25°C ambient.
- ONAF rating increase of 0.75% for each degree Celsius below 25°C ambient.

The 0°C ambient admissible rating must be indicated on the transformer nameplate.

3.2.4. **Energization at Low Temperature**

The transformer shall be designed such that it can be energized successfully at the minimum design ambient temperature (as listed in Section 3.1.2) from a prolonged de-energized state.

The vendor shall advise if the transformer is recommended to be energized continuously especially under low temperature conditions.

3.2.5. **Evaluation of Tenders for Losses**

In order that the transformer results in the most economical operation of the system, the tenders will be evaluated taking into consideration the capital cost and the operating cost (losses evaluated at nominal ONAN fundamental rating).

The transformer losses will be evaluated as follows (in Canadian Dollars):

- $15,000 per kW for no-load losses
- $10,000 per kW for load losses

The following formula will be used to establish comparative tender prices:

Ca = C + 15,000 PV + 10,000 PC

Where:

Ca	=	Comparative tender price in Canadian Dollars
C	=	Tender price in Canadian Dollars
PV	=	No-load losses in kW (guaranteed) at nominal ratings
PC	=	Load losses in kW (guaranteed) at rated fundamental current

If the losses as tested exceed the losses as guaranteed, the Purchaser may choose to accept the transformer with a penalty being paid by the Supplier to the Purchaser. The penalty shall be calculated by subtracting the present worth of the losses as guaranteed from the present worth cost of the losses as tested, using the same loss-evaluation figures as in the tender evaluation. This penalty is applicable without tolerance if either the no-load losses or the load losses as tested exceed the no-load losses or the load losses as guaranteed.

3.3. CONSTRUCTION

3.3.1. **Tank and Base**

General

The transformer shall be enclosed in a suitably stiffened welded steel tank suitable for outdoor service and designed so that the transformer can be safely transported. When fully oil-filled, the transformer shall be able to be jacked, lifted, and hauled into place without permanent deformation or leakage.

The design of the tank, cover and all accessories and fittings shall not have any external pockets or dips in which water can lodge or pond, or internal pockets in which oil can remain when draining the tank or in which air can be trapped.

The transformer, including all accessories and fittings, shall be designed to withstand, without deformation, full vacuum and positive and negative pressures in accordance with CAN/CSA-C88.

The tank shall be treated to remove all dust, grease and chemicals and the inside shall be painted with a high gloss white paint that is not affected by, or in itself does not affect, the transformer oil.

All vertical and horizontal box stiffeners on the tank walls shall be provided with drain holes on the underside.

The centers of gravity shall be marked on each side of the tank for both during transport and at site, fully assembled.

Base

The base of the tank shall be designed so it is possible to move the tank in any direction, without damage, by using rollers, plates, rails, or air flotation pads, or by skidding.

The bottom plate of the transformer tank shall be designed 3 mm thicker than required by standard design strength requirements to tolerate possible rusting.

Cover

A sloped, welded cover shall be provided for the main tank. The cover shall be provided with lifting lugs.

Metallic bases (supports) shall be welded to the top cover for use with the fall arrest system. The quantity and placement shall be optimised in order to minimise the number of fall arrest systems required for safe access to all areas of the top cover.

Access Openings

Openings shall be provided in the tank to give access to the internal connections of all bushings (for installation and removal), grounding connections, current transformers and tap changing mechanisms, without removing the top cover or the radiators.

The transformer tank cover shall be provided with a sufficient number of 600 mm minimum diameter manholes to allow inspection access to the core and coils.

Access Ladder and Fall Arrest/Restraint System

A yellow painted ladder shall be provided with suitable protected access and provision for padlocking. The side rails shall extend three (3) feet above top of tank to allow safe access and exit.

The Supplier shall provide a fall arrest/restraint system to allow safe access to all areas of the top cover and to components mounted on the top cover. The fall arrest/restraint system shall meet the following requirements:

- The fall arrest/restraint system shall consist of removable anchor posts that attach to metal bases welded to the top cover of the transformer.
- If a ready-made anchor post system is used, DBI-Sala and Miller are the preferred manufacturers. The use of any other manufacturer shall be subject to approval by the Purchaser.
- The Supplier shall optimise the location of top-mounted components so that the number of separate anchor posts required to allow safe access to all areas of the top cover is minimised.
- The fall arrest/restraint system shall meet all applicable standards, legislation, certifications and other requirements necessary for use as a fall arrest system in the Yukon Territory, Canada.
- The Supplier shall provide a design calculation note and detail drawings for the proposed system. The ultimate load capacity and design maximum arrest force of the fall arrest/restraint system shall be clearly identified.

Lifting, Jacking and Haulage

The transformer shall be designed to allow for transportation, including lifting, jacking and haulage.

Jack steps shall be provided at each corner at a height of no less than 300 mm and no more than 380 mm.

Pulling eyes shall be provided on the base at each corner.

Lifting lugs or hooks shall be provided near the top of the tank at each corner suitable for fitting shackles or lifting cables.

Grounding Pads

Two stainless steel ground pads shall be provided and installed diagonally opposite at the bottom of the tank with compression type lugs for #4/0 to 500 MCM bare copper conductors.

Gaskets

Sealing gaskets of superior quality shall be provided to avoid all risks of oil leakage. Such gaskets shall withstand the following conditions without damage:

- Maximum operating temperature during overload conditions and maximum design ambient temperature.
- The minimum ambient temperature while the transformer is deenergised and without any external heat source.

It is very important that the Supplier take extreme precautions to ensure proper sealing of the transformer tank, cooling system and accessories to avoid any chronic problem(s) related to oil leakage. Gaskets shall be fully compatible with the type of oil supplied and a certificate of compatibility shall be provided. Furthermore, gaskets shall not cause any adverse foaming effect during oil treatment process.

One set of spare gaskets shall be provided for the manhole and handhole covers and for all bushings and openings, during site installation.

3.3.2. **Liquid Preservation System**

Conservator Tank

The preferred liquid preservation system shall consist of a detachable conservator tank with sufficient capacity to accommodate the change in oil volume for the maximum variation of temperature to which the transformer will be exposed throughout its load range including overload operation. The conservator shall include a bladder to isolate oil from outside air.

The conservator tank shall be designed to withstand, without deformation, full vacuum and positive and negative pressures in accordance with CAN/CSA-C88.

The conservator shall be designed to permit complete draining via a drain valve. Accordingly, the conservator shall be sloped, and any reinforcing members shall be arranged to allow the free passage of oil along the bottom of the conservator.

Sealed Tank

A sealed tank design will also be considered if, and only if, the active part inside the tank will never be exposed to air at the minimum design ambient temperature (as listed in Section 3.1.2).

If used, a sealed tank design shall consist of a nitrogen-blanket system. The system shall include the following features:

- A pressure relief valve and a make-up gas system such as ABB Inertaire gas preservation system to ensure that the nitrogen pressure is maintained within safe limits.
- Dial-type pressure indicators showing the gas pressure in the transformer tank and in the make-up nitrogen tank.

- Valves as required to allow the make-up nitrogen tank to be replaced without removing the transformer from service, and to facilitate testing of the system.
- Change-over contacts indicating low gas, low pressure and high pressure shall be provided.

3.3.3. **Core**

The transformer core shall be made from high-grade grain-oriented non-aging sheet steel laminations.

The core shall be grounded at one point only with a core ground strap of sufficient cross-sectional area and conductivity to withstand the worst possible short-circuit current for one (1) second. The Supplier shall state the withstand capability of the ground strap.

The core ground shall be brought through the tank, using a core bushing (2.5 kV class) to allow core insulation test to be performed with a 5 kV DC hi-pot from outside of the tank. Suitable mechanical protection for the core bushing shall be provided.

3.3.4. **Windings**

The core and coil assemblies shall be of heavy-duty class, round core and circular coil design. Where applicable, the windings shall be of disk and/or helical disk heavy duty construction.

The windings shall be manufactured from copper.

The winding insulation shall be of thermally-upgraded cellulose. Each winding shall be fully insulated; graded insulation shall not be acceptable.

All joints shall be welded or brazed without hydrogen embrittlement. Compression type connectors may be used for terminal connections or to attach leads to winding conductors. Bolted connections shall use suitable locking devices.

3.3.5. **Bushings, Connectors, and Terminals**

General

The current carrying parts and bushings shall have the capacity to withstand, as a minimum, the highest rating of the transformer including overloading.

Primary (LV) Winding Connections

A self-supporting, air-filled terminal box shall be provided for the primary (LV) connections. The terminal box shall be provided with bushings suitable for the connection of up to four cables per phase (cable type: 750 MCM TECK, 15 kV class, 100% insulation, copper conductor, XLPE insulation). Bushings shall be provided with the maximum creepage distance for their voltage class.

The terminal box shall be designed for bottom-entry of the incoming power cables, and shall include a removable, undrilled non-magnetic bottom plate. A hinged front cover complete with provision for padlocking shall be provided.

A 50mm x 3mm tin-plated copper bus bar shall be provided in the terminal box for grounding. The bar should cover the entire width of the terminal box.

Secondary (HV) Winding Connections

Secondary line and neutral bushings shall be top cover mounted, oil filled condenser type, complete with liquid level indication, and equipped with terminal connectors suitable for up to one (1) 1796 MCM AAL conductor per phase. Bushings shall be provided with the maximum creepage distance for their voltage class.

The secondary bushings shall be suitable for power factor testing. Draw leads of sufficient length shall be provided on HV bushings to allow them to be pulled out of bushing caps for separate power factor testing of the transformer windings and bushings.

The secondary neutral bushing shall be brought to the ground with a copper bus bar mounted on insulators. The copper bus bar should go from the bushing to the bottom of the tank.

3.3.6. Current Transformers

General

Current transformers shall be mounted on each transformer bushing as specified below.

Secondary wiring within the transformer tank shall not be less than #8 AWG copper. All taps shall be brought out to a suitable terminal compartment accessible from ground level. All secondary wiring shall be passed through the tank wall via bolted through-type bushings.

Location and Type

The following current transformers shall be provided:

	Primary (LV) line bushings	**Secondary (HV) line bushings**	**Secondary (HV) neutral bushing**
Quantity	Two per phase	Two per phase	Two per phase
Ratio	2000-5A MR	600-5A MR	600-5A MR
Accuracy class	C200 and 0.3B1.8	C200 and 0.3B1.8	C200 and 0.3B1.8
Service factor (SF)	1.5	1.5	1.5

3.3.7. Cooling System

General

The Supplier shall design and guarantee the performance of its cooling system.

Radiators

The Supplier shall provide crevice free radiators designed and manufactured to withstand the same pressure/vacuum conditions as the main tank (preferred type: Menk, galvanized steel).

The Supplier shall equip the radiators with a drain valve and plug at the bottom and a vent plug at the top. The Supplier shall attach the radiators to the main tank via positive sealing isolating flanged valves, with position indicators, affixed to the main tank.

Cooling Fans

The Supplier shall provide two stages of cooling fans to allow the required transformer ratings to be met within the permissible temperature rises.

The fan assemblies shall be rigidly fixed to avoid excessive vibration. The fans shall not be located under the coolers or where they may be blocked by snow or debris. The fans shall have a visible nameplate.

Fan motors shall be totally enclosed, class F, and shall be rated 3-phase 208 V, 60 Hz with a load factor of 100% and a service factor of 1.15 (preferred type: Krenz). Fan motor starters provided shall be readily available in North America.

The Supplier shall provide separate control “Hand-Off-Auto” for each stage of fans. Provision for remote indication of each fan step shall be provided.

3.3.8. **Insulating Liquid**

The insulating liquid shall be suitable for -50°C temperature and shall meet the most stringent requirement of the ASTM D1275 standard regarding the admissible corrosive sulphur/copper sulphide deposition. The preferred types of oil are VoltEsso 35 and Luminol.

The transformer shall be supplied complete with the first filling of transformer oil. The transformer shall be filled under vacuum.

All topping-up oil for the transformer, the conservator and the radiators shall also be provided by the Supplier.

Stickers affixed on the transformer tank and the tap-changer tank shall be provided, certifying that the oil is free from PCB's down to a level of 2.0 PPM or less.

3.3.9. **Control Cabinet**

General

A control cabinet shall be provided to house:

- Auxiliary equipment associated with the cooling control system, including disconnect switches complete with HRC fuses for the incoming power supply, fan starters, control switches required for the various modes of operation, and all other accessories.
- Current transformer connections
- Alarm and trip connections
- Other control devices and connections as needed

The cabinet shall consist of two separate sections for 120/208V power components, each section having a separate full-size, padlockable, hinged door. The first section of the cabinet shall house the 120/208 V components only (starters, etc.), while the second section shall house the 120 V components only (terminal blocks, alarms, contacts, CTs secondary circuit and others accessories). Ample space to accommodate all equipment shall be provided.

The control cabinet shall be weatherproof and thermally insulated for the intended environmental conditions as listed in Section 3.1.2. The cabinet shall be NEMA-4X rated for weather protection. The cabinet shall be insulated with Ottawa Fiber, OF1-40FSK board from the inside, with all metallic foils shall be bonded to earth.

The inside of the cabinet shall be painted with an oil-proof white paint having anti-condensation properties.

The control cabinet shall be equipped with a light fixture, a light switch, an inside GFCI duplex receptacle (Hubbel, NEMA 5-15 R, cat. no GF5262IA with wall plate HPS1I) and a thermostatically controlled anti-condensation heater, all operated from a 120 Vac supply.

The control cabinet, the wiring and all accessories shall be CSA approved and the CSA label shall be affixed to the control cabinet.

The cabinet shall be fixed to the transformer tank wall. The cabinet shall be rigidly braced, constructed, and located so as not to add to or amplify the sound level of the transformer. The mounting height shall be suitable for the operation of switches and the reading of indicating instruments from a ground level position. The transformer tank wall below the cubicle shall be free of all obstructions to allow installation of power and control cables.

Cables and Wiring

All wiring shall be stranded copper, #14 AWG minimum size (#10 AWG minimum size for CT leads), and shall conform to CSA. Door-mounted instruments shall be wired with highly flexible conductors.

All wiring shall be identified with wire markers or an equivalent acceptable by the Purchaser according to the information given on the wiring diagrams.

All wires on devices shall be terminated with compression type insulated connectors. Spade lugs or soldered terminals are not acceptable. No more than two wires shall be connected to any one stud or terminal.

All wiring shall be protected and supported within the control cabinet to protect it from damage.

All cabling and wiring to devices on the transformer and radiators shall be provided with non-ferrous, non-corroding armor or conduit for mechanical protection, and shall be securely attached to the tank. All wiring shall be connected prior to shipment. The Purchaser will reconnect wiring in instances where shipping constraints require disconnection.

Dedicated terminal blocks and wire ways shall be provided within the control cabinet for all external (Purchaser) connections.

Cables entry shall be at the bottom of the control cubicle.

A removable undrilled gland plate shall be provided at the bottom of the enclosure for entrance of Purchaser cables or conduits.

Terminal blocks for Purchaser use shall be rated 750 V, of the compression type, suitable for connection of wire sizes up to 6 mm^2. Terminal blocks for CT connections shall be suitable for use with ring terminals and wire sizes up to 10 mm^2.

Twenty percent (20%) extra terminals shall be provided for future use.

Switching Devices

Each group of fans (stages) shall have its own motor starter complete with indidual protection.

Each safety switch, breaker and motor starter shall be individually padlockable in open position. All breakers shall be equipped one normally-closed auxiliary contact (contact shall close when the circuit breaker is open/tripped).

All safety switches, breakers, starters and relays shall be readily available in North America.

Auxiliary Supplies

A single 120/208Vac, three-phase four-wire, 60 Hz auxiliary supply shall be provided to the cabinet by the Purchaser.

Auxiliary loads within the cabinet (GFCI receptacle, light fixtures, cabinet heaters) shall use 120 Vac single-phase.

3.3.10. **External Attachments and Valves**

The supplier shall provide the following valves and attachments:

- A 2 inch IPS minimum connecting pipe with an indicating gate valve shall be provided between the conservator and main tank.
- A 2 inch valve shall be provided on the tank cover for vacuum hose attachment.

- Diagonally opposite to the valve described immediately above, a 4 inch valve shall be provided on the tank cover for filter press connection. A spray nozzle shall be provided inside the tank for this valve.
- Diametrically opposite to the valve described above, provide a 4 inch drain valve at the bottom of the tank, which permits removal of all residual oil from the tank. Provide this valve with a non-corroding plug.
- Incorporated within the valve described above, provide a 1/2 inch globe valve with non-corroding plug for oil sampling. Sampling valve shall be easily accessible and located approximately 4 inches from the bottom of the tank.
- Provide a permanent fitting and valves to allow connection of the GE Kelman-Tranfix monitor as detailed under Accessories below. These fittings shall be provided regardless of whether the monitor is installed.

All nuts and bolts, 1/2 inch and smaller, and screws exposed to weather shall be made with non-magnetic and non-corroding material.

3.3.11. **Paint Finish**

The Supplier shall take all necessary measures to avoid premature corrosion of the transformer. The following minimum requirements shall be met:

- An epoxy coating finish shall be applied to the transformer, with paint thickness no less than 3 mils. The paint process shall be submitted to the Purchaser for review.
- The top cover of main tank, OLTC cabinet, and all other cabinets of sufficient dimension to allow a person to stand on shall have an anti-slip coating applied over the final paint coating.
- The colour shall be standard ANSI 70-grey.
- Two pressurized spray cans (approx. one pint each) and one pint of finish paint for touch-up on site shall be provided.

If additional measures are required or recommended to provide adequate protection, the Supplier shall include full details of the paint specification with the tender.

The Supplier may propose a better paint process as an option with the tender.

3.3.12. **Accessories**

In addition to the accessories specified in CAN/CSA-C88, the Supplier shall provide the following:

- Gas detector relay: ETI Buchholz relay series RR with the following features:
  - Two change-over contacts for gas accumulation, for use by the Purchaser.
  - Two change over contacts for oil flow/low oil level, for use by the Purchaser.
  - Gas receiver ETI type RAGA B, mounted at an easily accessible level, to allow for gas sampling and testing of the Buchholz relay.

  If a sealed tank liquid preservation system is used, the Supplier shall propose an equivalent sudden pressure relay suitable for detecting internal transformer faults with sealed tank operation. The relay type shall be subject to approval by the Purchaser.
- Oil level indicator: Messko MTO-series oil level indicator with the following features:

- Dial-type indication of transformer oil level referenced to temperature.
- Three change-over contacts configured for high alarm, low alarm and low trip levels, each of which shall be available for use by the Purchaser. All contacts shall be wired back to the control cabinet.
- A 4-20 mA signal for remote indication of transformer oil level.

– Winding temperature indicator (WTI): Messko or AKM temperature indicator with the following features:

- Dial-type indication of the transformer winding hottest spot temperature, including a manually resettable drag hand indicating the maximum temperature reached.
- A minimum of four change-over contacts, each of which operates at an individually adjustable pre-set temperature. At least two of the contacts must be made available for use by the Purchaser. All contacts shall be wired back to the control cabinet.
- A 4-20 mA signal for remote indication of winding temperature. The signal shall be wired back to the control cabinet.

– Top oil temperature indicator (OTI): Messko or AKM temperature indicator with the following features:

- Dial-type indication of transformer top oil temperature, including a manually resettable drag hand indicating the maximum temperature reached.
- A minimum of two change-over contacts, each of which operates at an individually adjustable pre-set temperature. At least two of the contacts must be made available for use by the Purchaser. All contacts shall be wired back to the control cabinet.
- A 4-20 mA signal for remote indication of top oil temperature. The signal shall be wired back to the control cabinet.

– Pressure-relief device (PRD): Messko pressure relief device with the following features:

- Self-reclosing operation.
- Manually-resettable semaphore indicating operation of the device.
- Two manually-resettable change-over contacts indicating operation of the device for use by the Purchaser.
- Directional shroud and piping to direct oil spray safely to the oil containment basin.

The Supplier shall provide a detailed study justifying the selection of the pressure-relief device, including quantity, location and rating, so as to avoid the risk of having tank rupture under internal fault.

All instruments and indicators shall be suitable to operate down to -50°C.

All alarm and trip contacts shall be heavy duty rated, 10 A, 125 Vdc. Interposing relays are not acceptable for achieving the required quantity and rating of contacts.

All contacts and 4-20 mA signals shall be wired back to the control cabinet.

All indicators and semaphors shall be readily visible from ground level. The top oil and winding temperature indicators shall be mounted at human height to allow for resetting of the drag hands.

The Supplier shall also provide an optional cost for the addition of an Intelligent Transformer Incipient Fault Monitor, type Kelman Transfix, & gaz by GE, complete with transmitter, auxiliary contacts, controller, software, accessories and output signal wired to the control cabinet.

3.3.13. **De-energised Tap Changer (DETC)**

The transformer shall be equipped with a de-energised tap changer (DETC) on the high-voltage winding with the following features:

- The following tap steps are required: ±2 x 2.5% from the transformer nominal voltage.
- The tap changer shall be suitable for de-energised operation. On-load tap changing is not required.
- The tap changer shall be rated for the maximum rating of the transformer, including overloading.
- Provisions for locking the tap changer in position using a Purchaser-supplied padlock in each position shall be included.

3.3.14. **Surge Arrestors**

The Supplier shall provide surge arrestors as follows:

- High-voltage terminal arrestors: A set of three single-phase Siemens arrestors with the following features:
  - The surge arrestors shall be gapless metal-oxide type with a porcelain housing.
  - Station-class arrestors with a minimum fault rating of 10 kA shall be used.
  - Each arrestor shall be mounted on the top cover of the transformer in the vicinity of the associated bushing. An insulating sub-base and mounting bolts shall be provided as required for the discharge counter and leakage current indicator.
  - Each arrestor shall be fitted with a pressure-relief device for each section.
  - Each arrestor shall have the maximum creepage distance for its class.
  - Line terminal connectors suitable for bare aluminum conductors up to 1796 MCM shall be provided.
  - Ground terminal connectors suitable for 4/0 bare copper conductor shall be provided.
  - Each arrestor shall be provided with a hermetically-sealed discharge counter and leakage current indicator. Compression type lugs suitable for 4/0 bare copper conductor shall be provided with each discharge counter.
- Low-voltage terminal arrestors: A set of three single-phase Siemens arrestors with the following features:
  - The surge arrestors shall be gapless metal-oxide type with a polymer housing.
  - Station-class arrestors with a minimum fault rating of 10 kA shall be used.
  - Each arrestor shall be mounted in the low-voltage terminal box in the vicinity of the associated bushing. Each arrestor shall be connected to the appropriate terminal bushing and ground using minimum 4/0 copper conductor. Adequate allowance for entry of the low-voltage cables shall be provided.

3.3.15. **Nameplates**

The Supplier shall provide a transformer nameplate in compliance with the CAN/CSA-C88 standard. The nameplate shall indicate that the transformer was designed, built and tested in accordance with the CAN/CSA-C88 standard.

The Supplier shall also provide nameplates for all ancillary equipment and all drainage, filling and sampling valves.

Nameplates on bushings shall indicate the type, designation and catalogue number. A nameplate on the cover beside each bushing shall indicate the bushing terminal marking.

Nameplates on drainage, filling and sampling valves shall indicate their purpose.

Nameplate shall be made of 0.8-mm satin-finish stainless steel and fixed to the transformer using non-rusting screws. All etching shall be in black.

The Supplier shall provide lamacoid nameplates with black lettering engraved on a white background to identify all components in the control cabinet. Each lamacoid nameplate shall indicate the device number and function. Fuse nameplates shall also indicate the fuse rating.

3.4. TESTING AND TEST REPORTS

3.4.1. **Factory Tests**

Unless otherwise specified, the Supplier shall carry out the tests in accordance with CAN/CSA-C88.

Unless otherwise specified, the following tests shall also be performed on each transformer:

- Continuity and insulation resistance test of all control, current and protective wiring.
- Operating test to establish that control circuits function properly.
- Simulation of operating and trouble conditions to establish that all relays and meters function properly.
- Vacuum and pressure test of tank, OLTC compartment and radiators.
- ANSI Impulse test (BIL) on all terminals of all units.
- Measurement of positive and zero sequence impedances.
- Saturation curve from 10% to 110% of the rated voltage of the transformer at no-load (complete with current and losses readings).
- Power factor insulation measurement (Doble testing): Power factor and dissipation factors with relative capacitance values, for all winding combinations. A detailed report of capacitance and power factor tests made on all bushings shall be provided.
- SFRA (Sweep Frequency Response Analysis) measurement shall be performed on each unit with a Doble 5100 test set. Provided this test for both all dressed and in the shipping conditions.
- CT ratio and saturation measurements.
- Heat Run test at ONAN and ONAF ratings for the first unit only of each type. CT ratio and saturation measurements shall be repeated at the end of the heat run to confirm that they are still functioning correctly. A separate price shall be provided for the heat run test.

- Oil testing prior and after the heat run test, including dissolved gas analysis (DGA) results.

Each surge arrester shall have successfully passed all routine tests as per ANSI C62.11 as their manufacturer's location. In addition, they shall have successfully passed the following individual tests:

- Measurement of the discharge voltage with one 8 x 20 micro sec wave of 10 kA.
- Measurement of the leakage current at maximum continuous voltage on each part of the surge arrester with an oscillograph recorder. Specific complete test report shall be submitted for this type of equipment.

Manufacturer test reports in accordance with the applicable standards shall be provided for all ancillary equipment.

3.4.2. **Witnessing of Factory Acceptance Testing (FAT)**

The Purchaser reserves the right to witness any or all tests plus any quality control dielectric test performed, at no additional cost. Sufficient notification shall be given to allow Purchaser's Representative(s) to be present for the tests. A minimum of fifteen working days shall be allowed.

3.4.3. **Failure to Pass the Tests**

If the equipment fails to meet the test requirements of the standards, the Purchaser shall be notified immediately and reserves the right to refuse the equipment if the equipment fail against to successfully pass all test after the first repair.

3.4.4. **Test Reports**

All tests shall be documented, including test methods, environmental conditions, test results and all other pertinent information. Where applicable, the test reports shall identify pass/fail criteria and guaranteed values alongside the actual results.

Two copies of certified test reports are required and shall be provided to the Purchaser no later fifteen days after completion of the tests.

3.5. SHIPPING

3.5.1. **General**

The equipment shall be fully assembled, adjusted and thoroughly tested in the factory prior to shipping. Minimum disassembly will be done to accommodate shipping clearance restrictions. Whenever practical, a fully assembled unit shall be shipped.

3.5.2. **Impact Recorder**

At least two (2) 3-axis digital impact recorders complete with GPS tracking shall be mounted on each transformer tank at the most critical locations and kept operational during all transportation phases from the manufacturing plant, up to the final destination.

The Supplier shall provide all necessary software and cables required to interrogate the impact recorders upon arrival at site. Impact recorders reliant on mobile networks for interrogation shall not be acceptable.

4. DOCUMENTATION

4.1. TENDER SUBMITTALS

The following documents and drawings shall be submitted as part of the tender package:

- Catalogue data (mechanical and electrical)
- Preliminary description of operation
- Preliminary dimensional data (mechanical and electrical)
- General arrangement drawings
- Outline drawing complete with radiators
- Mechanical service requirements (water, air, etc)
- Electrical service requirements (approximate)
- Equipment delivery schedule
- List of recent similar installations

4.2. CONSTRUCTION SUBMITTALS

4.2.1. General

The Supplier shall provide a complete set of documentation and drawings for the transformer. The documentation and drawings provided shall be sufficient in quantity and quality to for the off-loading, assembly, installation, testing, commissioning, operating, routine and major maintenance, modification and disposal of the transformer throughout its lifetime.

The documentation and drawings shall be submitted as three separate packages:

- Approval documentation and drawings, for review and approval of the proposed design by the Purchaser prior to manufacturing.
- Fabrication documentation and drawings, used for manufacture by the Supplier, and for design of the installation by the Purchaser.
- As-built documentation and drawings, to provide a record of the transformer and ancillaries as manufactured and tested.

As a minimum, the Supplier shall submit the following documents and drawings with the various packages:

Document or Drawing	Approval	Fabrication	As-built
Nameplate drawing	X		
General arrangement drawings (including bill of materials and part numbers for ancillary equipment)	X	X	X
Foundation and support outline drawings	X	X	X
Electrical schematic diagrams	X	X	X
Electrical connection diagrams	X	X	X
Outline drawings and/or dimensional data sheets	X	X	X

Painting procedure specification	X	X	X
Control panel layout, including bill of materials and part numbers	X	X	X
Panel wiring diagrams	X	X	X
Certificate of compatibility of gaskets with oil	X	X	X
Bushing characteristics and layout drawings	X	X	X
Performance curves	X	X	X
Code test certificates (originals)		X	
Fall arrest system detail drawings and calculation note	X	X	X
Thermal damage curve	X	X	X
Installation, operating and maintenance manual	X		X
Manufacturer datasheets, installation instructions and manuals for ancillary equipment and control components	X	X	X
Inspection and test plan (ITP)	X	X	
Test reports for transformer			X
Test reports for ancillary equipment			X

4.2.2. **Timeline**

The package of approval documents and drawings shall be submitted within four weeks of the purchaser order being issued. These documents and drawings will be reviewed by the Purchaser within two weeks of receipt of the complete package and returned with comments to the Supplier.

The package of fabrication documents and drawings shall be submitted within eight weeks of the purchaser order being issued.

The package of as-built documents and drawings shall be submitted with two weeks of the factory acceptance tests being completed, and must be received by the Purchaser prior to the transformer arriving at site.

4.2.3. **Format**

The approval and fabrication documents and drawings shall be submitted electronically using the process described in this specification for electronic submittals.

Three paper copies of the complete as-built documentation and drawing package shall be assembled neatly into sets of binders, complete with table of contents and dividers for each section. Each set of binders shall include a CD-ROM with electronic copies of the complete as-built documentation and drawing package. The assembled as-built package shall be submitted using the process described in this specification for non-electronic submittals. An electronic copy of the as-built package shall also be submitted electronically using the process described in this specification for electronic submittals.

Drawings submitted electronically for review and approval shall be provided in Adobe PDF format. Fabrication drawings and as-built drawings submitted electronically shall be provided in Adobe PDF format and Bentley Microstation DGN format.

All other documentation submitted electronically for review, approval or fabrication shall be provided in Adobe PDF format.

YUKON ENERGY

S151-T1 TRANSFORMER

DATASHEET AND TECHNICAL QUESTIONNAIRE

Prepared by: Michael Tilbrook
Reviewed by: Not reviewed

File Number: 1826-08-02

REVISION LOG

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TABLE OF CONTENTS

1. Reference Data 4
1.1. Manufacturer 4
1.2. Type 4
1.3. Catalogue number or description 4
1.4. Conforming standards 4
2. Technical Data 4
2.1. Operating Conditions 4
2.2. Basic Characteristics 5
3. Construction 7
3.1. Bushing Details 7
3.2. Bushing current transformer 7
3.3. Cooling System 7
3.4. Insulating Liquid 8
3.5. Control Cabinet 8
3.6. Accessories 9
3.7. De-Energised Tap Changer (DETC) 11
3.8. Surge Arresters 11
3.9. Others 12
4. Weights, DIMENSIONS AND MISCELLANEOUS 13
4.1. Overall height 13
4.2. Overall width 13
4.3. Overall length 13
4.4. Height over cover 13
4.5. Weight of core and coils 13
4.6. Weight of tank and fittings 13
4.7. Weight of liquid (main tank, conservator and radiators) 13
4.8. Total volume of oil (main tank, conservator and radiators) 13
4.9. Total weight of complete transformer including conservator, radiators and oil 13
4.10. Maximum shipping weight (heaviest item) 13
5. Nameplates 13
5.1. Designed, built, and tested in accordance with CSA-C88 13
6. Tests 14
6.1. Routine tests in accordance with CSA-C88 14

6.2. Additional tests per CSA-C88 14

6.3. Surge Arresters tested in accordance with ANSI/IEEE C62.11 14

1. REFERENCE DATA

1.1. Manufacturer _____

1.2. Type _____

1.3. Catalogue number or description _____

1.4. Conforming standards _____

2. TECHNICAL DATA

2.1. Operating Conditions

2.1.1.	Cooling method			
2.1.2.	Average winding temperature rise	°C		
2.1.3.	Top oil temperature rise	°C		
2.1.4.	Operating temperature range	°C / °C		
2.1.5.	Rated primary voltage	kV rms		
2.1.6.	Rated secondary voltage	kV rms		
2.1.7.	Rated frequency	Hz		
2.1.8.	Rated capacity at voltage terminals at 55//65°C rise and nominal tap (primary and secondary windings):		At 30°C ambient (24h avg.)	At 0°C ambient (24h avg.)
	– ONAN	MVA	/	/
	– ONAF1	MVA	/	/
	– ONAF2	MVA	/	/

			ONAN	ONAF1	ONAF2
2.1.9.	Rated currents at ONAN, ONAF1, ONAF2 and nominal tap:				
	– Primary winding	A rms		/	/
	– Secondary winding	A rms		/	/

2.1.10.	Guaranteed positive sequence impedance Z_1 on rated MVA base (ONAN), at 75°C and nominal tap	%	
2.1.11.	Zero sequence impedance Z_0 on rated MVA base (ONAN), at 75°C and nominal tap	%	
2.1.12.	Guaranteed no-load losses at rated frequency and rated voltage on nominal tap, 75°C	kW	
2.1.13.	Guaranteed load losses at rated frequency and the following current on nominal tap, 75°C:		
	– At rated ONAN loading, 55°C rise	kW	
	– At rated ONAF1 loading, 55°C rise	kW	
	– At rated ONAF2 loading, 55°C rise	kW	

2.1.14. Exciting current at nominal tap:

– At 90% rated voltage	A rms	_____
– At 100% rated voltage	A rms	_____
– At 110% rated voltage	A rms	_____
– At 120% rated voltage	A rms	_____

2.1.15. Efficiency at rated frequency and the following current on nominal tap, 75°C:

– At rated ONAN loading, 55°C rise	%	_____
– At rated ONAF1 loading, 55°C rise	%	_____
– At rated ONAF2 loading, 55°C rise	%	_____

2.1.16. Regulation at ONAN rating and nominal tap:

– At 80% power factor	%	_____
– At 90% power factor	%	_____
– At 100% power factor	%	_____

2.2. Basic Characteristics

2.2.1. Winding configuration		_____
2.2.2. Winding material		_____
2.2.3. Winding type:		
– Primary		_____
– Secondary		_____
2.2.4. Thermally upgraded paper	Yes/No	_____
2.2.5. Vector grouping		_____
2.2.6. Rated impulse withstand voltage (BIL)		
Windings:		
– Primary winding	kV peak	
– Secondary winding	kV peak	_____
Bushings:		
– Primary bushings	kV peak	_____
– Secondary bushings (line)	kV peak	_____
– Secondary bushings (neutral)	kV peak	_____

2.2.7.	Rated power frequency withstand voltage (Applied voltage, 60 Hz-1 min)		
	Windings:		
	– Primary winding	kV rms	_____
	– Secondary winding	kV rms	_____
	Bushings:		
	– Primary bushings	kV rms	_____
	– Secondary bushings (line)	kV rms	_____
	– Secondary bushings (neutral)	kV rms	_____
2.2.8.	Rated induced voltage (≤ 500 pC):		
	– 7,200 cycles withstand	kV rms	_____
	– 60 minutes withstand	kV rms	_____
2.2.9.	Minimum corona inception voltages:		
	– Primary winding	kV rms	_____
	– Secondary winding	kV rms	_____
2.2.10.	Audible sound level:		
	– Without fans (ONAN)	dB	_____
	– With ONAF1 fans	dB	_____
	– With ONAF2 fans	dB	_____
2.2.11.	Maximum RIV at 1 MHz measured at 5% above rated voltage in accordance with ANSI C63.2	µV	_____
2.2.12.	Short circuit current withstand rating:		
	– Primary to secondary fault current at maximum steady state voltage	A rms sym.	_____
	– Maximum duration of rated short circuit withstand current	sec.	_____
2.2.13.	Type and grade of steel core lamination		_____
2.2.14.	Flux density of core at nominal voltage	Tesla	_____
2.2.15.	Vacuum that tank, conservator and coolers can withstand	kPa	_____
2.2.16.	Positive pressure that tank, conservator and coolers can withstand	kPa	_____

3. CONSTRUCTION

3.1. Bushing Details

3.1.1. Primary bushings:

- Manufacturer _____
- Leakage distance mm _____
- Rated current A rms _____
- Housing material _____

3.1.2. Secondary bushings (line):

- Manufacturer _____
- Leakage distance mm _____
- Rated current A rms _____
- Housing material _____

3.1.3. Secondary bushings (neutral):

- Manufacturer _____
- Leakage distance mm _____
- Rated current A rms _____
- Housing material _____

3.2. Bushing current transformer	Primary (LV)	Secondary (HV) Phase	Secondary (HV) Neutral
3.2.1. Quantity	_____	_____	_____
3.2.2. Ratio	_____	_____	_____
3.2.3. Accuracy:			
– Protection	_____	_____	_____
– Metering	_____	_____	_____
3.2.4. Service Factor	_____	_____	_____

3.3. Cooling System

3.3.1. Radiators:

- Manufacturer _____
- Model _____
- Number of radiator sections _____
- Oil temperature differential between input and output at 40°C ambient °C _____
- Rated capacity (per radiator) kW _____
- Radiator suitable for specified atmospheric pollution conditions Yes/No _____
- Crevice-free radiators Yes/No _____

3.3.2. Fans:

– Numbers of fans per radiator section		
– Total number of fans		
– Capacity of each fan	HP	
– Rated operating voltage	V rms	
– Number of phases/frequency	No. / Hz	
– Number of motor starters		
– Each motor starter padlockable	Yes/No	
– Starting current of each motor	A	

3.4. Insulating Liquid

3.4.1.	Manufacturer		
3.4.2.	Type		
3.4.3.	Meets ASTM D1275 Test for corrosive sulfur / copper sulfide deposition	Yes/No	
3.4.4.	Additional passivator required	Yes/No	
3.4.5.	Admissible operating range	°C / °C	/
3.4.6.	Total volume in main tank, conservator and radiators	L	
3.4.7.	Shipped in tanker	Yes/No	
3.4.8.	Bladder in conservator	Yes/No	
3.4.9.	Gaskets:		
	– Material		
	– Commercial name		
	– Temperature range	°C	
	– Compatible with oil supplied	Yes/No	

3.5. Control Cabinet

3.5.1.	Type NEMA-4X	Yes/No	
3.5.2.	Thermally insulated	Yes/No	
3.5.3.	Thermal insulation material		

3.6. Accessories

3.6.1. Gas detector relay:

– Manufacturer		_____
– Type		_____
– Number of gas accumulation alarm contacts (changeover type) available for Purchaser use		_____
– Number of oil flow/low oil trip contacts (changeover type) available for Puchaser use		_____
– Contact rating	A	_____

3.6.2. Liquid level gauge for main tank with low level alarm contacts:

– Manufacturer		_____
– Type		_____
– Number of individually adjustable high oil alarm contacts (change-over type) available for Purchaser use		_____
– Number of individually adjustable low oil alarm/trip contacts (changeover type) available for Purchaser use		_____
– Contact rating	A	_____
– 4-20 mA output signal wired to control cabinet	Yes/No	_____
– Operation down to -50°C ambient	Yes/No	_____

3.6.3. Winding temperature indicator (WTI):

– Manufacturer		_____
– Quantity		_____
– Type		_____
– Number of individually adjustable alarm/trip contacts (change-over type) available for Purchaser use		_____
– Contact rating	A	_____
– Setting for ONAF1 fans	°C	_____
– Setting for ONAF2 fans	°C	_____
– Setting for alarm	°C	_____
– Setting for trip	°C	_____
– 4-20 mA output signal wired to control cabinet	Yes/No	_____
– Operation down to -50°C ambient	Yes/No	_____

3.6.4. Top oil temperature indicator (OTI):

– Manufacturer		_____
– Type		_____
– Number of individually adjustable alarm/trip contacts (change-over type) available for Purchaser use		_____
– Contact rating	A	_____
– Setting for alarm	°C	_____
– Setting for trip	°C	_____
– 4-20 mA output signal wired to control cabinet	Yes/No	_____
– Operation down to -50°C ambient	Yes/No	_____

3.6.5. Pressure relief device:

– Manufacturer		_____
– Type		_____
– Quantity		_____
– Automatic resealing after operation	Yes/No	_____
– Manual reset semaphor	Yes/No	_____
– Number of trip contacts (changeover type) available for Purchaser use		_____
– Contact rating	A	_____
– Manual reset of trip contacts	Yes/No	_____
– Directional shroud and piping	Yes/No	_____
– Operation down to -50°C ambient	Yes/No	_____

3.6.6. Intelligent Transformer Incipient Fault Monitor :

– Manufacturer		_____
– Type		_____
– Transmitter		_____
– Auxiliary contacts		_____
– Communication port		_____
– Communication protocol		_____
– Operation down to -50°C ambient	Yes/No	_____

3.6.7.	Fall-Arrest System:			
	– Quantity of systems supplied			
	– Ultimate breaking load (hor./vert.)	kN / kN		/
	– Certified drawings and calculation note submitted for review prior to fabrication	Yes/No		
3.7.	**De-Energised Tap Changer (DETC)**			
3.7.1.	Manufacturer			
3.7.2.	Model			
3.7.3.	Range			
3.7.4.	Number of steps			
3.7.5.	Nominal current capacity	A rms		
3.7.6.	Location:			
	– Winding	Prim/ Sec		
	– End of winding	Phase/ Neutral		
3.7.7.	Impulse withstand voltage (full wave):			
	– Line end	kV peak		
	– Neutral end (if applicable)	kV peak		

3.8.	**Surge Arresters**		HV	LV
3.8.1.	Manufacturer			
3.8.2.	Class			
3.8.3.	Type			
3.8.4.	Catalogue number			
3.8.5.	Housing material			
3.8.6.	Arrestor voltage rating	kV rms		
3.8.7.	Arrestor maximum continuous operating voltage (MCOV)	kV rms		
3.8.8.	Guaranteed high current short duration withstand	kA crest		
3.8.9.	Guaranteed energy capability at 1.5 kA discharge	kJ		
3.8.10.	Housing creepage distance	mm		
3.8.11.	Arrestor height	mm		
3.8.12.	Guaranteed assembly cantilever strength	kN		

		HV	LV
3.8.13. Minimum arrester clearance for installation:			
– Phase to phase	mm		
– Phase to ground	mm		
3.8.14. Arrester mass	kg		
3.8.15. Terminal arrangement and cable connections			
Connectors for line terminal:		HV	LV
– Manufacturer			
– Catalogue no.			
– Type			
Connectors for ground terminal:		HV	LV
– Manufacturer			
– Catalogue no.			
– Type			
3.8.16. Components and accessories			
Discharge counter (HV):			
– Manufacturer			
– Catalogue no.			
– Type			
Insulating sub-base (HV):			
– Manufacturer			
– Catalogue no.			
– Type			
Remote transceiver (HV)	Yes/No		
Corona rings (HV)	Yes/No		

3.9. Others

3.9.1. Impact recorders (3-axis)		
– Quantity mounted on tank		
– Model		
– GPS tracking	Yes/No	

4. WEIGHTS, DIMENSIONS AND MISCELLANEOUS

4.1.	**Overall height**	mm	
4.2.	**Overall width**	mm	
4.3.	**Overall length**	mm	
4.4.	**Height over cover**	mm	
4.5.	**Weight of core and coils**	kg	
4.6.	**Weight of tank and fittings**	kg	
4.7.	**Weight of liquid (main tank, conservator and radiators)**	kg	
4.8.	**Total volume of oil (main tank, conservator and radiators)**	L	
4.9.	**Total weight of complete transformer including conservator, radiators and oil**	kg	
4.10.	**Maximum shipping weight (heaviest item)**	kg	

5. NAMEPLATES

5.1.	**Designed, built, and tested in accordance with CSA-C88**	Yes/No	

6. TESTS

6.1.	**Routine tests in accordance with CSA-C88**	Yes/No	
6.2.	**Additional tests per CSA-C88**		
6.2.1.	Continuity and insulation resistance (Megger) tests	Yes/No	
6.2.2.	Operating test on control circuits	Yes/No	
6.2.3.	Simulation of operating and trouble conditions	Yes/No	
6.2.4.	Vacuum and pressure test of tank	Yes/No	
6.2.5.	Impulse Tests (BIL) on all terminals of all units	Yes/No	
6.2.6.	Measurement of positive sequence impedance	Yes/No	
6.2.7.	Measurement of zero sequence impedance	Yes/No	
6.2.8.	Transformer saturation curve (10% to 110%)	Yes/No	
6.2.9.	Insulation power factor (Doble) tests	Yes/No	
6.2.10.	SFRA (Sweep Frequency Response Analysis)	Yes/No	
6.2.11.	Heat run test on nominal tap at ONAN, ONAF1 and ONAF2 ratings for the first unit only	Yes/No	
6.2.12.	Measurement of zero sequence impedance	Yes/No	
6.3.	**Surge Arresters tested in accordance with ANSI/IEEE C62.11**	Yes/No	

S151-T1 TRANSFORMER

SPECIAL TOOLS AND SPARE PARTS

Prepared by: Michael Tilbrook
Reviewed by: Not reviewed

File Number: 1826-08-02

REVISION LOG

Revision	Date	Amendment
00	2013/10/11	Initial issue

TABLE OF CONTENTS

1. Special Tools 3

2. Spare Parts 4

2.1. For One-Year Operation 4

2.2. For Three-Year Operation 5

2.3. For Five-Year Operation 6

1. SPECIAL TOOLS

The Tenderer recommends purchasing the special tools listed below at the tendered prices and for the delivery dates shown:

No.	Description	Qty	Unit Price	Total Price	Delivery

2. SPARE PARTS

The Tenderer recommends purchasing the spare parts listed below at the tendered prices and for the delivery dates shown. The prices shall remain valid for a period of 180 days and shall include delivery to site.

2.1. FOR ONE-YEAR OPERATION

No.	Description	Qty	Unit Price	Total Price	Delivery

2.2. FOR THREE-YEAR OPERATION

No.	Description	Qty	Unit Price	Total Price	Delivery

2.3. FOR FIVE-YEAR OPERATION

No.	Description	Qty	Unit Price	Total Price	Delivery

TOPIC:

REFERENCE: Page 12

PREAMBLE:

QUESTION:

a) Please provide the flowchart for an Executive Committee Screening for a YESAB review.

b) Please provide updates on Yukon Energy's schedule expectations of the YESAB and YUB processes.

c) What evidence of social license can Yukon Energy provide with respect to this Project?

ANSWER:

(a)

Please see Attachment 1 to this response.

(b)

Please see the response to YUB-YEC-1-1(b) and (c) for a review of YEC's schedule expectations regarding the YESAB process. With regard to the YUB process, the terms of reference provided by the Minister to the YUB provide guidance regarding expectations for this process and require the "YUB to submit its report and recommendations to the Minister of Justice no later than April 15, 2014."

(c)

Social license is evident with respect to this Project through the open discussions YEC has engaged in over several years with First Nations and the broader community, and what YEC has heard from these discussions.

In terms of stakeholders and the Yukon public, the F.A.R.E. principles (Flexibility, Affordability, Reliability and Environmental Responsibility) that were presented and adopted by participants of our March 2011 Energy Charrette provided the context for evaluating and proposing the LNG option at the charrette and in ongoing discussion thereafter.

There were 12 possible short-term (Year 2015) energy choices evaluated by the stakeholders involved in the day sessions of the charrette. Of the 12, LNG was 7th on the list that participants proposed. Diesel enhancement was 10th. Just as we are pursuing LNG, we have pursued or are pursuing all of the top six choices too:

1. Southern Lakes Winter Storage Enhancement (completing research, working with the public, stakeholders and First Nations);

2. Demand Side Management (currently Yukon Energy and Yukon Electrical Company Limited have a plan before the Yukon Utilities Board for review);

3. Wind (continuing to gather wind data on Tehcho, formerly Ferry Hill with an aim to have a shelf ready project);

4. Biomass (research has shown small scale biomass is not economically viable for Yukon Energy at this time, although we continue to support the Champagne and Aishihik First Nations in their research into a much smaller demonstration project);

5. Atlin Lake Hydro Enhancement (was explored but was taken off the table when the area was protected by the B.C. government);

6. Gladstone (still a hydro project we are interested in pending interest from the Kluane First Nation and the Champagne and Aishihik First Nations).

Note that for the year 2025, LNG was 2nd on the list from the people involved in the day time charrette.

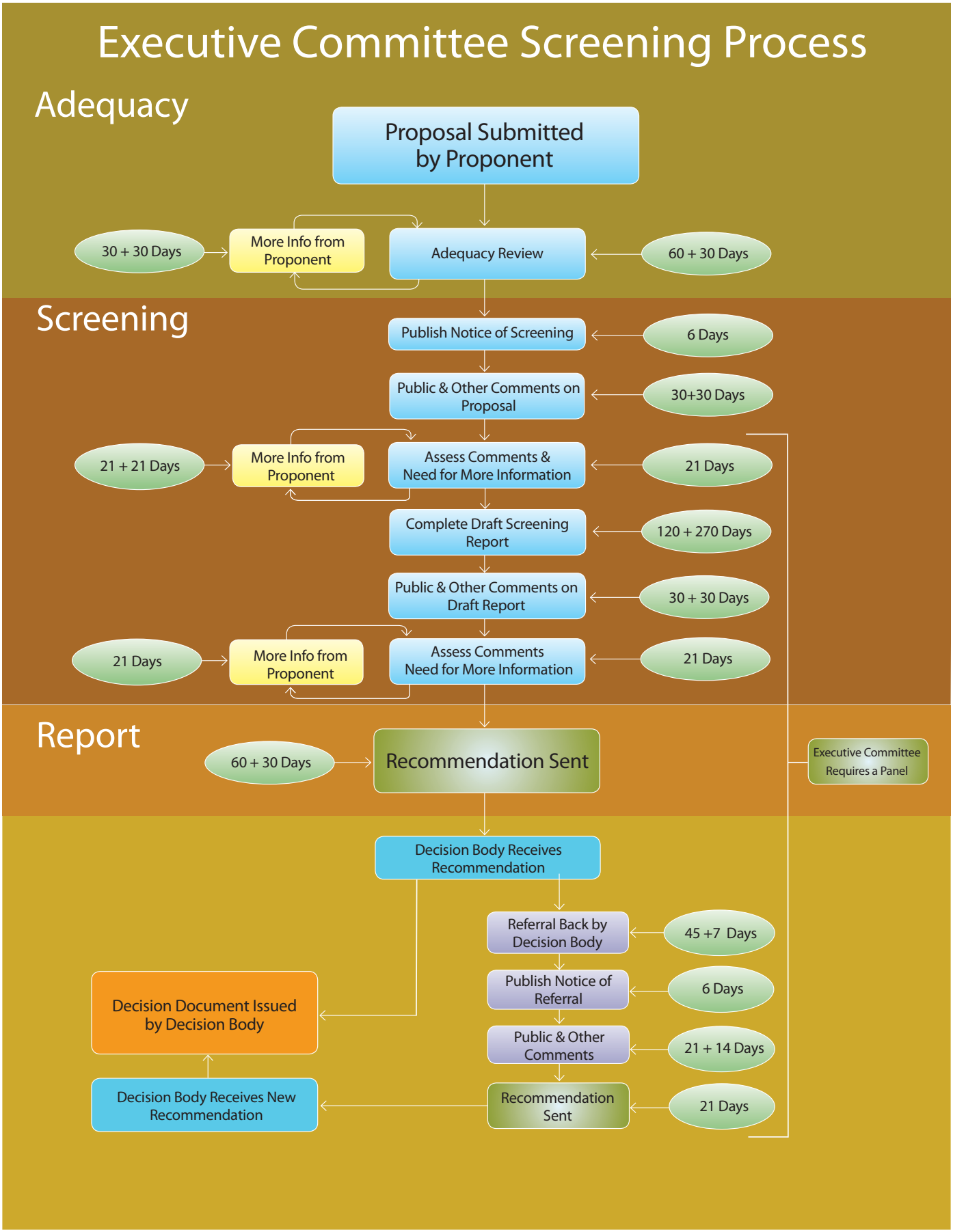
In short, before the charrette LNG was an option being looked at seriously by only one off grid new mine developer (who came to the charrette). However based on what we

heard from Yukoners at the three-day charrette, we agreed to look further into natural gas as a possibility and a follow up mini-charrette on LNG was held in January 2012.

Following the charrette, Yukon Energy conducted an assessment and found LNG to be a legitimate option to pursue as a cost-effective means of providing reliability and back-up capacity to replace aging diesel generation. We included LNG in our latest 20-year resource plan, which we presented to Yukoners via a number of public meetings and filed with the YUB during our 2012/2013 General Rate Application. Once we had made the decision to pursue LNG as a near term option, we held another round of public and stakeholder meetings (Summer 2013) to explain our decision and why we felt this was a good choice that was consistent with the F.A.R.E. principles.

From the very beginning we have also had interest and support from Yukon First Nations. After the mini-charrette on LNG, and long before YEC had made any decisions on the Project, in May 2012 we invited the two First Nations in whose traditional territory we are located to become partners in assessing the feasibility of the current Project. Not only has the Kwanlin Dün First Nation been a strong partner throughout this process (as was Ta'an until recently). Other First Nations made unsolicited proposals as well to participate in this project, including Dempster Energy Services (a consortium owned by the Na-Cho Nyak Dun Development Corporation, 40782 Yukon Inc. (Vuntut), Chief Isaac Corporation and Gwich'in Development Corporation) and the Dakwakada Development Corporation of the Champagne and Aishihik First Nations.

We recognize that social license is complex and ever changing. We also recognize that there are challenges inherent in adopting a new fuel source, new regulations, new permits, new technology, new supply chain, new skills etc. and that because of this, a collective "learning curve" among the proponents, regulators and stakeholders is inevitable.


Executive Committee Screening Process
Adequacy
Proposal Submitted by Proponent
30 + 30 Days
More Info from Proponent
Adequacy Review
60 + 30 Days
Screening
Publish Notice of Screening
6 Days
Public & Other Comments on Proposal
30+30 Days
21 + 21 Days
More Info from Proponent
Assess Comments & Need for More Information
21 Days
Complete Draft Screening Report
120 + 270 Days
Public & Other Comments on Draft Report
30 + 30 Days
21 Days
More Info from Proponent
Assess Comments Need for More Information
21 Days
Report
60 + 30 Days
Recommendation Sent
Executive Committee Requires a Panel
Decision Body Receives Recommendation
Referral Back by Decision Body
45 +7 Days
Publish Notice of Referral
6 Days
Public & Other Comments
21 + 14 Days
Recommendation Sent
21 Days
Decision Document Issued by Decision Body
Decision Body Receives New Recommendation

TOPIC:

REFERENCE: Page 13 re LNG vapourization equipment

PREAMBLE:

QUESTION:

a) Please provide a copy of the RFP, or RFEI, or tender documents, and copies of the relevant specifications used to solicit supplier options.

b) Please list the suppliers that responded and indicate who the successful supplier is and why they were selected.

ANSWER:

(a)

Please see response to YUB-YEC-1-29(a and b) for the general EPC tender process for all LNG facilities (including LNG storage tanks, vapourizer and other related equipment) and a review of outcomes of this tender, the cancellation of the tender based on the results, and the subsequent process of contractor selection.

(b)

The list of suppliers that responded is confidential and cannot be shared. The successful supplier is GP Strategies. Please see response to YUB-YEC-1-29(a and b).

TOPIC:

REFERENCE: Page 14

"In summary, the Project, including mitigation measures set out in the project proposal, is not expected to cause any likely significant adverse effect...This conclusion reflects careful consideration of the Project design as well as the consideration of mitigation measures that reduce or eliminate potential adverse effects."

PREAMBLE:

QUESTION:

a) Please confirm that this is still Yukon Energy's view.

b) Please confirm that YESAB received submissions that provided perspectives that differ from Yukon Energy's view.

ANSWER:

(a)

Confirmed.

(b)

Confirmed.

TOPIC:

REFERENCE: Page 14

"... the project is expected to provide for reduced greenhouse and particulate emissions in the project study area..."

PREAMBLE:

QUESTION:

a) Please describe the "project study area" and please confirm that this perspective does not take into account the greenhouse gas (GHG) emissions outside the project study area.

b) Please confirm that there are submissions to YESAB that provide documented alternative perspectives that indicate that the GHG emissions within the project study area would be higher from burning natural gas than from diesel when methane's global warming potential is considered over a 20 year timeframe.

c) Please confirm that there are submissions to YESAB that provide documented alternative perspectives that indicate that the cradle to grave GHG emissions (i.e., lifecycle emissions from upstream activities including natural gas extraction, processing, liquefaction and transportation) from burning natural gas are worse than diesel's lifecycle GHG emissions, when methane's global warming potential is considered over a 20 year timeframe.

d) According to media reports (see attached article from the New York Times) methane leaks may negate earlier claims that burning natural gas may produce less greenhouse gas emissions than burning diesel. Please comment on these reports.

e) Is it Yukon Energy's understanding that the Yukon Government Climate Change Action Plan intends, in effect, to "export" emissions to other jurisdictions? If not, why does Yukon Energy's GHG emissions totals not include out of territory impacts?

f) Has Yukon Energy received any formal or informal instruction or direction from the Yukon government or from Yukon Development Corporation with respect to valuing renewable energy relative to fossil fuel generation? If so please explain this direction, and if in writing provide copies of the written instruction or direction.

ANSWER:

(a), (c), and **(e)**

Chapter 3 of the YESAB Project Proposal outlines the definition of the broader Project Study Area for examining potential environmental and socio-economic effects of the Project on Valued Environment and Socio-economic components of the environment. The Project Study Area was defined for most Valued Components as a 500 metre radius surrounding the Project Construction Footprint, as the maximum geographic extent of most likely environmental and socio-economic effects is expected to be included in this area, excluding effects on air quality and noise which will disburse in some instances more broadly than the Project Study Area, and excluding various positive socio-economic effects which will extend throughout Yukon (e.g., ratepayer savings).

With regard to air quality a broader 5 km radius was selected for the purposes of assessing potential cumulative effects with other Projects that may be outside the Project Study Area but that may have effects that overlap spatially and temporally with the effects of the Project. Accidents and malfunctions related to safety/transportation of LNG within Yukon considered an expanded regional scale to encompass fuel transport within Yukon from the British Columbia border southeast of Watson Lake to Whitehorse.

It is confirmed that during the YESAB review process a number of interested parties have submitted their perspectives regarding the need to consider lifecycle emissions from upstream activities including natural gas extraction, processing, liquefaction and transportation potentially being greater than diesel. YEC presented information on these issues during its public open house during July 2013, prior to filing its YESAB Project Proposal (see YEC's YESAB Project Proposal, Chapter 4 and related appendices, including reference to YEC making available on its web site two separate life-cycle assessments regarding LNG).

With regard to assessing upstream activities outside of Yukon, it is noted that on December 9, 2013, YESAB issued a letter that indicated that the Executive Committee

will not include natural gas extraction, processing, and liquefaction in the scope of the Project as these activities occur outside of Yukon and thus are beyond the authority of the Executive Committee to consider; the letter also stated that the Executive Committee also will not consider hydraulic fracking in Yukon in the assessment of the Project (as this is not the LNG supply source identified in the Project proposal, and the possibility of hydraulic fracking as an activity connected to this Project is simply too remote and speculative for the Executive Committee to include it in its assessment.

(b)

Confirmed that such other submissions were made to YESAB.

Please see response to CW-YEC-1-1(i) which provides Table A-1 that was filed by YEC with YESAB as a response to information requests R17 and R18 (the table in the response is the update filed in January 2014). This table provides total mass emissions for PM, CO2, CH4 and NO2 as well as CO2-equivalent for natural gas and diesel combustion[1]. The table includes global warming potential multipliers for 20-year and 100 year timeframe which were obtained from the IPCC 5th assessment report (2013). Table A-1 indicates that whether global warming multipliers for 20-year or 100-year timeframe are used, it does do not change the results of the air quality assessment.

(d)

The information request does not relate to information prepared by, or relied upon by, Yukon Energy in relation to the proposed Project. YCS/LE may file its own evidence following the processes outlined in the Board's rules of practice and procedure.

(f)

Please see response to (a) above. Yukon Energy has received no formal or informal instruction or direction from the Yukon government or from Yukon Development Corporation with respect to valuing renewable energy relative to fossil fuel generation.

[1] As noted in the response to R17, when information was not available, emission factors for a given constituent were taken from the U.S. National Renewable Energy Laboratory Life Cycle Inventory Database (NREL LCI Database), similar to the approach taken by the Pembina Institute as part of the life cycle emissions inventory (2013).

TOPIC:

REFERENCE: Page 17

"...In 2012, 99% of the generation on the Yukon's Integrated Grid was from renewable sources such as hydro and wind"; also Page 18 and Footnote 19

PREAMBLE:

QUESTION:

a) What was the actual load in 2012 in GWh and please state what portion of this load would have been provided from long term average hydro power generation, and please state the actual hydro energy provided?

b) Please confirm that electrical rates in 2012 were based on long term average hydro generation as per YUB order.

c) Please confirm that the diesel contingency fund (DCF) has been or will be credited with the cost savings related to the higher than long term average hydro energy that served the actual load.

d) Please provide the annual energy produced by each of the Whitehorse Rapids hydro plant, the Aishihik hydro plant, and the Mayo hydro plant for each of the past 5 years (2009-2013).

e) How much energy did the Vestas wind turbine generate in each of the past 5 years and what capacity factors do these represent?

f) Please provide the annual energy produced by diesel generation and the actual cost for this generation in each of the past 5 years.

ANSWER:

(a)

Actual grid generation (including Fish Lake hydro) in 2012 was 427.9 GW.h. At this load, and based on the approved 2012 GRA for YEC, long-term average YEC and Fish Lake hydro generation is estimated 412.1 GW.h.

Actual YEC and Fish Lake hydro generation in 2012 was 424.4 GW.h

(b)

Confirmed as regards the revenue requirement as approved by the Board in 2013. Board Order 2013-1 directed YEC to include (in forecast revenue requirement and approved rates) provision for diesel generation costs forecast at 100% LTA hydro generation for each test year.

(c)

YEC can confirm that this is its understanding as to what has occurred in the past with the DCF and what YEC would expect to occur in the future with the DCF.

The revised Diesel Contingency Fund, however, has not yet been approved by the Board. In correspondence to the Board dated July 5, 2013, Yukon Energy noted that actual diesel generation in 2012 was 2,683 MW.h, well below "expected" diesel generation of 15,261 MW.h at 100% long term average hydro generation as estimated for actual 2012 grid generation requirements (i.e., YEC's actual hydro generation was correspondingly higher than long term average).

In July 16, 2013 correspondence to Yukon Energy, the Board directed that the additional earnings of $3.714 million that were identified by YEC as a deferred payment to the DCF be transferred to the DCF on an interim basis pending final resolution of the matter.

YEC has accordingly deferred $3.714 million of payments to the DCF (costs to YEC, amount owing to ratepayers), in order to reflect the difference in costs (at approved diesel fuel prices) between actual and expected diesel generation in 2012.

(d)

Annual energy generated at the Whitehorse Rapids hydro plant, the Aishihik hydro plant and the Mayo hydro plant for the past 5 years (2009-2013) is presented in Table 1 below.

Table 1:
Annual Generation at YEC Hydro Plants
For 2009-2013 Period

Year	Whitehorse Hydro [GWh]	Aishihik Hydro [GWh]	Mayo Hydro [GWh]
2009	223.8	118.7	28.5
2010	233.8	111.7	31.5
2011	231.5	132.3	20.6
2012	230.2	143.3	49.7
2013	221.3	138.0	62.0

(e)

Please see Table 2 below.

Table 2:
Vestas Wind Turbine Annual Generation for
2009-2013 Period and Associated Capacity Factor

Year	WW2 [MWh]	Capacity Factor [%]
2009	129	2%
2010	11	0.2%
2011	396	7%
2012	445	8%
2013	278	5%

(f)

Please see Table 3 below (includes all YEC diesel generation on the grid, including generation for capital projects or RFID - please see UCG-YEC-1-5(c) for the portion of this diesel generation at WTGS for some of these years).

Table 3:
Annual Thermal Generation for
2009-2013 Period and Associated Fuel Costs

Year	Diesel Generation	Diesel Fuel Cost
	[GWh]	[$Million]
2009	2.6	$0.6
2010	5.1	$1.3
2011	15.9	$4.4
2012	3.1	$0.9
2013	1.9	$0.6

TOPIC:

REFERENCE: Page 17

"...Yukon's isolated grid has no access to external North American power grids to secure extra power when it is needed, or to sell surplus renewable generation when it occurs" and "…the Project will… and stimulate oil product-natural gas conversions in other sectors."

PREAMBLE:

QUESTION:

a) Please confirm that Yukon Energy has secondary sales customers within Yukon to which surplus renewable energy could be sold.

b) Does Yukon Energy have any programs either within or outside the proposed DSM plan to sell secondary energy when available? If so on what time scales (hourly, daily, weekly, etc.)?

c) In Yukon Energy's 2011 20-Year Resource Plan update did Yukon Energy consider the potential for secondary sales when assessing non-hydro renewable resource options such as wind? If not why not?

d) Please describe from where and when YEC received direction to "stimulate oil product-natural gas conversions in other sectors"?

e) What is YEC's plan to stimulate oil product-renewable energy conversions in other sectors?

ANSWER:

(a)

Confirmed. Yukon Energy has one secondary sales customer located in Mayo. All other secondary sales customers are customers of YECL.

(b)

Secondary sales are currently made available to qualifying customers according to the terms as set out in Rate Schedule 32.

(c)

Secondary sales were not considered in the 2011 Resource Plan analysis for any of supply options considered.

As noted in the 2012/2013 GRA, continued non-industrial and industrial growth has effectively depleted the surplus hydro available since the 1998 Faro mine shut down, and the Yukon grid has reached the point today of requiring diesel generation to supply a growing share of new grid load under long-term average water conditions. Under such conditions, Yukon Energy cannot assume or forecast secondary sales being available on any ongoing basis (beyond short term forecasts of 12 to 18 months, subject to various risks and uncertainties).

(d) and **(e)**

Yukon Energy did not receive direction to "stimulate oil product-natural gas conversions in other sectors" of the Yukon and has no plans in this regard. The reference at page 17 of the Application is simply describing one of the potential or likely outcomes of introducing an LNG supply chain and making LNG available in Yukon.

TOPIC:

REFERENCE: Page 18

"... For future consideration when long term loads can justify such developments, Yukon Energy is also pursuing a wind development that could range up to 20 MW at Techo ..." In Yukon Energy's 2011 20-Year Resource Plan update wind energy projects of both 10.5 and 21 MW were examined.

PREAMBLE:

QUESTION:

a) For each of the 4 load scenarios presented in Appendix C/Attachment C Table C-2, please recalculate the levelized cost of energy (LCOE) from each of these two wind project sizes assuming that such projects could commence operation in the fall of 2017 and using long term average water availability. Please provide, by year, the fossil fuel generation displaced and the "surplus" wind energy (would result in "spilled" hydro energy if not curtailed).

b) Please repeat (a) above substituting the driest 5 year period on record (1996 to 2000) for the years 2025 to 2029 in the analyses.

c) How would the LOCEs in (a) and (b) above change if one-half of the "surplus" wind energy could be sold at the present secondary sales rate?

d) At what load level and fossil fuel generation requirement in each of the four load forecast scenarios presented in Appendix C/Attachment C would Yukon Energy consider that it is worth adding new renewable generation? Please provide examples and LCOE pricing targets that Yukon Energy would use.

ANSWER:

(a) through **(d)**

As noted in the Application, YEC's 2011 Resource Plan provided detailed assessment of all potential resource options, including the 21 MW wind farm option at Techo. Based on this earlier analysis, YEC has no basis today in the context of the current Application review by the YUB to re-examine the Techo project as requested here. Specifically, based on the outcomes of the earlier analysis, there is no basis now to re-examine the capital intensive Techo project in the context of current load forecasts that are much lower than the Scenario A load forecast used to assess this project in the 2011 Resource Plan (when the project was a high cost option with even the earlier forecasts). Similarly, there is no basis to examine any project's feasibility in the context of an LCOE analysis which assumes that the driest five year period of record would re-occur during a specific future time period such as 2025 to 2029.

Please see YUB-YEC-49(c) for a review of prior information on Techo wind project costs in the context of the current diesel-gas conversion Project. Please also see YSC/LE-YEC-1-59(a), Attachment 1 for additional review of the wind project economics as examined in the 2011 Resource Plan.

TOPIC:

REFERENCE: Page 19

"...thermal generation will continue to provide reliable energy supply on the Yukon grid until new renewable energy options are brought on line and used to displace energy that would otherwise need to be generated from fossil fuels." and "... As the requirement for default diesel generation increases, Yukon Energy will continue to assess the economics of developing additional renewable energy supply options..."

PREAMBLE:

QUESTION:

a) Please confirm that the variable cost of LNG generation would be in the order of $0.165 per kWh ($0.135 for fuel plus $0.03 variable O&M) and that the variable cost of generation form new diesel units would be in the order of $0.276 per kWh ($0.246 for fuel and $0.03 variable O&M). If not confirmed please provide the applicable variable costs.

b) If the LNG generation project is installed as proposed and the energy cost is as projected by Yukon Energy, would new renewable energy options be developed when economic compared to the variable LNG generation cost or when compared to the variable diesel generation cost? Please explain fully.

ANSWER:

(a)

YEC cannot confirm variable O&M cost at $0.03 per kW.h for diesel or gas generation.

Variable O&M at 1.6 cents were adopted in the 1996/97 GRA for runoff rate and DCF calculations for WAF, including provision for ongoing maintenance averaged over diesel unit generation levels. Although an 'incremental O&M cost' of 3 cents/kW.h was adopted for the 2009 Phase II filings, this number was not based on short-term incremental costs applicable to YEC and no such updated cost information has been developed or

reviewed at this time. The 2011 Resource Plan assumed diesel O&M costs at about 3 cents/kW.h for old units and 2 cents/kW.h for new units - see 2011 Resource Plan, Appendix E, Attachment E2.

(b)

YEC cannot specify today all the factors that may be considered in future when assessing each specific new renewable energy project option. However, when assessing the economic and financial cost impacts for ratepayers of each new renewable energy option, the future assessment will need to compare expected costs with and without the new renewable energy options - and to the extent that variable LNG costs are saved by the new renewable option (rather than variable diesel costs), then these variable LNG costs will need to be used in the ratepayer impact assessment.

TOPIC:

REFERENCE: Page 20

"The Overview of Yukon Energy's 2011 20-Year Resource Plan: 2011-2030 reviewed the variability in actual hydro and diesel generation on the grid between years, and within each year, due to variability in water availability, and how this highlights the need for reliable and flexible thermal generation to accommodate this variability."

PREAMBLE:

QUESTION:

a) Please describe what Yukon Energy is doing to reduce this vulnerability to variations in water availability.

b) Is Yukon Energy seeking non-hydro renewable resources to diversify its portfolio of supply projects? If so what are they and when are they projected to come on-stream?

c) Is Yukon Energy seeking out potential new hydro projects with particular characteristics or attributes? If so what are the particular attributes that Yukon Energy is seeking and what potential projects have these attributes?

ANSWER:

(a) (b) and (c)

Yukon Energy reviewed at length all available resource options in its 2011 Resource Plan, including the implications of different possible portfolio options in light of Yukon's isolated grid, specific loads scenarios, and potential options relevant to grid electricity generation planning. The Application has provided any updates that are available today on these matters that are potentially relevant to the Board's review of the Project in accordance with the Minister's terms of reference.

TOPIC:

REFERENCE: Page 20

"In 16% of the 31 water years (i.e., five years, reflecting for this load scenario the worst drought conditions in five consecutive years from 1996 -2000), diesel generation at the Base Case 2016 forecast load is estimated to range from 52.8 GWh to 101.4 GWh (i.e., 2 to more than 4 times the long term average at this load level)."

PREAMBLE:

QUESTION:

a) For each of these five driest years please list the actual monthly and annual inflows of each of Whitehorse Rapids, Aishihik, and Mayo hydro plants as well as the monthly and annual long term averages for each of the three hydro plants.

b) For each of the three hydro plants please provide a table showing the net annual water volume and stored energy drawdown in each of these 5 years. If there is no net drawdown of stored water and energy (from Aishihik and Mayo Lakes in particular) incorporated into the diesel generation numbers quoted please explain why.

c) What is the maximum useable water and energy storage in Aishihik Lake permitted in the present water use license?

ANSWER:

(a) and **(b)**

Please see Attachment 1 to this response.

Please note that as the request was to provide the annual numbers for the water years from 1996 to 2000, therefore long-term average generation is not provided.

As the table in Attachment 1 shows, there is hydro generation from Mayo and Aishihik generation stations for those drought years. The lake levels are affected by inflows, outflows and other factors (such as evaporation and ice build-up); therefore, YEC cannot provide net annual water levels for those years.

(c)

Based on the current license, which expires on December 31, 2019, the mean daily water level on Aishihik Lake should be maintained between a controlled minimum of 913 m and a controlled maximum of 915.16 m. The lake operation is also subject to minimum water flow rates as well as maintaining water levels in spring based on a 10-year rolling averages.

Average Inflows Available for Outflow (IAO) and Average Generation

		Whitehorse Rapid GS		Aishihik GS		Mayo GS	
		Marsh Lake - monthly average IAO (cms)	Average generation (GW.h)	Aishihik Lake - monthly average IAO (cms)	Average generation (GW.h)	Mayo Lake - monthly average IAO (cms)	Average generation (GW.h)
1996	Jan	60.9	18.2	1.5	3.2	2.3	8.5
	Feb	58.9	16.4	2.8	6.6	2.1	5.4
	Mar	51.3	17.0	2.0	4.8	1.2	2.4
	Apr	39.9	11.8	4.6	7.0	2.6	1.5
	May	101.7	16.3	8.5	5.9	19.8	5.8
	Jun	343.8	20.9	4.0	2.5	44.0	6.3
	Jul	486.1	23.2	15.1	2.5	15.7	3.6
	Aug	413.3	24.5	13.1	2.5	10.2	3.4
	Sep	340.2	26.9	5.8	3.1	17.6	3.0
	Oct	198.0	26.6	1.9	4.3	7.7	5.6
	Nov	110.7	18.1	5.2	14.4	4.1	8.2
	Dec	74.1	17.7	2.9	17.7	4.9	8.2
Annual Average IAO and total annual generation		**189.9**	**237.6**	**5.6**	**74.7**	**11.0**	**61.9**
1997	Jan	51.0	18.2	4.4	11.1	3.7	8.5
	Feb	46.4	12.3	2.3	6.1	2.7	5.9
	Mar	30.3	10.1	1.2	3.9	1.8	3.0
	Apr	36.0	9.9	2.8	5.2	4.9	2.3
	May	160.6	14.7	15.4	5.7	51.1	8.8
	Jun	440.6	19.7	19.9	2.8	49.2	7.2
	Jul	566.9	19.6	16.3	2.5	28.9	7.2
	Aug	549.2	20.4	19.6	2.6	26.8	7.5
	Sep	464.7	23.3	10.9	2.7	16.3	7.0
	Oct	261.4	25.5	3.8	4.4	10.7	6.7
	Nov	151.9	18.1	4.5	14.4	4.3	8.2
	Dec	102.3	17.7	6.1	17.1	4.9	8.2
Annual Average IAO and total annual generation		**238.5**	**209.5**	**8.9**	**78.6**	**17.1**	**80.4**
1998	Jan	69.0	18.2	6.0	16.6	4.3	8.5
	Feb	58.4	16.4	1.0	9.3	2.8	6.7
	Mar	32.8	17.2	1.5	6.6	3.5	3.8
	Apr	32.3	10.8	3.7	7.2	3.5	2.1
	May	95.0	15.8	8.3	4.6	25.5	6.9
	Jun	557.6	22.9	13.5	2.6	27.1	4.3
	Jul	446.4	23.5	2.9	2.5	8.0	3.4
	Aug	414.0	24.6	-0.6	2.5	4.2	3.4
	Sep	328.8	27.1	2.0	2.8	6.4	2.8
	Oct	222.5	26.5	0.3	3.4	4.7	5.7
	Nov	164.1	18.1	-0.6	5.1	2.4	6.3
	Dec	85.7	17.7	0.5	3.9	2.5	1.4
Annual Average IAO and total annual generation		**208.9**	**238.9**	**3.2**	**67.1**	**7.9**	**55.3**

Average Inflows Available for Outflow (IAO) and Average Generation

		Whitehorse Rapid GS		Aishihik GS		Mayo GS	
		Marsh Lake - monthly average IAO (cms)	Average generation (GW.h)	Aishihik Lake - monthly average IAO (cms)	Average generation (GW.h)	Mayo Lake - monthly average IAO (cms)	Average generation (GW.h)
1999	Jan	66.3	18.2	2.6	3.2	3.5	1.3
	Feb	55.3	16.4	0.4	3.0	2.1	1.8
	Mar	33.8	13.7	0.0	3.2	2.0	1.3
	Apr	22.6	9.9	0.9	3.1	3.7	1.5
	May	90.6	14.8	8.6	2.6	33.1	8.0
	Jun	455.6	19.8	23.0	3.8	44.1	6.0
	Jul	498.0	23.3	20.3	2.5	14.5	3.6
	Aug	464.9	24.0	9.5	2.5	14.7	3.9
	Sep	343.9	22.3	5.1	2.7	23.6	8.0
	Oct	222.1	25.0	3.1	4.1	13.7	7.2
	Nov	152.9	18.1	3.0	11.8	4.3	8.2
	Dec	115.4	17.7	3.3	11.2	4.1	8.2
Annual Average IAO and total annual generation		**210.1**	**223.2**	**6.6**	**53.7**	**13.6**	**58.9**
2000	Jan	107.2	18.2	1.3	5.8	2.1	8.5
	Feb	70.3	16.4	2.7	6.8	3.7	6.6
	Mar	43.2	18.3	1.9	5.8	2.2	3.4
	Apr	35.8	18.0	2.8	5.7	1.8	1.6
	May	96.8	15.5	10.8	4.3	30.4	7.9
	Jun	461.6	19.0	29.6	3.9	59.8	6.8
	Jul	662.5	16.8	43.2	7.1	26.4	5.5
	Aug	522.2	15.0	53.6	9.7	29.8	5.7
	Sep	407.2	16.0	50.4	11.1	25.3	5.9
	Oct	318.4	18.0	20.8	13.4	19.3	5.1
	Nov	178.3	18.0	9.0	14.5	10.3	7.8
	Dec	118.7	17.7	6.0	16.3	4.2	8.2
Annual Average IAO and total annual generation		**251.9**	**206.9**	**19.3**	**104.5**	**17.9**	**73.1**

Notes:

1. The monthly average inflows available for outflows are estimated based on weekly average numbers and subject to rounding.

2. The inflows available for outflow are estimated based on recorded outflows and change in lake levels for each lake. IAOs are affected by evaporation from a large reservoir and the magnitude of water lost from evaporation could exceed the amount gained by precipitation and inflow of the river that flows into the reservoir; and in the winter months due to ice build-up in shorelines [ice hung-up in shallow zones] which would prevent the water to be included as available storage to be released; and other factors.

3. The generation estimates are based on Base Case no Alexco load forecast for 2016 at 437.3 GW.h.

TOPIC:

REFERENCE: Page 21

"... The long-term average forecast, for example, shows very low expected or long-term average diesel generation during about five months of the year (late May to late October) under each of the load scenarios. ..."

PREAMBLE:

QUESTION:

a) This statement implies that there periods of surplus of hydro capacity and energy during the specified period of time. Please indicate Yukon Energy's plans with respect to secondary sales during the period late May to late October to obtain the maximum possible revenue for the benefit of all ratepayers?

b) Please verify that secondary sales, by requirement, displace fossil fuel use and therefore secondary sales would result in reduced GHG emissions within Yukon.

ANSWER:

(a)

Please note that the statement quoted referred to long-term averages - in any given year, YEC may not have surplus hydro during these same periods, i.e., during drought periods when stored water must be augmented or retained for winter use and/or summer flows are reduced. Notwithstanding these constraints, Yukon Energy continues to retain secondary sales rates available to customers.

During 2014, YEC is completing a detailed internal review of load forecasts and reservoir levels to determine exactly how much water is potentially available for near-term secondary sales. Additionally, a market review will be undertaken internally to see if any opportunities exist to expand this program to new customers. The success of this initiative is entirely dependent on the economics (i.e. capital cost versus forecast water availability).

(b)

Confirmed.

TOPIC:

REFERENCE: Page 21

"... A related implication is that the expected life of the thermal generation facilities on the grid will tend to be materially longer than would be expected with higher levels of annual use."

PREAMBLE:

QUESTION:

a) For each of the four load forecasts provided in Appendix C/Attachment C, please provide a list by year for the 40 year period starting in 2015, of annual operating hours expected from the natural gas-fired generators proposed in the applied for project.

ANSWER:

(a)

The following annual operating hours are estimated for the years 2015 to 2018 based on forecasts diesel displacement by gas units under long-term average hydro assumptions in Table 4-3 (assumes two units added by start of 2015 and a third unit currently forecast to be added by start of 2017 - for all forecast scenarios other than the Base Case [and for all 2018 estimates], also assumes potential diesel displacement without attempting to do analysis equivalent to that provided in Appendix D for the Base Case in 2015 to 2017, and assuming operation of all units at full capacity, i.e., operation at less than full capacity would require correspondingly more annual operating hours):

- **2015**:
  - **Load Scenarios without Alexco**: 17.0 GW.h annual generation for 2 engines (8.75 MW) indicates operation for about 22% of the available annual hours (about 1937 hours per engine per year).
  - **Load Scenarios with Alexco**: 25.7 GW.h annual default diesel generation, with 92% of this displaced by generation for 2 engines (8.75

MW) indicates operation for about 31% of the available annual hours (about 2702 hours per engine per year).

- **2016**:
  - **Load Scenarios without Alexco**: 22.9 GW.h annual default diesel generation, with 95% of this displaced by generation for 2 engines (8.75 MW) indicates operation for about 28% of the available annual hours (about 2486 hours per engine per year).
  - **Load Scenarios with Alexco**: 33.1 GW.h annual default diesel generation, with 85% of this assumed to be displaced by generation for 2 engines (8.75 MW) indicates operation for about 37% of the available annual hours (about 3215 hours per engine per year).

- **2017**:
  - **Load Scenarios without Alexco**: 26.9 GW.h annual default diesel generation, with 100% of this displaced by generation for 3 engines (13.1 MW) indicates operation for about 23% of the available annual hours (about 2050 hours per engine per year).
  - **Load Scenarios with Alexco**: 37.6 GW.h annual default diesel generation, with 95% of this assumed to be displaced by generation for 3 engines (13.1 MW) indicates operation for about 31% of the available annual hours (about 2728 hours per engine per year).

- **2018**:
  - **Base Case**: 31.4 GW.h annual default diesel generation, with 100% of this assumed to be displaced by generation for 3 engines (13.1 MW) indicates operation for about 27% of the available annual hours (about 2395 hours per engine per year).
  - **Base Case with Alexco**: 42.8 GW.h annual default diesel generation, with 92% of this assumed to be displaced by generation for 3 engines (13.1 MW) indicates operation for about 34% of the available annual hours (about 3007 hours per engine per year).
  - **Scenario A1 - Base Case with Carmacks Copper (no Alexco)**: 68.9 GW.h annual default diesel generation, with 85% of this assumed to be displaced by generation for 3 engines (13.1 MW) indicates operation for about 51% of the available annual hours (about 4471 hours per engine per year).

- **Scenario A2 - Base Case with Carmacks Copper (with Alexco)**: 81.8 GW.h annual default diesel generation, with 80% of this assumed to be displaced by generation for 3 engines (13.1 MW) indicates operation for about 57% of the available annual hours (about 4995 hours per engine per year).

As the above analysis progresses to address higher load years or scenarios, the assessments become less useful absent additional consideration of Appendix D types of analysis as well as potential impacts from blended fuel options that may by then be implemented at WTGS.

The forecasts in Appendix C indicate growing default diesel requirements after 2018 for the Base Case, and swings in these requirements under other scenarios between 2019 and 2025 depending on mine connections. However, the requested analysis is not useful beyond 2018 when it becomes necessary under the Base Case to consider the need for new natural gas generators to be added in response to new capacity shortfall requirements, i.e., whatever additions are made would change the assessment of hours of operation for the initial three engines. Accordingly, no attempt is made to extend this analysis beyond 2018 to 2030. Please see response to CW-YEC-1-10(c) for consideration as to potential future gas unit requirements after 2018.

As regards providing forecasts beyond 2030, please see response to YCS/LE-YEC-1-35 (a).

TOPIC:

REFERENCE: Page 22 and Table 4-2

PREAMBLE:

QUESTION:

a) Please confirm that the forecast new peaking requirements assumes no new YECL grid-connected diesel generating capacity such as the 2 MW diesel generator YECL wishes to install in Carcross.

ANSWER:

(a)

Please see footnote 31 of page 24 of the Application which notes as follows regarding the proposed 2 MW diesel generation YECL wishes to install in Carcross:

> YECL proposed, in its recent GRA, a 2 MW new diesel engine on the grid at Carcross at a cost of $3 million. The sole purpose of this project, if developed, is to provide back-up for Carcross and Tagish area customers in the event of loss of power from the grid, i.e., the YECL project is not an alternative to the need for YEC to replace retired thermal capacity at Whitehorse. Costs of this YECL project have yet to be approved by the YUB to be recovered in rates. Given the earliest timing for this project (2015) and its small size, its development (if approved by the YUB) will not affect the required timing or feasibility of the Project's initial 8.8 MW development with two gas modules in-service by late 2014 - at most, the YECL project might affect timing of the Project's third unit if actual peak load requirements on the grid by late 2016 are less than forecast in Appendix C of this Application.

TOPIC:

REFERENCE: Page 23

"... These new generation capacity requirements on the isolated Yukon grid are forecast after full consideration of DSM initiatives by YEC and YECL to reduce ongoing load growth."

PREAMBLE:

QUESTION:

a) Are the DSM initiatives being referred to here the DSM plan filed in conjunction with YECL's recent 2013-2015 RGA [sic]?

b) Please list the specific peak shaving and load shifting initiatives contained in this DSM plan.

c) Has Yukon Energy developed an enhanced DSM plan to focus on peak demand reduction through peak shaving and load shifting as a partial alternative to the project? If so please provide the details of this option, if not please explain why not.

ANSWER:

(a)

Yes.

(b) and **(c)**

As noted in response to YCS-YECL-1-6 in the YECL 2013/15 GRA, all programs included in the DSM Plan have coincidental peak savings, as outlined for each program shown in Exhibit 4 on page 15 and Exhibit 5 on page 16 of the Yukon Five Year Demand Side Management Plan included in the YECL Application. There are no specific programs to address peak shifting included in the DSM plan. Peak shifting programs tend to be costly and complex to administer as they require a high degree of customer

participation and generally require enforceable regulation to ensure the technology is used during those peak times. Under the current rate structure and customer available data, there is no customer incentive to develop programming to address peak shifting. In developing their first DSM programs, the utilities focused on electricity usage savings which is more cost effective and results in coincidental peak savings.

TOPIC:

REFERENCE: Page 23 Section 4.2.2

"No feasible renewable resource alternatives to the Project have been identified within the relevant time frame."

PREAMBLE:

QUESTION:

a) Please provide a table of "base case" load forecasts used in this Application and "base case" forecasts used in the "Overview" (Table A-1 on page A-3), referenced in Footnote 27 on page 23, for each year for a 40 year period starting in 2015.
b) Please explain the differences between these two "base case" forecasts.

ANSWER:

(a)

Please see Table 1 below for the comparison of Base Case load forecast from YEC's 2011-2030 Resource Plan Overview and LNG Part 3 application.

YEC does not have an extended load forecast for 40 years starting from 2015, and such a forecast is not relevant to the economics of the Project. The need for the Project is derived from the capacity requirements as noted in the Application which will involve replacing two diesel generating units scheduled for retirement by 2015 with three new modular natural gas-fired generating units. The cost saving benefits of the Project relative to diesel forecast in the initial years (and to 2030) are sufficient to confirm the Project's feasibility relative to the new diesel alternative.

Table 1.
Comparison of Base Case Load Forecasts

Forecast Years	Base Case Load Forecast (GW.h)		
	Table A-1 of 2011-2030 Resource Plan Overview	Table C-1 of LNG Part 3 Application (no Alexco)	Difference (GW.h)
2013	430.4	413.4	-17.0
2014	443.3	416.0	-27.3
2015	449.1	426.3	-22.8
2016	455.0	437.3	-17.7
2017	454.3	444.3	-10.0
2018	460.5	451.5	-9.0
2019	461.6	458.9	-2.7
2020	440.5	466.4	25.8
2021	408.8	475.3	66.5
2022	415.5	484.4	68.9
2023	422.4	450.4	27.9
2024	429.5	460.0	30.5
2025	436.7	470.0	33.3
2026	444.1	481.3	37.2
2027	451.7	493.0	41.4
2028	459.4	505.1	45.8
2029	467.3	517.6	50.3
2030	475.3	530.4	55.1

(b)

The grid load forecasts are updated on ongoing basis to reflect non-industrial load growth changes, ongoing DSM/SSE related activities as well as expected industrial load changes.

The differences in Base Case load forecasts in Table 1 above in part reflects the base year load:

- Load forecast as provided in Table A-1 of YEC's 2011-2030 Resource Plan Overview was based on original 2012/13 GRA load forecasts for 2012 and 2013 as the base years;

- Load forecast in Appendix C of LNG Part 3 Application is based on YEC's 2014 load forecast as base year.

The differences in the Base Case load forecasts also reflect the following:

Non-industrial load forecast:

- Non-industrial load forecast as provided in Table A-1 YEC's 2011-2030 Resource Plan Overview was based on 2.26%/year growth rate;

- Non-industrial load forecast as provided in Table C-1 of Appendix C of the Application is based on growth at 2.26%/year for 2015, at 2.45%/year for 2016-2020 inclusive, at 2.82%/year for 2021-2025 inclusive, at 3.13%/year for 2026 and thereafter. The growth rates used for year 2016 and beyond are derived from Yukon Electricity Conservation and Demand Management Potential Review (CPR) report prepared by ICF Marbek[1].

DSM/SSE:

- DSM/SSE in Table A-1 YEC's 2011-2030 Resource Plan Overview was based on 50% of the initial DSM/SSE forecast prepared for 2011-2030 Resource Plan update. The initial DSM/SSE forecast was based on 5.4 GW.h/year load reduction starting from 2014 plus the same growth rate as the non-industrial load growths [2.26%].

- DSM/SSE for Appendix C of the Application assumed at 32% of annual load growth based on CPR report; to reflect proposed DSM plans (YECL 2013-15 GRA goal of 8.5 GW.h/year sustained electricity savings by 2018), impact reduced for the first year (2015) taking ¼ of the assumed 32%, 2/3 for 2016, and at full 32% starting from 2017. The impact of DSM/SSE for 2020 is forecast to be about 14.6 GW.h load reduction (compared to 23.4 GW.h in Resource Plan Overview July 2012) and by 2030 is forecast to reach at 59.5 GW.h (compared to 59.2 GW.h in Resource Plan Overview July 2012).

[1] Please see Yukon Five Year Demand Side Management Plan as filed with YECL's 2013-15 GRA.

Industrial load Forecast:

- Base Case industrial load forecast in YEC's 2011-2030 Resource Plan Overview included the following industrial customers:
  - Minto generation load at 46.7 GW.h/yr until 2019, and 23.4 GW.h in 2020 until mid-year (no load thereafter);
  - Alexco generation load at 15.9 GW.h/yr forecast in 2013, 21.7 GW.h/year 2014-16, and 15.0 GW.h/yr assumed 2017-2020 (no load thereafter); and
  - Whitehorse Copper Tailings (WHCT) at 5.2 GW.h/yr in 2013, 9.3 GW.h/yr 2014-2018 and 4.1 GW.h in 2019 (no load thereafter).

- Base Case industrial load forecast in Appendix C of the Application includes the following industrial customers:
  - Minto generation load at 34.6 GW.h/2013, 38.0 GW.h/2014, 40.2 GW.h/2015 and at 43.5 GW.h/year for 2016-2022 (no load thereafter);
  - Alexco generation load at 9 GW.h for 2013 and no load thereafter for No Alexco scenario; and load at 15.2 GW.h for 2015, at 17.4 GW.h for 2016 though 2021 (no load thereafter) for With Alexco scenario.

TOPIC:

REFERENCE: Page 24

"At forecast grid loads in Yukon Energy's 2011 Resource Plan, none of the non-hydro renewable resource options (e.g. wind and biomass were both examined) could provide levelized costs of energy over their life competitive with diesel generation."

PREAMBLE:

QUESTION:

a) Please justify why Yukon Energy's conclusions reached with respect to renewable resource energy supply options analyzed with the significantly lower Overview base case load forecasts starting in 2020 are still applicable to the current application which forecasts significantly higher base case loads from 2020 and continuing indefinitely into the future.

ANSWER:

(a)

The 2011 Resource Plan examined a range of load scenarios, including scenarios with the Victoria Gold mine connected to the grid. Please see response to CW-YEC-1-10 (a, b and d) regarding information that YEC can provide at this time on renewable energy options as summarized in the Application.

TOPIC:

REFERENCE: Page 26 New diesel generator options

PREAMBLE:

QUESTION:

a) Please provide copies of the RFPs, RFEIs, or documentation from an alternate process that Yukon Energy used if not one of these, and all relevant specifications that Yukon Energy used to solicit potential suppliers for:
   i. Non-modular conventional diesel-only generators;
   ii. Modular conventional diesel-only generators;
   iii. Non-modular dual fuel (diesel-gas) generators; and
   iv. Modular dual fuel generators.

b) For each of the above please provide a list of all the suppliers that responded, which was selected in each category, and explain why they were selected.

ANSWER:

(a)

Please see response to YCS-YEC-1-5 with respect to the investigations carried out by YEC leading to selection of the specific engine supplier and engine in the proposed Project, including the assessment of available new engines. YEC is not proposing to proceed with a new diesel option and accordingly no RPF or other similar process was conducted for new diesel generator options. YEC's information in the Application reflects the Warsila dual fuel unit installation option within the WD1 and WD2 service bays that was examined in the preliminary engineering studied for the Project.

The Request for Information (RFI) issued by Yukon Energy in January 2013 is provided as Attachment 1 to YCS-YEC-1-5.

(b)

The list of suppliers is confidential and cannot be provided.

TOPIC:

REFERENCE: Page 26 New higher efficiency diesel engine replacement

PREAMBLE:

QUESTION:

a) Please explain why dual fuel engines rather than ordinary diesel engines would be specified for Mirrlees replacements? What is the estimated cost of the 6.7 megawatt Wartsila duel fuel engines? Are the

b) What cost saving could be achieved for selecting similar capacity diesel only engines?

c) What cost saving could be achieved by selecting diesel only engines approximately the same size as the Mirrlees engines for replacements, e.g. Caterpillar 3616s?

d) Has Yukon Energy developed cost estimates for a diesel replacement alternative consisting of three Caterpillar 3616s with two replacing the Mirrlees units (instead of the much larger Wartsilas that require very significant balance of plant costs) and a third unit to be located in a pre-engineered building that can be expanded in future as needed on the proposed LNG project site, or at the Mayo road substation, or at the Faro diesel plant? If so please provide the capital cost breakdowns in tables similar to Table 3-1. If not please explain why these options have not been examined.

e) Has Yukon Energy developed cost estimates for a diesel replacement alternative consisting of two Caterpillar 3616s replacing the Mirrlees units and using 2 or 3 modular Caterpillar units similar to the one proposed to be installed in Carcross by YECL) on the proposed LNG project site, or at the Mayo road substation, or at the Faro diesel plant? If so please provide the capital cost breakdown in a table similar to Table 3-1. If not please explain why this option has not been examined.

f) Has Yukon Energy developed cost estimates for a diesel replacement alternative as per (e) above and installing an appropriately sized renewable energy project such as wind to reduce the diesel consumption, particularly in winter? If so please provide the capital cost breakdown in a table similar to Table 3-1. If not please explain why this option has not been examined.

g) Has Yukon Energy developed cost estimates for a diesel replacement alternative consisting of two Caterpillar 3616s replacing the Mirrlees units and implementing a more aggressive DSM plan focused on peak shaving and demand reduction to defer or eliminate the need for a third diesel generator (or LNG generator)? If so please provide the capital cost breakdown in a table similar to Table 3-1. If not please explain why this option has not been examined.

h) What is the estimated cost of the 6.7 MW duel fuel Wartsila engine-generator units?

i) Are there any material differences in the efficiencies of the duel fuel 6.7 MW Wartsila units and the natural gas only or diesel only fired engine-generator units?

j) Has Yukon Energy considered a diesel replacement alternative consisting of purchasing dual fuel (natural gas – diesel) units and deferring natural gas substitution until there is greater certainty with respect to natural gas pricing in an LNG exporting environment? If not please explain why this option has not been examined.

ANSWER:

(a) and **(h)**

Dual fuel engines were considered as a transition to LNG while having the inherent alternative fossil fuel backup to diesel capability at a small cost premium to single fuel diesel. In addition, the preliminary engineering carried out for these specific units provided YEC with the best available information for estimates of cost for new diesel units. The estimated cost of the 6.7 MW Wartsila engines is detailed in YEC's response to YUB-YEC-1-14(c).

(b) and **(c)**

The capital cost savings for the engine alone would be similar to the Wartsila dual fuel option, assuming the same MW capacity and same location in the WD1 and WD2 bays after demolition of the existing units. The overall capital cost for a new diesel option would not incur the LNG storage and vaporizing infrastructure cost, and also would not secure the fuel savings that are provided by conversion from diesel to natural gas.

The selection of a specific engine such as the Cat 3616 would not have met the reserve capacity requirement utilizing just the 2 Mirrlees bays. The reserve capacity requirement is 13 MW by 2017. Two Cat 3616's on diesel would be rated not more than 10 MW which would not be sufficient. Two 6.7 MW Wartsila engines would have met this requirement hence were the large engine alternative considered.

(d) and **(e)**

The Cat 3616 engines would not have resulted in any significant decrease in balance of plant costs.

Examining new diesel at a new location was not considered, and therefore a capital cost breakdown table is not available for a third diesel unit located in a modular plant at another location. Although a range of site options were examined for the Project (see YUB-YEC-1-10(c); YUB-YEC-1-37(a), and YCS-YEC-1-40), Yukon Energy has not considered use of a wide range of other diesel only alternatives as there would be no fuel savings under such an approach, and overall there were also benefits to retaining thermal generation at the WTGS. There are always a wide variety of alternatives that can be thought of but there are also limited time and resources to be spent to doing studies.

(f)

The option put forward in YCS/LE-YEC-1-38(e) was not considered. Wind continues to be an option in the future for YEC.

(g)

This option has not been considered. The 5-year DSM plan is currently being considered by the YUB; it would not be prudent to consider a more aggressive plan until the YUB has completed its review of the existing plan.

(i)

There are no material differences in the efficiencies of the dual fuel 6.7 MW Wartsila units and the natural gas only or diesel only fired engine-generator units. Please see also response to YUB-YEC-1-55(b).

(j)

A dual fuel alternative was considered, i.e., the Wartsila 6.7 MW option. YEC does not consider there to be a significant risk related to the price of LNG relative to the price of diesel fuel. Please see Application pages 40-41 and response to YUB-YEC-1-55(a).

TOPIC:

REFERENCE: Page 27

"Opportunities to reduce diesel generations [sic] emissions would be deferred ..."

PREAMBLE:

QUESTION:

a) Is it not true that new diesel generators are both more fuel efficient and produce lower emissions than the existing diesel fleet? If true, please explain what Yukon Energy means by the referenced statement.

ANSWER:

(a)

The Application recognizes that new diesel generators are expected to be more fuel efficient than the existing diesel fleet. However, please note that the above quote was referencing the opportunity to displace diesel generation with a lower cost and lower emission alternative, i.e., natural gas. The full quote at page 27 of the Application, referenced in part above, is as follows:

> *"Opportunities to reduce diesel generation emissions would be deferred, and economic development opportunities that could be realized from the Project related to introducing lower cost natural gas fuel to Yukon would also be deferred."*

Please see response to CW-YEC-1-1(i) Attachment 1 for further detail regarding air quality and in particular Table A-1, which provides Project air emissions (GE 4.375 MW) as compared to alternatives (new and existing diesel engines).

TOPIC:

REFERENCE: Page 27 Footnote 41

PREAMBLE:

QUESTION:

a) Please provide all the detailed cost and other analyses used in Yukon Energy's assessments that arrived at the conclusion that the Mayo Road substation would not be cost effective or practical alternative project location.

ANSWER:

(a)

Yukon Energy provided a detailed explanation regarding the suitability of the Mayo Road substation as an alternative location for the Project in its January 29, 2014 response to YESAB information request R6 which is excerpted below. Please see also YUB-YEC-1-10(c) for more detailed review of all options considered and the rationale for the selection of the current site as the preferred option for development of the Project.

Project Assessment 2013.0115 – Response to 2014.01.21 Information Requests, R6

Describe any considerations including suitability of the Mayo Road Substation as an alternative location for this Project.

Response

As reviewed below, the Project Proposal reviewed the rational for locating the Project at Whitehorse, and within Whitehorse at Yukon Energy's existing Thermal Generating Station (WTGS) site. Although not addressed in the Project Proposal, the Mayo Road Substation site was examined as an alternative and relevant issues related to this alternative are reviewed below.

As stated in Section 1.5 of the Project Proposal, the Project's Purpose is to ensure that Yukon Energy maintains the infrastructure necessary in the next few years to address the YUB's recommended reserve capacity planning criteria requirements, has reserve capacity for seasonal low water periods and drought years, and is able to meet non-industrial load growth and peak demand in the short term with the least impact on ratepayers.

The Project is needed to replace two diesel thermal units located at the WTGS and scheduled for retirement in 2014 and 2015, respectively, in order to achieve the project purpose.

As has been described in the Project Proposal, the Project Purpose and Need are proposed to be met with newer, more efficient natural-gas fired engines and related infrastructure that will result in reduced fuel costs, reduced greenhouse gas and particulate emissions, and increased capacity and reliability. This will also in effect modernize the WTGS and retain flexible and reliable thermal grid generation at Whitehorse.

As stated in the Project Proposal, the existing WTGS operation was determined to be an optimum location for the conversion of diesel units to cleaner burning natural gas fired engines for the following reasons:

- Whitehorse is the nearest practical grid location for LNG deliveries from Alberta or British Columbia.

- Whitehorse is the location of the Yukon grid's largest load center.

- The conversion project offers the opportunity to use new gas fired generation to modernize the Whitehorse plant facilities, with its established infrastructure (including transformer capability and on site staffing needed to operate and maintain the remaining diesel plant, good road access). Existing assets greatly facilitate cost effective development of the Project, concurrent with the retirement of existing diesel capacity at these facilities.

- Major elements of the existing diesel plant at the WTGS will continue to be required over at least the next decade under any scenario examined.

- The option of developing a new “greenfield” site for the Project in the Whitehorse area and separate from the WTGS was considered, but was not found to be cost effective or practical. One site that was assessed, but not selected, was the Takhini Substation [referenced in the request as the "Mayo Road Substation"] located along the North Klondike Highway, approximately 7.5 km north of its intersection with the Alaska Highway.

The following provides a summary of the considerations made in comparing the Takhini Substation as regards this alternative and the preferred Project location at the WTGS site:

- An assessment of the Takhini Substation site indicated a comparatively larger amount of civil construction work that would be required to provide an adequate building surface for the new engine modules, auxiliary system modules, LNG storage, offloading and vaporization systems, access roads and new substation equipment, when compared to the proposed site;

- The Project design relies on and exploits energy efficiency opportunities offered by the presence of established infrastructure at the preferred site, such as a fire suppression system, existing heating loads (i.e., the boiler installed within the Whitehorse Diesel Plant) and associated glycol/hot water piping, and the dike heating system to facilitate the integration of the new infrastructure associated with the diesel-natural gas conversion project and the existing infrastructure. Pursuing the development at the Takhini Substation would forgo the substantive opportunity for efficiencies and cost savings associated with the existing site and would entail starting from scratch as regards the requirement to install the additional equipment to meet the alternative site needs.

- The Takhini Substation alternative would preclude current and future use of waste heat (produced during thermal electricity production) to meet existing or new thermal loads at the Whitehorse Rapids Generating Station. Under the current Project description, the existing boiler system is will use boil off gas associated with LNG storage as a primary source of fuel when the natural gas units are not operating and waste heat off the natural gas units when they are operating. The heat generated from the combustion would then be used to meet existing thermal loads and potentially justify expansion of a “district heat” system to other buildings within the Whitehorse Rapids Generating Station. As stated in the Project Proposal, secondary and tertiary options for boil off gas handling

include flaring and venting, respectively, but the opportunity to utilize boil off gas locally for heating loads during times when the generators are not operating is an important part of the project design to minimize or otherwise eliminate the need for flaring or venting. A development at the Takhini Substation would require a different boil off gas management plan and likely rely more on flaring.

- From an operational standpoint, a site close to existing infrastructure will allow Yukon Energy personnel shorter response times for operational tasks and in the event of a system failure (e.g., to visually inspect and monitor alarms) or to simply proceed with a LNG fuel delivery. This will also remove the need for operations staff to have to travel by vehicle to the Takhini site.

- Communication currently in place between WRGS and Takhini Substation would need to be upgraded over a distance of 25 km to handle the new location of the site for remote control and closed circuit television (CCTV) requirements. This work is also required for the facilities within the expanded site area, but only involves the installation of a few hundred metres of fibre optic cable.

- A development at the WTGS site will facilitate potential future conversion of existing diesel engines (four EMD units and one Caterpillar unit) to bi-fuel (diesel and natural gas). Fuel blending could prove beneficial in reducing operating costs of remaining diesel engines. Such conversion could not occur if the new infrastructure was to be built at the Takhini Substation (i.e., new LNG infrastructure would be required at the WTGS). The distance between the natural gas storage tanks and generating units would be too great and require material financial resources to build the required gas distribution infrastructure. The preferred site also retains the option in the future to replace some or all of the remaining engines with new natural gas engines should the expanded site area reach its maximum development potential.

- A greenfield development at Takhini Substation would preclude the potential opportunity to support the City of Whitehorse, Kwanlin Dün First Nation, or others with any gas and/or waste heat that they may look to use in developing their respective lands adjacent the proposed project site in the future. The City of Whitehorse is currently investigating building its municipal services building on a nearby parcel. LNG storage in the vicinity of these potential future development sites could facilitate the use of natural gas or waste heat from electricity

generation to meet heating loads. The Takhini site is located in an area with sparse development and the nearby heating loads are mostly single family homes on acreages separated by relatively long distances. The heat load demand and distances from the heat source severely limit the feasibility of such an opportunity at the Takhini location.

TOPIC:

REFERENCE: Page 29

"... The annual fuel costs estimates in Table 4-3 also assume operation of these new units to enhance hydro storage for use in wintertime..." and

Page 30

"Operation of the new gas-fired generation capacity can be used, however, to assist in storing water at Aishihik and (to a much lesser extent) at Mayo during the summer... thereby allowing added hydro generation capability to be utilized in peak winter months..."

PREAMBLE:

QUESTION:

a) For each of the months of June, July, August, and September please provide, in table format, the following actual 2013 data (with Alexco) and the projected 2014 data (without Alexco and with Fish Lake #1), and the projected 2016 data (base case):
    i. The available Whitehorse Rapids and Mayo hydro capacities, in MW, that must either be used or spilled;
    ii. The monthly average load in MW;
    iii. The average daytime peak load in MW; and
    iv. The average minimum night time load in MW.

b) If gas fired generators can usefully generate power in the summer that results directly in water storage in Aishihik Lake (or Mayo Lake) for winter usage, would other forms of renewable energy generation available in summer (e.g. solar PV or wind) not also result in stored water that can be used in winter?

ANSWER:

(a)

Please see Table 1 below.

Please note that YEC does not forecast daytime/nighttime peak. Water spillage would be based on energy demand, capacity as well as water storage license restrictions.

Table 1:
Installed capacity for Whitehorse Rapids and Mayo Hydro Generation Stations, and Monthly Average Load Data for YEC

		2013		
		July	**August**	**September**
Installed Capacity				
Whitehorse Rapid GS	MW	40	40	40
Mayo GS	MW	5.4	5.4	5.4
2013 Actual				
Monthly Average Load	MW	43.1	37.1	41.3
The average daytime peak load	MW	42	43.5	42.7
The average night time peak load	MW	39.1	40.4	40.2
Monthly Average Load				
2014, Base Case no Alexco	MW	37.5	38.7	43.9
2016, Base Case no Alexco	MW	39.2	40.6	45.9

Notes:
1. Daytime for average peak is assumed between 7 am and 7 pm.
2. Average peak numbers do not include internal loads and line losses.

(b)

Other renewable generation sources also provide some water storage in summer months, which then may be used for winter load supply. For example, as provided in Figure 5-3 in Overview of YEC's 20 Year Resource Plan: 2011-2030, with 21 MW Ferry Hill wind project the stored water in summer could displace up to 14.6 GW.h diesel

generation in winter at 545 GW.h[1] load level. This ability to provide stored water was included in the Overview assessment of other renewable resource options such as wind.

[1] Scenario A load level for 2015 examined in 2011-2030 Resource Plan with Victoria Gold mine.

TOPIC:

REFERENCE: Page 32 Table 4-3

PREAMBLE:

QUESTION:

a) Please provide the Excel spreadsheets, with the formulae intact, from which the figures in Table 4-3 are derived.

b) To more fully understand the fuel price risk please provide new versions of Table 4-3 which incorporate the following assumptions:
   i. The diesel alternative capital cost $5 million lower, i.e. $28.6 million;
   ii. The diesel alternative capital cost $10 million lower, i.e. $23.6 million;
   iii. The natural gas purchase costs for each of $5.50, $6.50, $7.50, and $8.50 per MMBtu;
   iv. Separately number (i) and (ii) above repeated with each of the prices in (iii).

ANSWER:

(a)

Please see UCG-YEC-1-2 Attachment 1 for the excel version of Figure 3-1 and supporting calculations in Table 4-3.

(b)

Please see YCS/LE-1-14(b) and (c).

Please see Attachment 1 to this response for the analysis with different LNG fuel costs and lower diesel alternative capital costs as requested.

Table 1.1: Ratepayer Impacts from Whitehorse Diesel-Natural Gas Conversion Project ($million) (Project compared to New Diesel Alternative with $5 million lower cost)

Gas at $5.5/MMBTu, efficiency 40%, A-Train from Calgary

14.35 cents/kW.h

		2014	2015	2016	2017	2018
Capital cost ($million) at yr end						
Total	Diesel (new)	19.19	9.45			
	LNG	34.36		4.4		
Net	Diesel (new)	19.19	28.2	27.5	26.8	26.2
	LNG	34.36	33.5	37.1	36.2	35.2
Annual Capital Cost ($million)						
Deprec	Diesel (new)		0.444	0.680	0.680	0.680
	LNG		0.823	0.823	0.933	0.933
Return	Diesel (new)		1.292	1.518	1.481	1.444
	LNG		1.850	1.925	1.997	1.946
Total	Diesel (new)		1.735	2.198	2.161	2.124
	LNG		2.673	2.748	2.930	2.879
Difference (LNG-Diesel)			**0.938**	**0.550**	**0.769**	**0.755**
Annual Fuel Cost ($million)						
Forecast Diesel (GWh)			17	22.9	26.9	31.4
% New	Diesel (new)		90%	100%	100%	100%
	LNG		100%	95%	100%	100%
Fuel Cost	Diesel (new)		4.252	5.633	6.617	7.724
	LNG		2.440	3.450	3.860	4.506
Difference (LNG-Diesel)			**-1.812**	**-2.183**	**-2.757**	**-3.219**
Net Ratepayer Impact ($million)						
	Diesel (new)		5.987	7.832	8.779	9.849
	LNG		5.112	6.198	6.790	7.385
Difference (LNG-Diesel)			**-0.874**	**-1.633**	**-1.988**	**-2.464**

Notes:

1. All capital costs depreciated over 40 years; return on mid-year rate base at 5.45%/year.
2. Diesel fuel costs at 24.6 c/kWh new diesel, 28.7 c/kWh other diesel.
3. New Diesel capital cost is lower than cost shown in Table 4-3 of Part 3 application by $5 million.

Table 1.2: Ratepayer Impacts from Whitehorse Diesel-Natural Gas Conversion Project ($million) (Project compared to New Diesel Alternative with $5 million lower cost)

Gas at $6.5/MMBTu, efficiency 40%, A-Train from Calgary

15.20 cents/kW.h

		2014	2015	2016	2017	2018
Capital cost ($million) at yr end						
Total	Diesel (new)	19.19	9.45			
	LNG	34.36		4.4		
Net	Diesel (new)	19.19	28.2	27.5	26.8	26.2
	LNG	34.36	33.5	37.1	36.2	35.2
Annual Capital Cost ($million)						
Deprec	Diesel (new)		0.444	0.680	0.680	0.680
	LNG		0.823	0.823	0.933	0.933
Return	Diesel (new)		1.292	1.518	1.481	1.444
	LNG		1.850	1.925	1.997	1.946
Total	Diesel (new)		1.735	2.198	2.161	2.124
	LNG		2.673	2.748	2.930	2.879
Difference (LNG-Diesel)			**0.938**	**0.550**	**0.769**	**0.755**
Annual Fuel Cost ($million)						
Forecast Diesel (GWh)			17	22.9	26.9	31.4
% New	Diesel (new)		90%	100%	100%	100%
	LNG		100%	95%	100%	100%
Fuel Cost	Diesel (new)		4.252	5.633	6.617	7.724
	LNG		2.584	3.635	4.089	4.773
Difference (LNG-Diesel)			**-1.668**	**-1.998**	**-2.529**	**-2.952**
Net Ratepayer Impact ($million)						
	Diesel (new)		5.987	7.832	8.779	9.849
	LNG		5.257	6.383	7.019	7.652
Difference (LNG-Diesel)			**-0.730**	**-1.448**	**-1.760**	**-2.197**

Notes:

1. All capital costs depreciated over 40 years; return on mid-year rate base at 5.45%/year.
2. Diesel fuel costs at 24.6 c/kWh new diesel, 28.7 c/kWh other diesel.
3. New Diesel capital cost is lower than cost shown in Table 4-3 of Part 3 application by $5 million.

Table 1.3: Ratepayer Impacts from Whitehorse Diesel-Natural Gas Conversion Project ($million) (Project compared to New Diesel Alternative with $5 million lower cost)

Gas at $7.5/MMBTu, efficiency 40%, A-Train from Calgary

16.05 cents/kW.h

		2014	2015	2016	2017	2018
Capital cost ($million) at yr end						
Total	Diesel (new)	19.19	9.45			
	LNG	34.36		4.4		
Net	Diesel (new)	19.19	28.2	27.5	26.8	26.2
	LNG	34.36	33.5	37.1	36.2	35.2
Annual Capital Cost ($million)						
Deprec	Diesel (new)		0.444	0.680	0.680	0.680
	LNG		0.823	0.823	0.933	0.933
Return	Diesel (new)		1.292	1.518	1.481	1.444
	LNG		1.850	1.925	1.997	1.946
Total	Diesel (new)		1.735	2.198	2.161	2.124
	LNG		2.673	2.748	2.930	2.879
Difference (LNG-Diesel)			**0.938**	**0.550**	**0.769**	**0.755**
Annual Fuel Cost ($million)						
Forecast Diesel (GWh)			17	22.9	26.9	31.4
% New	Diesel (new)		90%	100%	100%	100%
	LNG		100%	95%	100%	100%
Fuel Cost	Diesel (new)		4.252	5.633	6.617	7.724
	LNG		2.729	3.820	4.317	5.040
Difference (LNG-Diesel)			**-1.523**	**-1.813**	**-2.300**	**-2.685**
Net Ratepayer Impact ($million)						
	Diesel (new)		5.987	7.832	8.779	9.849
	LNG		5.401	6.568	7.248	7.919
Difference (LNG-Diesel)			**-0.585**	**-1.263**	**-1.531**	**-1.930**

Notes:

1. All capital costs depreciated over 40 years; return on mid-year rate base at 5.45%/year.
2. Diesel fuel costs at 24.6 c/kWh new diesel, 28.7 c/kWh other diesel.
3. New Diesel capital cost is lower than cost shown in Table 4-3 of Part 3 application by $5 million.

Table 1.4: Ratepayer Impacts from Whitehorse Diesel-Natural Gas Conversion Project ($million) (Project compared to New Diesel Alternative with $5 million lower cost)

Gas at $8.5/MMBTu, efficiency 40%, A-Train from Calgary

16.91 cents/kW.h

		2014	2015	2016	2017	2018
Capital cost ($million) at yr end						
Total	Diesel (new)	19.19	9.45			
	LNG	34.36		4.4		
Net	Diesel (new)	19.19	28.2	27.5	26.8	26.2
	LNG	34.36	33.5	37.1	36.2	35.2
Annual Capital Cost ($million)						
Deprec	Diesel (new)		0.444	0.680	0.680	0.680
	LNG		0.823	0.823	0.933	0.933
Return	Diesel (new)		1.292	1.518	1.481	1.444
	LNG		1.850	1.925	1.997	1.946
Total	Diesel (new)		1.735	2.198	2.161	2.124
	LNG		2.673	2.748	2.930	2.879
Difference (LNG-Diesel)			**0.938**	**0.550**	**0.769**	**0.755**
Annual Fuel Cost ($million)						
Forecast Diesel (GWh)			17	22.9	26.9	31.4
% New	Diesel (new)		90%	100%	100%	100%
	LNG		100%	95%	100%	100%
Fuel Cost	Diesel (new)		4.252	5.633	6.617	7.724
	LNG		2.875	4.007	4.549	5.310
Difference (LNG-Diesel)			**-1.377**	**-1.626**	**-2.069**	**-2.415**
Net Ratepayer Impact ($million)						
	Diesel (new)		5.987	7.832	8.779	9.849
	LNG		5.548	6.755	7.479	8.189
Difference (LNG-Diesel)			**-0.439**	**-1.076**	**-1.300**	**-1.660**

Notes:

1. All capital costs depreciated over 40 years; return on mid-year rate base at 5.45%/year.
2. Diesel fuel costs at 24.6 c/kWh new diesel, 28.7 c/kWh other diesel.
3. New Diesel capital cost is lower than cost shown in Table 4-3 of Part 3 application by $5 million.

Table 2.1: Ratepayer Impacts from Whitehorse Diesel-Natural Gas Conversion Project ($million) (Project compared to New Diesel Alternative with $10 million lower cost)

Gas at $5.5/MMBTu, efficiency 40%, A-Train from Calgary
14.35 cents/kW.h

		2014	2015	2016	2017	2018
Capital cost ($million) at yr end						
Total	Diesel (new)	15.84	7.80			
	LNG	34.36		4.4		
Net	Diesel (new)	15.84	23.3	22.7	22.2	21.6
	LNG	34.36	33.5	37.1	36.2	35.2
Annual Capital Cost ($million)						
Deprec	Diesel (new)		0.360	0.555	0.555	0.555
	LNG		0.823	0.823	0.933	0.933
Return	Diesel (new)		1.066	1.254	1.224	1.193
	LNG		1.850	1.925	1.997	1.946
Total	Diesel (new)		1.426	1.809	1.779	1.748
	LNG		2.673	2.748	2.930	2.879
Difference (LNG-Diesel)			**1.247**	**0.939**	**1.151**	**1.131**
Annual Fuel Cost ($million)						
Forecast Diesel (GWh)			17	22.9	26.9	31.4
% New	Diesel (new)		90%	100%	100%	100%
	LNG		100%	95%	100%	100%
Fuel Cost	Diesel (new)		4.252	5.633	6.617	7.724
	LNG		2.440	3.450	3.860	4.506
Difference (LNG-Diesel)			**-1.812**	**-2.183**	**-2.757**	**-3.219**
Net Ratepayer Impact ($million)						
	Diesel (new)		5.678	7.442	8.396	9.473
	LNG		5.112	6.198	6.790	7.385
Difference (LNG-Diesel)			**-0.565**	**-1.244**	**-1.606**	**-2.088**

Notes:

1. All capital costs depreciated over 40 years; return on mid-year rate base at 5.45%/year.
2. Diesel fuel costs at 24.6 c/kWh new diesel, 28.7 c/kWh other diesel.
3. New Diesel capital cost is lower than cost shown in Table 4-3 of Part 3 application by $10 million.

Table 2.2: Ratepayer Impacts from Whitehorse Diesel-Natural Gas Conversion Project ($million) (Project compared to New Diesel Alternative with $10 million lower cost)

Gas at $6.5/MMBTu, efficiency 40%, A-Train from Calgary
15.20 cents/kW.h

		2014	2015	2016	2017	2018
Capital cost ($million) at yr end						
Total	Diesel (new)	15.84	7.80			
	LNG	34.36		4.4		
Net	Diesel (new)	15.84	23.3	22.7	22.2	21.6
	LNG	34.36	33.5	37.1	36.2	35.2
Annual Capital Cost ($million)						
Deprec	Diesel (new)		0.360	0.555	0.555	0.555
	LNG		0.823	0.823	0.933	0.933
Return	Diesel (new)		1.066	1.254	1.224	1.193
	LNG		1.850	1.925	1.997	1.946
Total	Diesel (new)		1.426	1.809	1.779	1.748
	LNG		2.673	2.748	2.930	2.879
Difference (LNG-Diesel)			**1.247**	**0.939**	**1.151**	**1.131**
Annual Fuel Cost ($million)						
Forecast Diesel (GWh)			17	22.9	26.9	31.4
% New	Diesel (new)		90%	100%	100%	100%
	LNG		100%	95%	100%	100%
Fuel Cost	Diesel (new)		4.252	5.633	6.617	7.724
	LNG		2.584	3.635	4.089	4.773
Difference (LNG-Diesel)			**-1.668**	**-1.998**	**-2.529**	**-2.952**
Net Ratepayer Impact ($million)						
	Diesel (new)		5.678	7.442	8.396	9.473
	LNG		5.257	6.383	7.019	7.652
Difference (LNG-Diesel)			**-0.421**	**-1.059**	**-1.377**	**-1.821**

Notes:

1. All capital costs depreciated over 40 years; return on mid-year rate base at 5.45%/year.
2. Diesel fuel costs at 24.6 c/kWh new diesel, 28.7 c/kWh other diesel.
3. New Diesel capital cost is lower than cost shown in Table 4-3 of Part 3 application by $10 million.

Table 2.3: Ratepayer Impacts from Whitehorse Diesel-Natural Gas Conversion Project ($million) (Project compared to New Diesel Alternative with $10 million lower cost)

Gas at $7.5/MMBTu, efficiency 40%, A-Train from Calgary
16.05 cents/kW.h

		2014	2015	2016	2017	2018
Capital cost ($million) at yr end						
Total	Diesel (new)	15.84	7.80			
	LNG	34.36		4.4		
Net	Diesel (new)	15.84	23.3	22.7	22.2	21.6
	LNG	34.36	33.5	37.1	36.2	35.2
Annual Capital Cost ($million)						
Deprec	Diesel (new)		0.360	0.555	0.555	0.555
	LNG		0.823	0.823	0.933	0.933
Return	Diesel (new)		1.066	1.254	1.224	1.193
	LNG		1.850	1.925	1.997	1.946
Total	Diesel (new)		1.426	1.809	1.779	1.748
	LNG		2.673	2.748	2.930	2.879
Difference (LNG-Diesel)			**1.247**	**0.939**	**1.151**	**1.131**
Annual Fuel Cost ($million)						
Forecast Diesel (GWh)			17	22.9	26.9	31.4
% New	Diesel (new)		90%	100%	100%	100%
	LNG		100%	95%	100%	100%
Fuel Cost	Diesel (new)		4.252	5.633	6.617	7.724
	LNG		2.729	3.820	4.317	5.040
Difference (LNG-Diesel)			**-1.523**	**-1.813**	**-2.300**	**-2.685**
Net Ratepayer Impact ($million)						
	Diesel (new)		5.678	7.442	8.396	9.473
	LNG		5.401	6.568	7.248	7.919
Difference (LNG-Diesel)			**-0.276**	**-0.874**	**-1.148**	**-1.554**

Notes:

1. All capital costs depreciated over 40 years; return on mid-year rate base at 5.45%/year.
2. Diesel fuel costs at 24.6 c/kWh new diesel, 28.7 c/kWh other diesel.
3. New Diesel capital cost is lower than cost shown in Table 4-3 of Part 3 application by $10 million.

Table 2.4: Ratepayer Impacts from Whitehorse Diesel-Natural Gas Conversion Project ($million) (Project compared to New Diesel Alternative with $10 million lower cost)

Gas at $8.5/MMBTu, efficiency 40%, A-Train from Calgary
16.91 cents/kW.h

		2014	2015	2016	2017	2018
Capital cost ($million) at yr end						
Total	Diesel (new)	15.84	7.80			
	LNG	34.36		4.4		
Net	Diesel (new)	15.84	23.3	22.7	22.2	21.6
	LNG	34.36	33.5	37.1	36.2	35.2
Annual Capital Cost ($million)						
Deprec	Diesel (new)		0.360	0.555	0.555	0.555
	LNG		0.823	0.823	0.933	0.933
Return	Diesel (new)		1.066	1.254	1.224	1.193
	LNG		1.850	1.925	1.997	1.946
Total	Diesel (new)		1.426	1.809	1.779	1.748
	LNG		2.673	2.748	2.930	2.879
Difference (LNG-Diesel)			**1.247**	**0.939**	**1.151**	**1.131**
Annual Fuel Cost ($million)						
Forecast Diesel (GWh)			17	22.9	26.9	31.4
% New	Diesel (new)		90%	100%	100%	100%
	LNG		100%	95%	100%	100%
Fuel Cost	Diesel (new)		4.252	5.633	6.617	7.724
	LNG		2.875	4.007	4.549	5.310
Difference (LNG-Diesel)			**-1.377**	**-1.626**	**-2.069**	**-2.415**
Net Ratepayer Impact ($million)						
	Diesel (new)		5.678	7.442	8.396	9.473
	LNG		5.548	6.755	7.479	8.189
Difference (LNG-Diesel)			**-0.130**	**-0.687**	**-0.917**	**-1.284**

Notes:

1. All capital costs depreciated over 40 years; return on mid-year rate base at 5.45%/year.
2. Diesel fuel costs at 24.6 c/kWh new diesel, 28.7 c/kWh other diesel.
3. New Diesel capital cost is lower than cost shown in Table 4-3 of Part 3 application by $10 million.

TOPIC:

REFERENCE: Page 35 Table 4-5

PREAMBLE:

QUESTION:

a) To more fully understand the fuel price risk please provide and expanded Table 4-5 to include gas purchase costs of $5.50, $6.50, $7.50, and $8.50 per MMBtu.

ANSWER:

(a)

Please see Table 1 below for the requested information. Please also note response to YUB-YEC-1-44 for updated LNG haul cost estimates.

Table 1:
Expanded Range of LNG Fuel Cost Savings

LNG Fuel Cost Saving ($/kW.h)			
New Diesel	LNG		LNG Saving
		A-Train from Calgary with 18% premium	
0.246	0.115	gas at $3.5/MMBTu, efficiency 44%	0.131
0.200	0.115	gas at $3.5/MMBTu, efficiency 44%	0.085
0.246	0.135	gas at $4.5/MMBTu, efficiency 40%	0.111
0.200	0.135	gas at $4.5/MMBTu, efficiency 40%	0.065
0.246	0.143	gas at $5.5/MMBTu, efficiency 40%	0.103
0.246	0.152	gas at $6.5/MMBTu, efficiency 40%	0.094
0.246	0.161	gas at $7.5/MMBTu, efficiency 40%	0.085
0.246	0.169	gas at $8.5/MMBTu, efficiency 40%	0.077
		Tridem from Calgary with 10% premium	
0.246	0.133	gas at $3.5/MMBTu, efficiency 44%	0.113
0.200	0.133	gas at $3.5/MMBTu, efficiency 44%	0.067
0.246	0.154	gas at $4.5/MMBTu, efficiency 40%	0.092
0.200	0.154	gas at $4.5/MMBTu, efficiency 40%	0.046
0.246	0.163	gas at $5.5/MMBTu, efficiency 40%	0.083
0.246	0.171	gas at $6.5/MMBTu, efficiency 40%	0.075
0.246	0.180	gas at $7.5/MMBTu, efficiency 40%	0.066
0.246	0.189	gas at $8.5/MMBTu, efficiency 40%	0.057

TOPIC:

REFERENCE: Page 36 Table 4-6

PREAMBLE:

QUESTION:

a) Please provide an expanded Table 4-6 with diesel capital cost options that are $5 million and $ 10 million lower that provided for, and with gas prices that range up to $8.50 per MMBtu (in $1.00 per MMBtu increments).

ANSWER:

(a)

Please see response to YCS/LE-YEC-1-42 for the annual ratepayer impact analysis with lower New Diesel capital cost and higher LNG fuel costs with $1/MMBtu increments.

TOPIC:

REFERENCE: Page 37 LNG fuel price risk

PREAMBLE:

QUESTION:

a) Please provide the annual average AECO natural gas prices for each of the last 20 years.

b) Please provide the monthly average AECO Natural gas prices for the last 10 years.

c) Please provide Australia's annual average natural gas price for the last 20 years (convert to Canadian dollars).

d) Please provide Australia's monthly average natural gas prices for the last 10 years (convert to Canadian dollars).

e) Does Yukon Energy believe that Canadian natural gas prices will increase as natural gas liquefaction plants and exports are developed as they have done in Australia? If not please provide Yukon Energy's reasoning as to why not.

ANSWER:

(a) and **(b)**

Please see Table 1 below for the AECO natural gas prices from January 2001 to February 2014.

Table 1:
AECO Natural Gas Prices

Month	AECO PRICE (C$/GJ)													
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Jan	$13.8	$3.5	$6.0	$6.6	$6.7	$12.0	$6.9	$6.2	$6.3	$5.2	$3.7	$2.9	$3.0	$3.8
Feb	$9.6	$2.8	$6.7	$6.7	$6.2	$8.5	$6.7	$6.9	$4.7	$5.2	$3.7	$2.5	$2.9	$5.5
Mar	$7.3	$3.1	$8.5	$5.9	$6.3	$7.0	$7.5	$7.4	$4.6	$4.9	$3.4	$2.1	$2.9	
Apr	$7.7	$4.5	$7.2	$6.0	$7.1	$6.3	$7.1	$8.2	$4.0	$3.9	$3.4	$1.8	$3.3	
May	$6.8	$4.4	$6.5	$6.3	$7.4	$6.4	$7.2	$8.9	$3.3	$3.6	$3.5	$1.6	$3.5	
Jun	$5.3	$3.7	$6.6	$7.1	$6.7	$5.4	$7.0	$9.6	$3.6	$3.6	$4.0	$2.0	$3.4	
Jul	$4.4	$3.3	$6.5	$6.8	$7.2	$5.6	$6.2	$10.8	$3.2	$4.0	$3.8	$1.9	$3.1	
Aug	$3.6	$2.6	$5.6	$6.5	$7.3	$5.5	$5.2	$9.1	$3.0	$3.5	$3.5	$2.3	$2.6	
Sep	$3.1	$3.3	$5.8	$6.0	$8.9	$6.2	$5.0	$7.1	$2.7	$3.2	$3.4	$2.1	$2.4	
Oct	$2.1	$4.3	$5.5	$5.4	$10.9	$4.5	$5.0	$6.1	$3.1	$3.4	$3.5	$2.3	$2.7	
Nov	$3.9	$5.3	$5.6	$7.5	$12.5	$6.4	$5.5	$6.6	$4.7	$3.2	$3.2	$3.1	$3.3	
Dec	$3.4	$5.3	$5.3	$7.5	$10.4	$7.6	$6.3	$6.0	$4.6	$3.6	$3.3	$3.3	$3.5	
Annual Average	$5.9	$3.8	$6.3	$6.5	$8.1	$6.8	$6.3	$7.7	$4.0	$3.9	$3.5	$2.3	$3.0	

Sources:

1. January 2001 through July 2013 from Natural Resources Canada
   https://www.nrcan.gc.ca/energy/natural-gas/monthly-market-update/5643
   http://www.nrcan.gc.ca/energy/natural-gas/monthly-market-update/5677
2. August 2013 through February 2014 from Natural Gas Exchange Inc (NGX) at http://www.ngx.com for Alberta Market Price. February 2014 price represents not a full month price as of February 21, 2014.
3. Natural Resources Canada uses a standard conversion factor of 1.055 GJ/MMBtu.

(c) and **(d)**

Please see Table 2 below for the available natural gas prices for Australia from September 2010 to January 2014. YEC do not have Australia natural gas price information for last 10 or 20 years.

Table 2:
Australia Natural Gas Short Term Trading Market Prices

Month	Short Term Trading Market Price (C$/GJ)				
	2010	2011	2012	2013	2014
Jan		$2.03	$2.91	$4.56	$3.86
Feb		$2.81	$3.87	$4.93	
Mar		$2.99	$3.31	$5.01	
Apr		$3.57	$3.31	$5.00	
May		$3.83	$3.92	$5.11	
Jun		$3.71	$5.83	$5.68	
Jul		$3.35	$7.69	$4.83	
Aug		$2.95	$8.57	$4.05	
Sep	$3.26	$3.02	$5.50	$3.26	
Oct	$2.35	$2.76	$5.26	$3.69	
Nov	$1.44	$2.31	$4.56	$3.81	
Dec	$0.98	$2.09	$4.40	$3.61	
Annual Average	**$2.01**	**$2.95**	**$4.93**	**$4.46**	**$3.86**

Sources:

1. Australia Energy Market Operator (AEMO). Ex Post price for Sydney. http://www.aemo.com.au/Gas/Market-Data/Short-Term-Trading-Market-Data
2. AEMO notes that the STTM price represents a delivered price of gas to the Hub. That is, it includes both the commodity and the cost of transportation to the hub.
3. The prices were converted to Canadian dollar by using monthly average exchange rates from Bank of Canada.

(e)

Please see response to UCG-YEC-1-13(c).

TOPIC:

REFERENCE: Page 37-38 LNG Fuel Costs Savings Sensitivity

PREAMBLE:

QUESTION:

a) Please provide the volumes of annual LNG consumptions required to overcome the 18% and 10% premiums in the early years for the A-Trains and Tridem trucks respectively.

b) At what level of grid load would this premium disappear? In what year does Yukon Energy forecast this grid load will occur?

c) Is this premium not a disincentive for Yukon Energy to displace LNG generation with renewable energy?

d) Is this premium stipulated in contracts or proposed contracts for trucking? If so please provide copies of these contracts.

ANSWER:

(a) and **(b)**

LNG consumption will vary depending on grid thermal generation requirements, and these can vary greatly by year and season. The variability is one of the LNG supply chain challenges.

The premium is a conservative estimate included in the economic analysis to account for potential inefficiencies in early year operations due to lower load requirements. The level of premium will depend on LNG trips required and the impact on fixed costs per unit of LNG, and potential arrangements for shared use of the tankers with other LNG loads. YEC at this time has not tried to determine how this may be affected by specific volumes or time periods.

Please see response to YUB-YEC-1-5(e) and YUB-YEC-1-44 for update on haul costs.

(c)

It is unclear how a premium, that raises the cost for LNG, does anything to discourage use of a renewable alternative.

The premium is not a disincentive for YEC to proceed with LNG generation. As noted, the Project remains economic with the premium applied. YUB-YEC-1-5(d) reviews options Yukon Energy is reviewing to coordinate shipping with third parties in the near term in order to increase efficiency of operations.

As noted, Yukon Energy is at this time also pursuing two near term renewable hydro enhancement projects (Marsh Lake and Mayo Lake) and is continuing to investigate greenfield supply options to be advanced over the longer term as larger and more stable loads develop on the Yukon grid.

(d)

The premium is a conservative estimate included in the economic analysis to account for potential inefficiencies in early year operations due to lower load requirements. No transportation agreements are currently in place. It is not contemplated that any "premium" would specifically be included in proposed contracts for trucking; however, Yukon Energy is continuing to look for ways to mitigate potential inefficiencies (and cost penalties) in early year operations (as detailed in response to YUB-YEC-1-5(d)).

TOPIC:

REFERENCE: Page 41 Figure 4-2 and "These forecasts"

PREAMBLE:

QUESTION:

a) For the purposes of Figure 4-2 what assumptions did the U.S. Energy Information Administration ("EIA") make about the rate of substitution of natural gas fired generation for coal fired generation in the U.S.?

b) For the purposes of Figure 4-2 what assumptions did the EIA make about the rate of substitution of natural gas as a transportation fuel for oil as a transportation fuel in the U.S.?

c) For the purposes of Figure 4-2, what level of LNG exports from the U.S. did the EIA assume?

d) Are the U.S. and Canada an integrated natural gas market?

e) For the purposes of Figure 4-2, what level of LNG exports from Canada did the EIA assume?

f) For the purposes of Figure 4-2, what level of decline rates in shale well production did the EIA assume?

g) For the purposes of Figure 4-2, what level of investment in shale well production in the U.S. did the EIA assume?

h) For the purposes of Figure 4-2, what level of return on investment in shale well production did the EIA assume?

i) Is it true that major natural gas producers in the U.S. such as Devon Energy, EOG Resources, Chesapeake Energy and Encana are diverting there financial resources away from drilling dry shale gas to wet shale gas and oil production?

j) If financial resources are diverted away from drilling dry shale gas will there be a tightening of the overall natural gas supply in North America.

k) Given that Yukon Energy has identified natural gas as a substitute for oil meaning diesel, would Yukon Energy expect others to do the same thing?

l) What impact does Yukon Energy think this winter's run up in Henry Hub natural gas prices to a peak of about to $5.60 per MMBtu have on medium to long term natural gas prices in North America?

m) What is meant by "*These forecasts*"? Please provide "*These forecasts*".

ANSWER:

(a)

With regard to the substitution of natural gas fired generation for coal fired generation in the U.S., the U.S. Energy Information Administration in its AEO2013 notes the following:

> "In the AEO2013 Reference case, the competition between coal and natural gas in electricity generation is expected to continue in the near term, particularly in certain regions. However, because natural gas prices are projected to increase more rapidly than coal prices, existing coal plants gradually recapture some of the market lost in recent years. Natural gas-fired plants continue to be the favored source for new generating capacity over much of the projection period because of their relatively low costs and high efficiencies."

AEO2013 also notes that new requirements to control emissions of mercury and acid gases result in the near-term decline in coal demand.

(b)

Please see response to UCG-1-13 (d).

(c)

Regarding the natural gas exports from the U.S., AEO2013 notes the following:

> "U.S. dry natural gas production increases 1.3 percent per year throughout the Reference case projection, outpacing domestic consumption by 2019 and spurring net exports of natural gas (Figure 2). Higher volumes of shale gas production are central to higher total production volumes and a transition to net exports. As domestic supply has increased in recent years, natural gas prices have declined, making the United States a less attractive market for imported natural gas and more attractive for export.
>
> U.S. net exports of natural gas grow to 3.6 trillion cubic feet in 2040 in the Reference case. Most of the projected growth in U.S. exports consists of pipeline exports to Mexico, which increase steadily as growing volumes of imported natural gas from the United States fill the widening gap between Mexico's production and consumption. Declining natural gas imports from Canada also contribute to the growth in U.S. net exports. Net U.S. imports of natural gas from Canada decline sharply from 2016 to 2022, then stabilize somewhat before dropping off again in the final years of the projection, as continued growth in domestic production mitigates the need for imports."

(d)

It is understood that natural gas prices change in response to supply and demand conditions in North America.

Canada National Energy Board notes that natural gas markets in Canada and the United States operate as single integrated market[1] and events relating to weather, storage, transportation or infrastructure, however, have a direct impact on markets in many regions of North America.

(e)

Please see response to UCG-1-13 (a) and (b).

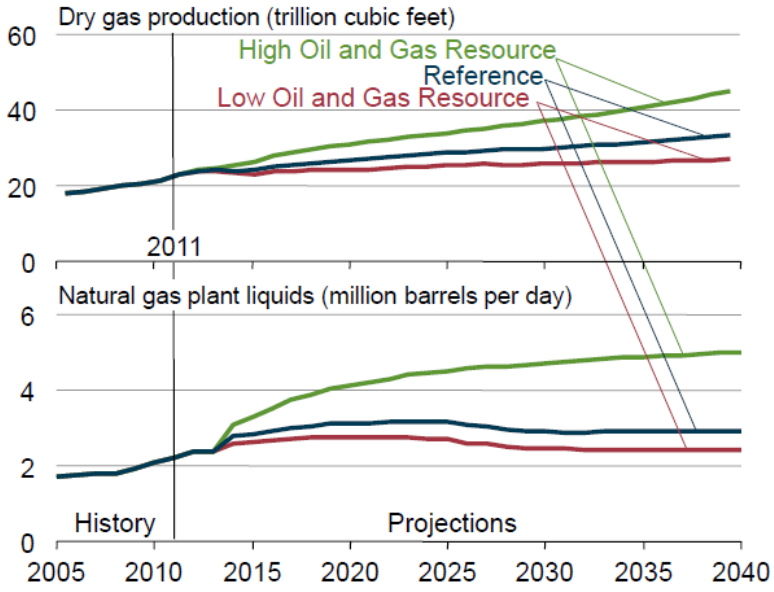
[1] http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/prcng/ntrlgs/cndnmrk-eng.html

(f), (i) and **(j)**

YEC can note what was in the referenced report, but cannot comment on the other questions. Regarding the shale well production, AEO2013 notes the following:

> "Production of NGPL [Natural gas plant liquids], which are extracted from wet natural gas by gas processors, rises more steeply than natural gas production in the first half of the projection period as a result of increased natural gas and oil production from shale wells, which have relatively high liquids contents. As shale gas plays mature, NGPL production levels off or declines even as dry natural gas production increases (Figure 42)."

Figure 42. U.S. production of dry natural gas and natural gas plant liquids in three cases, 2005-2040



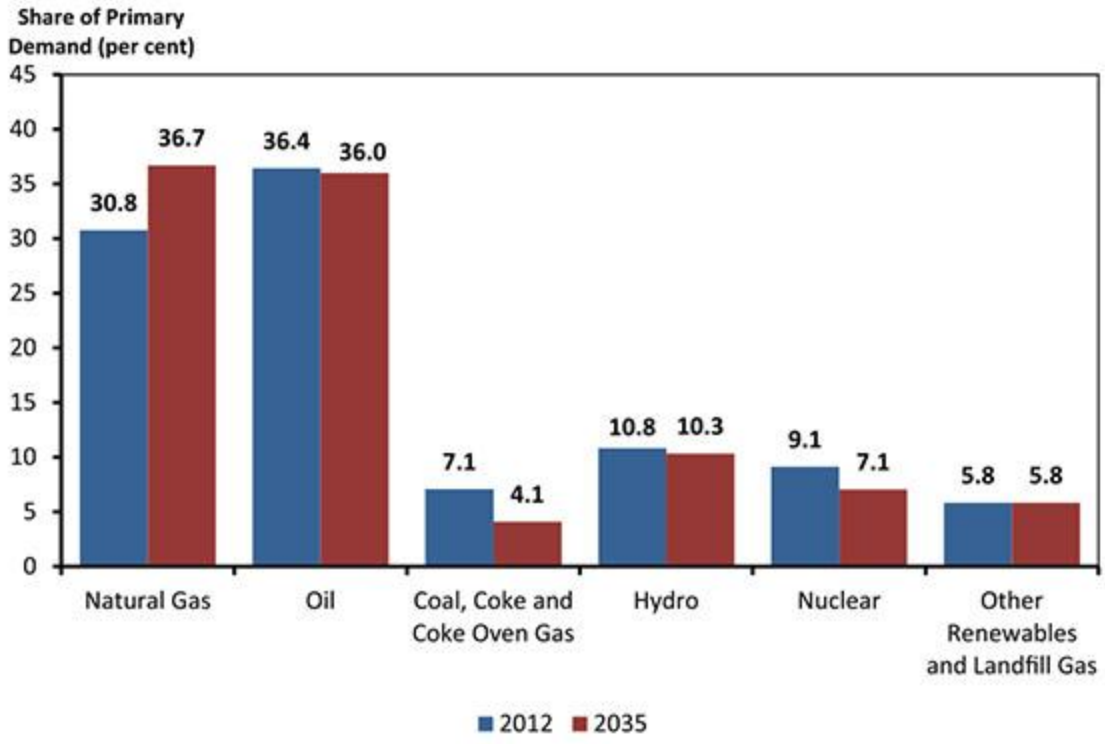
(g) and **(h)**

The level of investment in shale well production in the U.S. and return on those investments are not relevant to the Project, and YEC has not reviewed these matters.

(k)

Yukon Energy cannot speak specifically to what "others" may or may not do in the future.

The figure below provides the share of primary demand from 2012 and 2035 years as prepared by National Energy Board of Canada (NEB) as part of its Canada's Energy Future 2013 - Energy Supply and Demand Projections to 2035 - An Energy Market Assessment [November 2013][2].



NEB noted the following:

> Primary demand is calculated by adding the energy used to generate electricity (including hydro, nuclear, and renewable) to total end-use (or secondary) demand, and then subtracting the end-use demand for electricity. Removing end-use electricity demand from the total is necessary to avoid double counting.

[2] http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/nrgyftr/2013/nrgftr2013-eng.html#s2_2

(l)

The spike in gas prices this February in response to severe cold conditions in large areas of North America is well above the average over the past six months. The future price will reflect ongoing balancing of supply and demand such as has been shown over the past six months. The central question is the relationship between gas prices and diesel - and diesel fuel has also increased sharply in February. For example, Whitehorse fuel price in YEC's 2012/13 GRA was at $1.0513/litre compared to the February 2014 YEC price at $1.1933/litre (or 13.5% increase, a lot of which occurred in February) Please also see Figure 4-2 in the Application for projected longer term ratio between natural gas and oil prices.

(m)

The word "these forecasts" on page 41 of the Application refers to the natural gas and oil projections and their ratio as provided in Figure 4-2.

TOPIC:

REFERENCE: Page 42

"LNG development will reduce ratepayer exposure to severe and periodic drought related cost risk. ..."

PREAMBLE:

QUESTION:

a) Please confirm that any reduction in cost risk is dependent on the LNG power generation cost being lower than diesel generation cost.

b) Please confirm that new renewable energy generation in which there is no fuel cost (e.g. hydro, wind, solar PV) would reduce ratepayer energy related cost risks compared to LNG generation.

ANSWER:

(a)

Reduced ratepayer exposure to severe and periodic drought related cost risk would depend on the LNG fuel cost being lower than the diesel fuel cost.

(b)

The above referenced quote is specific to reducing ratepayer exposure to the costs of a severe drought. While renewable resources of generation such as hydro, wind and solar, may have low operating costs, these capital intensive projects if pursued in the near-term without sufficient long term and stable loads would result in material near term rate impacts for ratepayers. In different words, capital intensive renewable options depend on sustained use levels and would not normally be viewed as cost effective options to address drought related added non-hydro generation requirements.

Yukon Energy's Overview as filed in the 2012/2013 GRA highlights the extent to which sustained (e.g., 20+ years) and materially higher grid loads are required before capital intensive renewable resource options (e.g., greenfield hydro or wind) would be cost competitive options for ratepayers. Further detail regarding the specific conditions of the isolated Yukon grid and impact on economics of capital intensive project such as wind is provided in YCS/LE-1-59(a) Attachment 1 (which attaches the response to YCS-YEC-1-8 as filed in the 2012/2013 General Rate Application).

TOPIC:

REFERENCE: Page 42

"The project's LNG development cost savings could be enhanced ... or district energy heat sales are realized from LNG."

PREAMBLE:

QUESTION:

a) Please detail Yukon Energy's plans with respect to LNG based district heating.

b) Does Yukon Energy have the statutory authority to pursue any line of business other than the generation, transmission and distribution of electricity? If so please provide the relevant documentation.

c) If Yukon Energy does not have LNG based district heating plans please provide a detailed explanation as to why district heating should be referenced in this Application.

d) Please provide and discuss details of the possible lower cost gas prices that are referenced here.

ANSWER:

(a)

Yukon Energy completed in 2012 a district heat feasibility study for the City of Whitehorse in collaboration with the Yukon Government, the Energy Solution Center, the Yukon Research Center and the City of Whitehorse. As part of the YEC 2012 General Rate Application, the Board noted the following in Board Order 2013-01 Appendix A: Reasons for Decision:

> "Further, the Board is of the view that district heating is not the type of activity to which YEC should be applying resources nor expecting recovery from ratepayers since it is not related to electric generation or transmission of electricity."

Based on the views of the Board, no YEC resources were allocated to the analysis of heat recovery from the natural gas generation and integration to a district energy system in Whitehorse.

(b)

Please see response to part (a) above.

(c)

District heating is referenced as a potential future development that may or may not occur in Whitehorse (i.e., if not pursued by YEC may be pursued by others). Should this option be pursued, it would serve to enhance project benefits and reduce costs to ratepayers. YEC is not relying on district heating to support the business case for the Project.

(d)

The reference to the future forecast price of natural gas is with respect to the differential in Henry Hub price (a North American price benchmark for North American Gas) compared to the Brent Hub crude oil benchmark price, remaining at a 4 times differential, i.e. the price of crude oil remaining 4 times higher per energy unit than natural gas until 2040. This is a 2013 forecast coming from the US Energy Information Administration in their Annual Energy Outlook 2013.

TOPIC:

REFERENCE: Page 43

"LNG was identified in Yukon Energy's 2011 20-year Resource Plan as a potential source to displace near-term grid diesel requirements. It has been examined as a new fuel option that retains flexibility for power generation as well as diversity for energy use opportunities."

PREAMBLE:

QUESTION:

a) Please detail the energy use opportunities referred to and any role that Yukon Energy's might have in them.

b) The impression the readers get from this passage is that LNG will displace renewable energy generation that might otherwise be developed. Please discuss whether Yukon Energy's expectation is that LNG will displace more than the diesel generation that would be required (i.e. new renewable energy projects) in the absence of LNG generation.

ANSWER:

(a)

Introduction of LNG/natural gas supplies in Yukon may create longer-term development of natural gas use in the transportation and heating sectors, and may provide a source of supply for off grid mines. At this time Yukon Energy cannot indicate what, if any, role it would have outside of its continuing role to provide Yukoners with a sufficient supply of safe, reliable electricity and related energy services.

(b)

Development of the Project is not intended to displace renewable generation that would otherwise be developed.

In the near-term the Project will displace default diesel generation that would otherwise be required and operate in the same capacity as diesel generation facilities; it will provide reliable and flexible generation capacity to meet Yukon Energy's reserve capacity planning criteria for the Yukon grid, and provide generating capacity for seasonal low water periods and drought years, shorter term non-industrial load growth and peak winter demand.

As reviewed in the Application, Yukon Energy will continue to assess the economics of developing additional renewable generation supply options as soon as each is feasible and cost effective, including hydro enhancements at Mayo Lake and Marsh Lake, wind projects, and greenfield renewable projects to reduce both diesel and LNG requirements wherever possible.

TOPIC:

REFERENCE: Page 44

"November 20, 2013: The public review period was extended to December 20th to accommodate additional proposal information Yukon Energy submitted to YESAB on November 13, 2013."

PREAMBLE:

QUESTION:

a) Please confirm that what Yukon Energy is referring to here is submission to YESAB of a redesigned project to reflect the fact that Yukon Energy could not reach an Agreement with White Pass with respect to a lease (or purchase) of their property which Yukon Energy had assumed would be available to them.

b) Please confirm that YESAB, on receiving the redesigned project proposal, had do [sic] perform another adequacy review to ensure that their assessment could be done.

ANSWER:

(a) and **(b)**

Confirmed. There were modifications to the layout of the Expanded Site Area due to ongoing engineering and planning efforts to define and secure the lands required for the project. The changes included a reduced operational project footprint, which resulted in some site elements being reduced in size, orientation, and/or location within the operational parts of the Expanded Site Area, and correspondingly, an increase in the height of the vapour retention wall to ensure potential Project effects in this regard were properly mitigated. No other elements of the Project Proposal, its effects assessment supporting information or conclusions were substantively changed as a result of this evolution to a smaller project footprint.

A revised Project Proposal based on the above-noted modifications was submitted November 15, 2013, and on November 20, 2013, YESAB indicated to YEC it had completed a revised statement of scope and public notice for the Project. The public comment period was been extended to December 20, 2013 to accommodate a minimum 30 day period to review the revised Project Proposal.

As noted in response to YUB-YEC-1-47, the public comment period was further extended by YESAB on December 17, 2013 and concluded on January 10, 2014.

TOPIC:

REFERENCE: Page C-1:

PREAMBLE:

QUESTION:

a) Please provide a table of actual year over year non-industrial load growth from the time Yukon Energy assumed operations from NCPC in 1987. Please indicate where communities were added to the grid or other significant step changes in the number of customers occurred.

b) Please provide a table similar to Table C-2 projected out to 2054 (the full 40 year projected life of the Project) that provides Yukon Energy's projected peak demand forecasts and required installed capacity requirements to meet the N-1 planning criteria.

c) In Yukon Energy's history has there ever been a five period in which load growth averaged 2.45% as proposed for 2016 to 2020?

d) In Yukon Energy's history has there ever been a five period in which load growth averaged 2.82% as proposed for 2021 to 2025?

e) In Yukon Energy's history has there ever been a five year or greater period in which load growth averaged 3.13% such as proposed for 2026 and beyond?

f) Please provide the annual year over year load growth percentages net of DSM/SSE.

g) What is Yukon Energy's projection of winter load growth (reflecting changing patterns in electric heating) compared to summer load growth?

h) How has the higher increase in winter load growth affected Yukon Energy's calculations of diesel requirements in Table C-2?

i) How does Yukon Energy propose to deal with any disparity between winter and summer growth?

j) Please confirm that the base year for Marbek Conservation Review Potential study work referenced in Footnote 2 was 2010.

k) Is Marbek's particular expertise in load forecasting, and have they performed updated load forecasts based on more recent actual growth experience?

l) Given the rate increases customers have experienced over the last two years, the slowing mining economy, and significantly reduced home lot sales in the Whitehorse area, please provide detailed justification for Yukon Energy's projected non-industrial load growth.

ANSWER:

(a) and **(c)** through **(e)**

Please see Table 1 below for YEC non-industrial grid sales and Fish Lake load for 1994-2013 years.

Table 1:
YEC Non-Industrial Grid Sales and Fish Lake Load

Years	YEC Non-Industrial Sales (GW.h)	YECL Fish Lake (GW.h)	Total Yukon Grid Non-industrial Sales (GW.h)	Annual Change (%)
1994	232.5	10.2	242.7	
1995	239.8	7.1	246.8	1.7%
1996	260.1	6.6	266.8	8.1%
1997	247.9	6.3	254.2	-4.7%
1998	248.5	5.6	254.1	-0.1%
1999	247.2	4.5	251.7	-0.9%
2000	243.7	6.9	250.6	-0.4%
2001	244.8	9.2	253.9	1.3%
2002	247.8	8.6	256.4	1.0%
2003	257.4	4.9	262.3	2.3%
2004	263.6	5.8	269.4	2.7%
2005	266.2	6.9	273.1	1.4%
2006	279.8	8.2	288.0	5.5%
2007	283.5	9.0	292.5	1.6%
2008	293.8	6.6	300.3	2.7%
2009	299.1	8.1	307.2	2.3%
2010	310.7	3.4	314.1	2.3%
2011	324.9	3.6	328.5	4.6%
2012	346.1	3.4	349.5	6.4%
2013	344.0	3.7	347.7	-0.5%

Notes:
1. Sales decline in 1997-2000 years explained by Faro mine closure.
2. YEC retail sales include Faro site dewatering sales after Faro Mine closure charged as "Industrial" prior to 2005.
3. Includes Pelly Crossing starting late 2008.
4. 2013 numbers are preliminary.

Table 1 shows that the annual change in non-industrial load for the last 5 years averages to about 3.2%, and last 10 years averages to about 3%.

(b)

Please see response to YCS/LE-YEC-1-35(a).

(f)

Please see Table 2 for the requested information.

Table 2:
Non-Industrial Load Growth Forecast Net of DSM/SSE

Forecast Years	Non-industrial Load Growth - net of DSM/SSE (%)
2013	
2014	2.2%
2015	2.1%
2016	2.0%
2017	1.8%
2018	1.8%
2019	1.8%
2020	1.8%
2021	2.1%
2022	2.1%
2023	2.1%
2024	2.1%
2025	2.2%
2026	2.4%
2027	2.4%
2028	2.5%
2029	2.5%
2030	2.5%

(g) through **(i)**

YEC did not do additional adjustments to the load forecast to reflect more electric heating usage which would result more energy consumption in winter time. ICF Marbek in its report[1] notes that the growth rates in the report are higher than YEC's 2011-2030 Resource Plan growth rate largely due to electric heated dwellings incorporated in Marbek's forecast.

[1] YECL 2013-15 GRA, Appendix G1

Higher winter load would results in higher thermal generations, which in turn increase benefits from LNG Project.

(j)

Confirmed.

(k)

Marbek was retained to provide a market characterization study, conservation potential review study and a DSM plan, relying on sales information provided by YEC and YECL. Yukon Energy cannot speak to Marbek's load forecasting expertise and Marbek has not been used in updating load forecasts.

(l)

As provided in Table 2, the non-industrial load net of DSM/SSE is forecast to increase by about 1.8%-2.2% for the next 10 years. This is lower than average non-industrial load increase for the last 10 years, which is about 3% as provided in Table 1 above - although the updated forecast includes impacts from new DSM. The load forecast in Appendix C is prepared based on best available data and provides a reasonable load forecast for the purpose of the Application.

TOPIC:

REFERENCE: Page C-1 Sensitivity of project economics to load growth

PREAMBLE:

QUESTION:

a) Please provide additional versions of Table 4-3 based on the following load growth scenarios:
   i. Non-industrial net (after DSM and SSE savings) load growth of 2.0% from 2016 forward;
   ii. Non-industrial net load growth of 1.5% from 2016 forward; and
   iii. Non-industrial net load growth of 1.0% from 2016 forward.

ANSWER:

(a)

Please see Attachment 1 to this response for the requested analysis.

The attachment includes three tables:

- **Table 1** with assumed 2% non-industrial load growth net of DSM/SSE for 2016-2018 years [the ratepayer benefits higher by about $0.055 million for 2017 and 2018 years compared to Table 4-3];

- **Table 2** with assumed 1.5% non-industrial load growth net of DSM/SSE for 2016-2018 years [the ratepayer benefits lower by about $0.140 million for 2016, $0.077 million for 2017 and $0.085 million for 2018 compared to Table 4-3];

- **Table 3** with assumed 1% non-industrial load growth net of DSM/SSE for 2016-2018 years [the ratepayer benefits lower by about $0.249 million for 2016, $0.210 million for 2017 and $0.226 million for 2018 compared to Table 4-3].

Table 1: Ratepayer Impacts from Whitehorse Diesel-Natural Gas Conversion Project ($million)
(Project compared to New Diesel Alternative)

(non-industrial load forecast after DSM/SSE increased by 2% for 2016-2018 years)

		2014	2015	2016	2017	2018
Capital cost ($million) at yr end						
Total	Diesel (new)	22.55	11.1			
	LNG	34.36		4.4		
Net	Diesel (new)	22.55	33.1	32.3	31.5	30.7
	LNG	34.36	33.5	37.1	36.2	35.2
Annual Capital Cost ($million)						
Deprec	Diesel (new)		0.527	0.805	0.805	0.805
	LNG		0.823	0.823	0.933	0.933
Return	Diesel (new)		1.517	1.783	1.739	1.695
	LNG		1.850	1.925	1.997	1.946
Total	Diesel (new)		2.044	2.588	2.544	2.500
	LNG		2.673	2.748	2.930	2.879
Difference (LNG-Diesel)			**0.629**	**0.160**	**0.386**	**0.379**
Annual Fuel Cost ($million)						
Diesel Estimate (GWh)			17.0	22.9	27.4	31.9
% New	Diesel (new)		90%	100%	100%	100%
	LNG		100%	95%	100%	100%
Fuel Cost	Diesel (new)		4.252	5.633	6.740	7.847
	LNG		2.295	3.266	3.699	4.307
Difference (LNG-Diesel)			**-1.957**	**-2.368**	**-3.041**	**-3.541**
Net Ratepayer Impact ($million)						
	Diesel (new)		6.296	8.221	9.284	10.348
	LNG		4.968	6.014	6.629	7.186
Difference (LNG-Diesel)			**-1.328**	**-2.208**	**-2.655**	**-3.162**

Notes:

1. All capital costs depreciated over 40 years; return on mid-year rate base at 5.45%/year.
2. Diesel fuel costs at 24.6 c/kWh new diesel, 28.7 c/kWh other diesel.
3. LNG delivered fuel costs at 13.5 c/kWh (assumes supply from Shell Canada at Calgary at an AECO gas price of $4.50 per MMBtu and using A-Train units for delivery to Whitehorse).
4. Diesel estimated based on non-industrial load forecast after DSM/SSE increased by 2% for 2016-2018 years plus industrial load as provided in Appendix C of Part 3 Application.

Table 2: Ratepayer Impacts from Whitehorse Diesel-Natural Gas Conversion Project ($million)
(Project compared to New Diesel Alternative)

(non-industrial load forecast after DSM/SSE increased by 1.5% for 2016-2018 years)

		2014	2015	2016	2017	2018
Capital cost ($million) at yr end						
Total	Diesel (new)	22.55	11.1			
	LNG	34.36		4.4		
Net	Diesel (new)	22.55	33.1	32.3	31.5	30.7
	LNG	34.36	33.5	37.1	36.2	35.2
Annual Capital Cost ($million)						
Deprec	Diesel (new)		0.527	0.805	0.805	0.805
	LNG		0.823	0.823	0.933	0.933
Return	Diesel (new)		1.517	1.783	1.739	1.695
	LNG		1.850	1.925	1.997	1.946
Total	Diesel (new)		2.044	2.588	2.544	2.500
	LNG		2.673	2.748	2.930	2.879
Difference (LNG-Diesel)			**0.629**	**0.160**	**0.386**	**0.379**
Annual Fuel Cost ($million)						
Diesel Estimate (GWh)			17.0	21.6	26.2	30.6
% New	Diesel (new)		90%	100%	100%	100%
	LNG		100%	95%	100%	100%
Fuel Cost	Diesel (new)		4.252	5.301	6.446	7.536
	LNG		2.295	3.073	3.537	4.136
Difference (LNG-Diesel)			**-1.957**	**-2.228**	**-2.908**	**-3.400**
Net Ratepayer Impact ($million)						
	Diesel (new)		6.296	7.889	8.990	10.036
	LNG		4.968	5.821	6.467	7.015
Difference (LNG-Diesel)			**-1.328**	**-2.068**	**-2.522**	**-3.021**

Notes:

1. All capital costs depreciated over 40 years; return on mid-year rate base at 5.45%/year.
2. Diesel fuel costs at 24.6 c/kWh new diesel, 28.7 c/kWh other diesel.
3. LNG delivered fuel costs at 13.5 c/kWh (assumes supply from Shell Canada at Calgary at an AECO gas price of $4.50 per MMBtu and using A-Train units for delivery to Whitehorse).
4. Diesel estimated based on non-industrial load forecast after DSM/SSE increased by 1.5% for 2016-2018 years plus industrial load as provided in Appendix C of Part 3 Application.

Table 3: Ratepayer Impacts from Whitehorse Diesel-Natural Gas Conversion Project ($million)
(Project compared to New Diesel Alternative)

(non-industrial load forecast after DSM/SSE increased by 1% for 2016-2018 years)

		2014	2015	2016	2017	2018
Capital cost ($million) at yr end						
Total	Diesel (new)	22.55	11.1			
	LNG	34.36		4.4		
Net	Diesel (new)	22.55	33.1	32.3	31.5	30.7
	LNG	34.36	33.5	37.1	36.2	35.2
Annual Capital Cost ($million)						
Deprec	Diesel (new)		0.527	0.805	0.805	0.805
	LNG		0.823	0.823	0.933	0.933
Return	Diesel (new)		1.517	1.783	1.739	1.695
	LNG		1.850	1.925	1.997	1.946
Total	Diesel (new)		2.044	2.588	2.544	2.500
	LNG		2.673	2.748	2.930	2.879
Difference (LNG-Diesel)			**0.629**	**0.160**	**0.386**	**0.379**
Annual Fuel Cost ($million)						
Diesel Estimate (GWh)			17.0	20.5	25.0	29.4
% New	Diesel (new)		90%	100%	100%	100%
	LNG		100%	95%	100%	100%
Fuel Cost	Diesel (new)		4.252	5.040	6.152	7.224
	LNG		2.295	2.922	3.376	3.965
Difference (LNG-Diesel)			**-1.957**	**-2.119**	**-2.776**	**-3.260**
Net Ratepayer Impact ($million)						
	Diesel (new)		6.296	7.628	8.696	9.725
	LNG		4.968	5.670	6.306	6.844
Difference (LNG-Diesel)			**-1.328**	**-1.958**	**-2.390**	**-2.881**

Notes:

1. All capital costs depreciated over 40 years; return on mid-year rate base at 5.45%/year.
2. Diesel fuel costs at 24.6 c/kWh new diesel, 28.7 c/kWh other diesel.
3. LNG delivered fuel costs at 13.5 c/kWh (assumes supply from Shell Canada at Calgary at an AECO gas price of $4.50 per MMBtu and using A-Train units for delivery to Whitehorse).
4. Diesel estimated based on non-industrial load forecast after DSM/SSE increased by 1% for 2016-2018 years plus industrial load as provided in Appendix C of Part 3 Application.

TOPIC:

REFERENCE: Page C-5 Table C-2

PREAMBLE:

QUESTION:

a) Please extend the Base Case of Table C-2 to 2054, i.e. the full 40 year projected life of the proposed Project.

ANSWER:

(a)

Please see response to YCS/LE-YEC-1-35 (a).

TOPIC:

REFERENCE: Page C-7 Future diesel retirements

PREAMBLE:

QUESTION:

a) When Whitehorse diesels #4 through #7 are retired in due course will building space allow them to be replaced with larger capacity generators (e.g. Caterpillar 4.4 MW 3616s)?

ANSWER:

(a)

Ahead of the retirement of units 4 through 7, YEC will need to do a review of the condition of the building, foundation and auxiliary systems to understand the feasibility of replacing the aging diesel units with new natural gas fired engines. Space available in each service bay then would also need to be considered to assess what engine unit options could potentially be considered.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) Please provide the final budget, report and results of Yukon Energy's 2011 Energy Charrette.

b) Please provide the final budgets, reports and results of the subsequent "mini-Charrettes" on biomass, waste-to-energy, DSM, LNG, and wind.

ANSWER:

(a) and (b)

The costs of these items were reviewed in detail as part of the 2012/13 General Rate Application and have no bearing on the scope of this proceeding as defined in the terms of reference established by the Minister. The charrette and mini-charrette reports are publically available on the YEC website.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) Please provide all the Yukon Energy Board of Directors resolutions with dates and associated materials pertaining to the LNG project.

ANSWER:

(a)

The requested documentation cannot be provided. Documentation provided to Yukon Energy's Board (including minutes of Board meetings and board resolutions) has never been provided in previous YUB proceedings. The reasons for this include issues relating to Board confidentiality, proprietary information, and privacy.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) Please provide the date and agenda for the Electrical Thermal Storage and Load Management workshop that Yukon Energy is co-sponsoring.

ANSWER:

(a)

The workshop on Electrical Thermal Storage will be held on May 13 -14, 2014. YEC is a funding partner and is providing advice on the workshop; however, the workshop is being organized by a third party. The agenda for the workshop has not been finalized.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) Please provide the analyses and supporting materials from Yukon Energy's 2011 Resource Plan that led to the conclusion that the levelized cost of wind energy would be $0.40 per kWh.

b) Please provide the data obtained from the meteorological wind assessment tower installed at the Techo site since its installation.

c) Please provide the unredacted Wind Assessment Feasibility Study Final Report dated January 2009 about wind potential on Mt Sumanik.

ANSWER:

(a)

Analysis and supporting materials from Yukon Energy's 2011 Resource Plan that led to the conclusion that the levelized cost of wind energy would be $0.40 per kWh were provided in response to an interrogatory request filed during the 2012/2013 General Rate Application (YCS-YEC-1-8). This is provided as Attachment 1 to this response.

(b)

Winter data collection at Techo is ongoing. Yukon Energy is waiting to have a complete dataset before proceeding with the analysis of the data and confirming potential power benefit.

(c)

The redacted Wind Assessment Feasibility Study Final report dated January 2009 about wind potential on Mt Sumanik was provided as a response to an information request YCS-YEC-1-1 during the 2012/2013 General Rate Application and is publically available. Yukon Energy is not able to provide the unredacted version of this study as it contains proprietary and commercially sensitive information.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) If the answers to questions 3 to 7 are no, YCS would like to know why, considering the conclusion of the study is that a wind project on Mt. Sumanik would be economic relative to base load diesel (even with diesel prices as low as $0.75 per litre), that the wind resources during the entire year on Mt. Sumanik match the electrical load, and that there is every reason to further pursue a wind project on Mt. Sumanik (especially due to its proximity to the predicted large load of new residential/commercial development in Whitehorse and the predominance of electrical heat).

ANSWER:

(a)

Yukon Energy has fully recognized the need to assess the wind potential in the Yukon to determine whether, and when, it is a viable resource option to meet near-term or longer term grid requirements, given the range of options available to meet these requirements.

Yukon Energy's assessments to date have confirmed at a preliminary level potential 20-21 MW alternatives at two sites (Ferry Hill and Mount Sumanik), as well as a potential smaller scale "first stage" alternative (10 MW) that could potentially be pursued at each of these sites. To reduce project expense and risk, prior to investing material time and financial resources to complete baseline data collection and related activities to support a regulatory submission, Yukon Energy has recognized that it must better understand the wind resource potential at these sites. Based on preliminary assessments, and the expectation that only one such site at best can be accommodated on the grid during the current 20-year planning period, Yukon Energy has focused its current ongoing wind monitoring work at Ferry Hill. As such, efforts are currently directed at further wind monitoring at the Ferry Hill site in order to move forward on Phase 1: Project definition of the Corporation’s Project Planning & Development framework. Please see response to

YUB-YEC-1-40(b) for more information on YEC's development phases for feasibility study projects.

In summary, over the past 3 years, the Corporation has invested material resources to better understand the potential for wind. Yukon Energy is committed to further investigate wind resource at Ferry Hill. In combination with wind monitoring at the site, the Corporation is investigating other ancillary systems (e.g. diesel rotary uninterruptible power system) that would be required with the development of a large wind farm to ensure grid stability and reliability in instances where generation is suspended as a result of wind lulls. These ancillary systems, once included in the overall project cost, contribute to a material increase in cost of energy for wind energy that nonetheless, at some potential grid loads, remains less than the cost of diesel generation but higher than other energy generation options.

An overview of Yukon Energy's current assessments of the Ferry Hill wind resource potential, and how this matches with grid diesel displacement forecast over a year and the life of a wind project, is provided below.

Overview of Current Wind Potential Assessments

Subsequent to the 2011 Wind Feasibility Study, Yukon Energy engaged in a resource planning process which led to the development of the draft 2011 20-Year Resource Plan: 2011-2030. This resource planning process relied upon costs and other information referenced in the 2011 Wind Feasibility Study for development of a wind resource in Yukon. The cost effectiveness of development of a wind resource in Yukon was assessed based on information available at the time and considered diesel displacement opportunities and project benefits under various forecast load scenarios.

The results of this resource planning process are summarized in the 2011 20-Year Resource Plan: 2011-2030 Overview provided as an attachment to YECL-YEC-1-18.

As discussed at the Energy Charrette, wind is generally assessed to be not reliable as to delivery of power (not add to peaking capacity, not storable, needs added costs to provide related storage, medium cost (Full Utilization LCOE at 15+ cents/kW.h), not flexible (capital intensive option, not dispatchable, high costs per net kW.h of useful energy when minimal diesel to displace), but relatively low on regulatory risk as to approvals, and high on environmentally responsibility (renewable energy option with very

low GHG emissions). For a 20-21 MW wind project on the Yukon grid, it is estimated that Yukon Energy would likely also require a new diesel rotary uninterruptible power supply (DRUPS) units (estimated cost of $2 million per MW).

The 2011 Resource Plan summarizes YEC's current assessment of a 21 MW wind farm at Ferry Hill, assuming 14 GE 1.5 MWxle wind turbines; gross annual energy capability estimated at 68.70 GW.h before losses, and 55.60 GW.h after all losses (includes 9% downtime, icing losses averaging 7.8%, and other losses – average capacity factor approximates 30.2%). Initial wind monitoring indicates higher useful wind energy generation in winter months than in summer months. Capital costs (2010$) are estimated at $83.42 million ($3.97 million per MW) before consideration of spinning reserve or other added energy storage requirements (see below), including 10% contingency and provision for turbine de-icing system, transmission/substation improvements (with transmission connection to Stewart Crossing south substation), development and permitting, engineering/construction management at 12% and owner's costs at 7%). Annual operating costs (2010$) estimated at $2.1 million (about $38/MW.h). Financial analysis assumes a 25 year life. In assessing a 20-21MW wind site on the Yukon grid, $10 million is added to the capital cost to provide for a minimum 5 MW of DRUPS to ensure adequate spinning reserve to integrate the site on the grid.

If the Yukon grid was able to use all of the Ferry Hill wind generation to displace diesel generation over the life of the project, this resource option would be economic based on the above preliminary cost assessments, i.e., the average levelized cost of energy (LCOE) for this wind resource over its assumed 25 year life, based on full use of all its generation to displace diesel and the above cost estimates, is 14.8 cents/kWh in 2010$. This LCOE at full utilization of the wind resource is well below the expected equivalent cost of diesel fuel and O&M (assumed at 28 cents per kWh in 2010$ in the 2011 Resource Plan).

However, the 2011 Resource Plan reviews the impact of the isolated Yukon grid where generation that cannot be used to meet Yukon grid loads is effectively "spilled" (as occurs with surplus hydro generation on this grid) and has no value.

In the context of the Yukon grid, new wind generation derives economic value by displacing diesel generation that would otherwise be required (based on long term average hydro generation estimated at the forecast grid loads). To be potentially attractive, 21 MW of new wind generation at Ferry Hill would require major new loads on

the grid – for the purpose of the following analysis, Scenario A loads as presented in the 2011 Resource Plan are adopted (assumes connection of Victoria Gold mine load by 2015, the assumed time when the wind generation commences service).

Even when the new mine loads are on the grid during the 2015-19 time period, the figure below (from the Overview, Figure 5-3) demonstrates that the 21 MW wind generation would not be fully utilized to displace diesel generation under Scenario A loads (even when DSM/SSE is excluded). This reflects the combined impact of seasonal (weekly) loads, seasonal (weekly) hydro generation under long term average conditions, and seasonal (weekly) average wind generation.

- Annual available wind generation assumed at 55.8 GW.h from the 21 MW facility.

- 34.8 GW.h directly displaces diesel (focused during winter months when over 95% of diesel generation would otherwise occur).

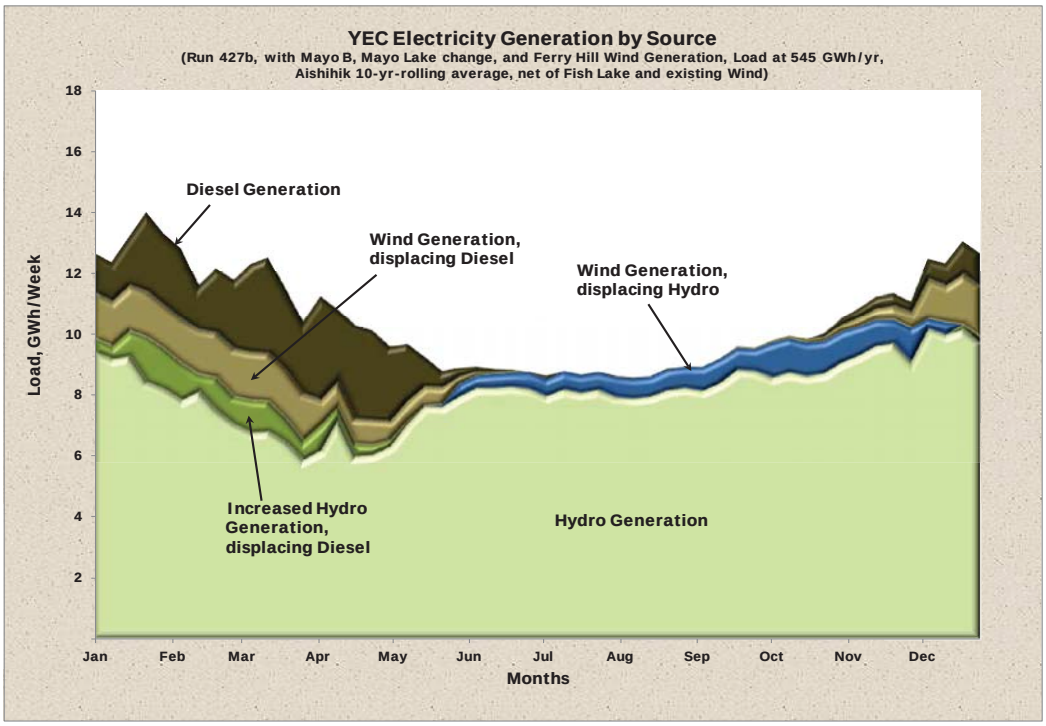
- The balance of the wind generation would “displace” hydro generation; 14.6 GWh of the displaced hydro (typically during summer months) would be forecast to enhance hydro storage that would then be used to displace diesel during winter months - the remaining 6.6 GW.h would be forecast to have no value in displacing diesel at this Scenario A load.

- In total 49.2 GW.h of forecast wind generation would be forecast to displace diesel during these years at the Scenario A forecast grid load.

- 52 GW.h of diesel energy generation requirements would remain on the grid under this assumed load and scale of wind generation (assumed Mayo Lake enhanced storage is in place, but excludes any DSM/SSE).

- Unlike diesel, the 21 MW of new wind generation is dependent at all times on wind availability and therefore does not contribute to grid reliable capacity requirements, i.e., diesel or other new reliable capacity is needed during these years at this load o address diesel unit retirements plus added capacity requirements from growth. Only the 5 MW DRUPS contributes towards the projected 12.8 to about 27 MW of new reliable capacity required during this time period with this assumed grid load (Table 5-1 in Overview).

YEC Grid Electricity Seasonal Generation by Source: Mean Flows (average of all water years) with 21 MW Wind Project Displacing Diesel and Displacing Hydro at Scenario A 2015-16 Load Without DSM/SSE



Grid Generation at 545 GW/h load* (GW.	Without Wind Project	With 21 MW Wind Project	Change
Grid Load	545.0	545.0	
Grid Generation			
Hydro*	443.9	437.3	(6.6)
Diesel	101.1	51.9	(49.2)
Wind*	-	55.8	55.8
Total	545.0	545.0	

Breakdown of Wind Generation Impacts (GW.h/yr)	
Directly Displacing Diesel	34.6
Directly Displacing Hydro	
Stored Hydro Displacing Diesel	14.6
Spilled Hydro (not required)**	6.6
Total Wind Project Generation	55.8

* Existing Wind and Fish Lake generation not included.

Total Displaced Diesel = 34.6 + 14.6 = 49.2 GW.h

**This figure provides an example that illustrates impacts this supply option would have on the existing generation system; This does not suggest YEC would operate the system in a manner that results in hydro being displaced by other forms of more costly generation

The economic benefits of the 21 MW wind resource are also affected by the forecast grid loads (and related diesel generation otherwise forecast to be required) over the assumed 21 year life of the wind resource.

The following figure (Figure 6-4 from the Overview) demonstrates over a 25 year life how full utilization generation for this wind resource varies from forecast net diesel displaced with Scenario A loads with maximum potential DSM/SSE as assumed in the 2011 Resource Plan (highlights the impact of assumed all mines shutdown after 2020 when

the wind resource has no flexibility to limit its ongoing generation or costs). Based on the diesel displacement in this figure with the assumed grid load, the estimated LCOE (2010$) for the 21 MW wind project increases to 40.0 cents per kW,h of diesel displaced, i.e. the resource over its life is more costly than diesel at the assumed 28 cents/kWh LCOE for fuel and O&M costs.

Wind Project: Displacing Diesel and Hydro at Scenario A Load with DSM/SSE (current forecast mine life, no mine loads after 2021)

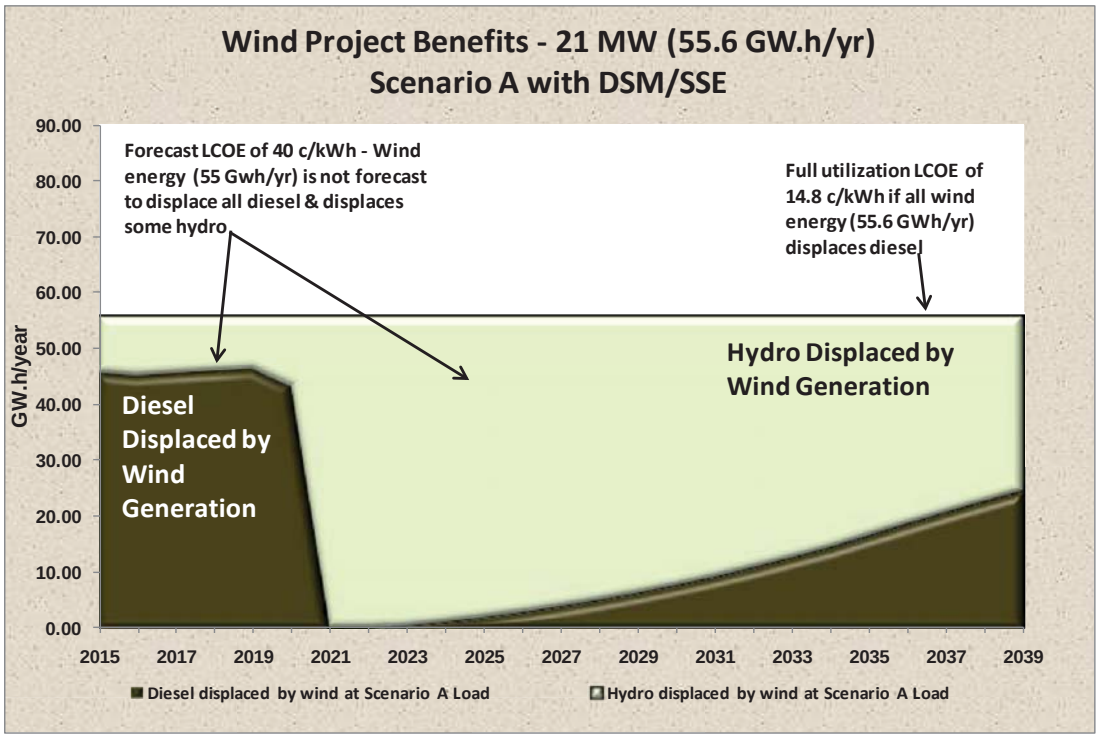


Table 8-1 and Table 8-2 in the Resource Plan Overview document provide an overview assessment of wind compared to other potential resource options and indicate as follows with regard to development of a 21 MW wind project (including 5 MW of DRUPS) to provide annual energy capability of 56 GWh with 5 MW of reliable peak winter capacity:

- Based on Scenario A with assumed DSM/SSE grid loads as defined in the Resource Plan annual costs (based on cents/ kWh of forecast diesel displaced) for the years 2015-2019 range between 26 and 29 c/kWh, i.e., slightly less than diesel fuel and O&M costs at 29-31 cents per kW.h, but higher than costs

estimated for Marsh Lake Storage (15-16 c/kW.h), Gladstone Diversion (14 c/kW.h) or LNG (17 c/kW.h).

- Based on Scenario A and Scenario B grid loads with assumed DSM/SSE as defined in the Resource Plan, LCOE (2010$) over the life of the project (based on cents/kWh of forecast diesel displaced) is more expensive than diesel, e.g., at 36.5 to 40 cents/kWh for Scenarios B and A respectively. This outcome reflects the impact of assumed mine load shut down after 2020 as well as assumed ongoing DSM/SSE; for example:
  - If Scenario A grid loads with DSM/SSE forecast for 2019 are extended to 2030, the LCOE (2010$) for wind drops to 21.3 c/kW.h; and
  - If Scenario A loads are assumed without any DSM/SSE to reduce future diesel generation, the LCOE (2010$) for wind drops to 19.6 c/kW.h.

- The 2011 Resource Plan analysis highlights the impacts on wind project economics of Yukon's isolated grid, limited loads, and variable hydro generation (both seasonal and annual variability). In contrast to forecast LCOE that take into account Yukon-specific grid conditions, a full utilization LCOE (of the type typically adopted in resource-specific feasibility studies) for a 21 MW wind project at Ferry Hill drops to 14.8 c/kW.h (2010$).

The 2011 Resource Plan Overview recommends that current Ferry Hill wind monitoring be completed in order to have this project shelf-ready to pursue through regulatory submissions and other development activity at such time as grid loads and other relevant conditions indicate that this project would be cost-effective to implement. It is also recommended that YEC continue to examine for initial development the feasibility of smaller wind projects in the range of 10 MW to meet suitable grid loads.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) What activities is Yukon Energy undertaking to electrify Yukon's economy with renewable electricity?

b) Does Yukon Energy have a mandate with respect to 'sustainable development' and if so please describe Yukon Energy's understanding of the meaning of the term.

ANSWER:

(a)

YEC has completed a number of projects that meet this objective; in the last ten years, the following projects have directly contributed to lowering the territories' reliance on fossil-fuel based generation:

- Mayo to Dawson transmission line;
- Carmacks to Stewart Crossing transmission project; and
- Mayo B hydro enhancement project.

As well the utility has and will continue to investigate renewable options such as the following:

- Wind;
- Geothermal;
- Waste-to-Energy; and
- Hydro storage enhancements.

The ability to advance these technologies beyond planning stages will depend on expected system load characteristics and the economics of the technology involved.

(b)

Section 5(c) of the Development Corporation Act states: "The objects for which the corporation is established are to participate with the private sector in the economic development of the Yukon and, in particular,…to assure a continuing and adequate supply of energy in the Yukon in a manner consistent with sustainable development."

Yukon Energy is committed to sustainability (often termed sustainable development), which for the Corporation means pursuing innovative business strategies and activities that meet the needs of customers, stakeholders, and the communities in which we operate today, while protecting and enhancing the human and natural resources that will be needed in the future.

Yukon Energy will continue to improve its overall sustainability performance by committing to the following principles:

1. **Environment**: Minimize the adverse environmental impacts of our facilities, operations and businesses.

2. **Stewardship and Biodiversity**: Manage the environmental resources and ecosystems that we affect to prevent or minimize loss and support recovery.

3. **Climate Change**: Manage greenhouse gas emissions to mitigate the impact of operations on climate change, while adapting to its effects.

4. **Health and Safety**: Provide a safe and healthy workplace for our employees and contractors.

5. **Workplace**: Support a fair, respectful and diverse workplace for our employees and contractors.

6. **Communications and Engagement**: Communicate with and engage our stakeholders in a transparent and timely manner.

7. **Aboriginal Relations**: Communicate with and engage First Nations governments and citizens in a manner that respects their culture and traditions.

8. **Economic Value**: Provide economic benefits to shareholders, communities, and regions in which we operate.

9. **Energy Efficiency**: Produce, deliver, and use electricity in an efficient manner while promoting conservation and demand side management.

10. **Security of Supply**: Provide electricity to customers in a safe, reliable and cost effective manner to meet current and future needs.

Yukon Electrical Company Limited
(YECL)

TOPIC:

REFERENCE:

PREAMBLE:

YECL would like to understand more about Yukon Energy's capital replacements and retirements for diesel generation.

QUESTION:

a) Please describe the system planning criteria and the parameters that are factored when considering replacement of existing diesel generation units.

b) What factors were considered in determining the capacity of the new natural gas-fired generating units?

c) Are the existing units (WD1 and WD2) being retired based on overall condition, lifetime operating hours, and forecast operating hours or due to obsolete equipment considerations?

d) Please provide a list of forecasted retirement dates for all existing diesel generation units including location and capacity of each unit.

e) For all diesel generating units, please provide the typical maintenance intervals for all required rebuilds.

ANSWER:

(a)

Capacity planning criteria adopted by Yukon Energy were reviewed by the Yukon Utilities Board in its review of Yukon Energy's 2006 20-Year Resource Plan, and consequently addressed in the recommendations from the YUB to the Minister of Justice dated January 15, 2007. Absent major new mine loads, the determinative requirement is that the grid be planned to be able to carry the forecast peak winter loads (excluding

major industrial loads) under the largest single contingency (known as "N-1"), i.e., assuming the loss of the system's single largest generating or transmission-related generation source (currently Aishihik generating capacity loss through failure of Aishihik-Whitehorse transmission).

Yukon Energy identified the need to replace or significantly refurbish its aging grid diesel generating units as part of its 2006 20-Year Resource Plan filing with the YUB. When the Mirrlees units (the oldest installed diesel units) were evaluated, WD3 was deemed to be in the best condition and was refurbished in 2010. Ongoing load growth on the grid resulted in increased use of diesel to meet peak demand and advanced the need to replace the remaining Mirrlees units (MD1 and WD2 both in service in 1968) when retired with more efficient, reliable capacity.

The Application, Section 4.1.4 and Appendix C, review the forecast new grid capacity required under Base Case load scenarios without major new mines. The discussion notes, Whitehorse diesel generation capacity to be retired in 2014/2015 (WD1 and WD2) and ongoing non-industrial load growth result in a requirement for at least 7.0 MW of new generation capacity on the grid by late 2014, 8.5 MW by late 2015, 10.9 MW by late 2016, and 13.0 MW by late 2017 to maintain grid system capacity needed for forecast non-industrial peak winter loads.

(b)

The factors considered in determining the capacity required for the new natural gas-fired generating units were as follows:

- Reserve capacity requirement for grid (pending generation retirements and higher peaks);
- Connection costs to grid;
- Use of existing infrastructure and human resources;
- Unit operation in wide range of operating scenarios;
- Capital cost;
- Operating costs & fuel efficiency; and
- Maintenance intervals/costs.

(c)

Primary considerations are overall condition and obsolete equipment.

(d)

Please see Attachment 1 to this response which provides the diesel retirement schedule from page 42 of the 2011 Resource Plan.

(e)

Maintenance schedules for Yukon Energy's diesel fleet are as follows:

- Cat 3500 engines - minor overhauls at 6000 hours, major overhauls at 12,000 hours.
- Cat 3600 engines - minor overhauls at 8,000 hours, major overhauls at 16,000 hours.
- EMD engines - minor overhauls at 10,000 hours, major overhauls at 20,000 hours.
- Mirrlees engines - minor overhauls at 2/4/6/12,000 hours major overhauls at 24,000 hours.

TOPIC:

REFERENCE: YEC Application – 3.1 Project Summary Description

PREAMBLE:

Yukon Electrical would like to understand the rationale for selecting single fuel natural gas generating units instead of dual fuel units able to utilize natural gas or diesel fuel.

QUESTION:

a) Please explain why YEC is not proceeding with dual fuel units to provide fuel optionality with respect to future price variability of diesel and natural gas or an extended break in the supply chain of LNG.

b) Can LNG be stored indefinitely? If no, how long? Please discuss the risks and probability of YEC having LNG that cannot be used for generation. What does YEC intend to do with LNG that reaches the end of its storage life?

c) What does YEC intend to do if there is an extended disruption to the supply of LNG beyond the storage capacity of the project?

ANSWER:

(a)

Please see response to YCS/LE-YEC-1-5.

(b)

LNG can be stored for considerable periods of time, subject to the boil off gas being released to keep the LNG cold. Yukon Energy cannot envisage any scenario where it would have to remove LNG from its storage tanks due to the LNG being at the end of its storage life. A more detailed description of the LNG aging was answered previously in an IR response to YESAB in October of 2013 and the relevant excerpt is provided below

for reference. Yukon Energy can now confirm the guaranteed boil off rate of the LNG stage tanks is less than 0.15% per day. Please also see response to YUB-YEC-1-35.

Excerpt of YESAB Supplementary Information Request - filed October 10, 2013 with YESAB.

Item 2a: Project Design – LNG Composition from Jumping Pound Supply

The composition of fuel from the Jumping Pond supply may affect the consideration of storage/vaporization design of the facility. Also the fuel composition may affect the management of fuel aging. What is the LNG composition range and how has YEC considered the composition of the supply fuel in the project design and project management related to potential fuel aging?

Yukon Energy does not expect that the precise LNG fuel composition as delivered will affect the final design of the storage and vapourization facilities.

Yukon Energy is proceeding with design of the storage/vapourization facility assuming that LNG as delivered is likely to have a composition of not less than 95% methane, and contain no more than 4% ethane and 1/2% of other hydrocarbons, with the balance to be inert gases. Additional information is provided below to explain why an ability to meet this general LNG fuel specification will not affect final design of the storage and vapourization facilities.

To start with, it is reasonable to assume that on average at least 20% of the LNG volume is likely to turn over per week under forecast scenarios described in the YESAB Project Proposal[1], and the entire LNG inventory would therefore be likely to turn over at least approximately once per month. Consequently, no aging concentration issues related to safety or process considerations are expected under average forecast scenarios.

If for whatever reason, however, the LNG inventory does not turn over on a monthly basis, LNG can be held in tanks for several months before it is lost through boil off or used for power generation or other purposes. The maximum boil off rate is expected to be 0.25% per day for the LNG tanks (and could be as low as 0.1% per day depending on

[1] Minimum average weekly LNG deliveries for 2015 Base Case forecast grid loads approximate 224 m^3 (YESAA Project Proposal, page 6-31), or about one-third of the initial planned LNG storage volume of 666 m3 (four 166.5 m^3 horizontal tanks, YESAA Project Proposal, page 6-19).

the LNG tank supplier). At a rate of 0.25%, it would take more than 200 days for 50% of the LNG to boil off. Based on the assumed LNG fuel composition on delivery, if 50% of the methane and inert gases, i.e., nitrogen, were to boil off but not the ethane, then in the extreme, the composition of the remaining LNG would be 91% methane, 8% ethane and 1% other hydrocarbons (nitrogen will be one of the first components to boil off). As reviewed below, this change in stored LNG composition is not expected to create material issues related to safety or process considerations.

Yukon Energy will manage its inventory to limit the effects of boil off gas and meet its requirements on an ongoing basis. Note that boil off gas is not released. Aside from managing LNG deliveries in the context of expected thermal power generation requirements, Yukon Energy has several fuel uses year round that can beneficially consume the boil off gas to maintain the vapour space pressure below the PSV (pressure relief valves) set point (see YESAA Project Proposal, page 6-23).

Further considerations related to LNG aging, LNG density increase and natural gas fuel content per cubic metre increase are noted below:

1. **As LNG ages, the concentration of ethane plus increases and the density of the LNG increases -** LNG tanks are designed for a specific gravity (SG) of 0.47 (which is also a requirement of CSA Z276). As noted, the storage/ vapourization facility is assuming an LNG fuel composition that is not more than 4% ethane and ½% other hydrocarbons to start. Assuming half the LNG were to boil off as discussed above and the concentration remaining LNG was 91% methane, 8% ethane and 1% other hydrocarbons, calculation shows that the SG of this mixture would be 0.4455 at -158C, i.e., well within the tank design limits. The composition and specific gravity of the aging LNG will be monitored by YEC, but is not anticipated to be an issue that will be difficult to manage.

2. **If the LNG in the tank ages, it will increase in SG, which will have an effect on the performance of the LNG pumps, vaporizers and compressors** - these pieces of equipment will all continue to function, however, not at the flow rate that they would with lower SG LNG. This is anticipated to be acceptable, since full flow operation is not anticipated with heavily aged LNG.

3. **The Wobbie number and methane number of aged LNG will be higher-** however, it is not anticipated that aged LNG will be sent to the natural gas

burning engines. Rather, before the season of LNG power generation, fresh LNG will be delivered and blended with the small amount of aged LNG to give a mixture of LNG within specification range of the GE Jenbacher natural gas engines, which require a fuel with a minimum methane number of 80.

(c)

If there was an extended disruption of the supply of LNG beyond the storage capacity of the Project then the other backup diesel engines on the grid would be run until the supply of LNG was restored.

TOPIC:

REFERENCE: YEC Application – page 7:

"YEC also plans an RFP for preliminary design and potential fabrication for the A-Train trailer units in order to address the tight timelines for the Project and the objective to keep delivered LNG costs as low as possible."

PREAMBLE:

QUESTION:

a) Please fully explain all anticipated contractual arrangements and forecast contract amounts YEC expects to enter into for the transportation of LNG to the proposed storage facility in Whitehorse.

b) Please explain the strategy for purchasing fuel trailer units as opposed to other options considered by YEC.

ANSWER:

(a) and **(b)**

Please see response to YUB-YEC-1-5 and YUB-YEC-1-44**.**

TOPIC:

REFERENCE: YEC Application – page 8

PREAMBLE:

Yukon Energy has selected GE gas-fired generating units.

QUESTION:

a) Please fully explain the criteria as well as relative weightings used by YEC to evaluate its generation unit options.

b) Please provide a table that shows the ratings by criteria for each generation option evaluated by YEC.

c) Please fully explain why YEC chose the GE gas-fired generating units as the best solution for its needs.

ANSWER:

(a) through **(c)**

The business case for the GE engines compared to all other options, including new Wartsila dual fuel engines and life-extension of the Mirrlees, is reviewed in the Application and in YUB-YEC-1-13(a).

The process to investigate and evaluate specific gas generation unit options is reviewed in response to YUB-YEC-1-15, which also references YCS/LE-YEC-1-5.

TOPIC: **Diesel Generation Alternatives to the Project.**

REFERENCE: **Section 4.2.3**

PREAMBLE:

Footnote 35, page 26 YEC states that preliminary engineering was completed on two new 6.7 Wartsila dual fuel engines.

QUESTION:

a) Did YEC consider or provide preliminary engineering for new diesel only units? If so, what were the costs? If not, why not?

b) Were annual O&M costs considered in comparison between new natural gas-fired engines and new diesel units? If so, please provide. If not, why not?

ANSWER:

(a)

YEC, as part of the diesel balance of plant feasibility study, did complete preliminary engineering work for dual fuel or gas only generation unit options that in effect also addressed requirements for any new diesel option that would use the WD1 and WD2 service bays. The cost of this work was $291,000. Please see YCS/LE-YEC-1-5.

(b)

The non-fuel O&M costs used in the comparison were assumed to be the same at 1.5 cents per kWh for the new natural gas units and diesel units. Given the backup use of these engines the O&M costs are not significant in the overall business case compared to the capital costs and annual fuel costs. Given that all of the options considered were new reciprocating engines, using a different fuel such as natural gas versus diesel, the non-fuel O&M expense is not expected to be significantly different as between the new diesel and new gas alternatives.

TOPIC:

REFERENCE: Estimated Capital Costs for Project

PREAMBLE:

QUESTION:

a) Many costs are assumed or forecast in the Application. Please provide any updates YEC has obtained that would support additional forecast accuracy.

b) Please provide a breakdown, similar to table 3-1, of costs that are required to replace WD1 and WD2 with new diesel only engines.

c) What costs have been incurred to date on the LNG project? How is YEC proposing to treat these costs if the project does not move forward to completion?

ANSWER:

(a)

Please see response to YUB-YEC-1-1(d).

(b)

Table 1 below presents the updated cost estimate to replace the existing WD1 and WD2 Mirrlees units with two 6.7 MW engines. Cost includes building and auxiliary upgrades required with the inside Whitehorse Diesel Plant option. The updated cost estimate is $32.7 million, or $0.8 million lower than in the Application, reflecting removal of planning costs specific to LNG supply and transportation and therefore not relevant to a diesel only option.

Table 1:
Estimated Capital Costs for Diesel Engine Replacement at WTGS (2013 $Millions)

Activity	Estimated Costs ($million)	% Total Costs
Planning Costs	1.6	5%
Engineering Services	2.7	8%
Project Management	1.6	5%
Diesel Gen - Engines	15.9	49%
Grid Connection	0.8	2%
Owners Costs - Construction Phase	3.5	11%
BOP - Preliminary Assessment	0.3	1%
Balance of Plant work	6.3	19%
Total	32.7	100%

(c)

For incurred costs to date, please see response to YCS-LE-YEC-1-11.

The treatment of these and other sunk costs in the event "the project does not move forward" would depend on the circumstances. As with all costs, YEC would seek recovery from ratepayers for all prudently incurred costs at the next General Rate Application. Please see response to YUB-YEC-1-2.

TOPIC:

REFERENCE: Retirement of WD1 and WD2

PREAMBLE:

QUESTION:

a) For WD1 and WD2, when was the last major rebuild or life extension completed project completed, what were the costs incurred and how were they incorporated into YEC's 2012-2013 approved Revenue Requirement?

b) What are the operating hours (lifetime) of each unit?

c) What were the operational hours for the units in each year 2010 – 2013?

d) What are the forecast operating hours for each unit up to retirement dates?

ANSWER:

(a)

The last major life extension work completed on both WD1 and WD2 occurred in 1999.

(b)

Table 1 below presents operating hours of WD1 and WD2 at the end of 2013.

Table 1:
Operating hours for
WD1 and WD2 (end of 2013)

Unit	Hours
WD1	41,804.80
WD2	38,202.00

(c)

The table below presents operational hours of WD1 and WD2 for the period between 2010 and 2013.

Table 2:
Operating Hours for WD1 and WD2: 2010-2013

Diesel Unit	Operational Hours				
	2010	2011	2012	2013	Total
WD1	0.00	79.00	14.80	14.50	108.30
WD2	3.20	47.60	13.00	13.50	77.30

(d)

WD1 and WD2 are expected to run for an additional 20 hours each between now and the retirement date. Both engines are dispatched after the EMD and CAT engines for meeting peak. WD1 and WD2 would be used in situations where other more efficient diesel engines would fail to meet peak, should the Yukon experience drought conditions or to meet to meet emergency back-up requirements (e.g., N-1 event).

TOPIC: **Generation engine efficiency**

REFERENCE:

PREAMBLE:

QUESTION:

a) Please provide the base load and part load efficiency curve for the selected generating units.

b) Please provide the base load generation engine efficiency on a Lower Heating Value (LHV) basis and a Higher Heating Value (HHV) basis.

c) Please provide the expected HHV/LHV ratio of the fuel.

d) Please confirm that the projected fuel savings for the project are based on an HHV basis (i.e. the basis that fuel is purchased from a supplier rather than the LHV basis of engine performance characteristics provided by the equipment manufacturer. If not confirmed, why not?

ANSWER:

(a)

Part load efficiency curves for GE engines were calculated using information provided by manufacturers and assume 0% tolerance.

Table 1:
Calculated Part Load Electrical Efficiency
for New GE Jenbacher Engines

Load	Electrical Efficiency
100%	44%
75%	43%
50%	40%

(b)

The LHV efficiency is provided above in response a. HHV engine efficiency is expected to be 12% lower than the LHV efficiency. As such, the 44% efficiency at 100% load would decrease to 39%.

(c)

Shell has not provided an HHV/LHV ratio for the fuel to be produced at their facility; however, based on fuel specification obtained from other LNG producers, the ratio is expected to be close to 1.12.

(d)

Projected fuel savings for the project were based on HHV basis.

TOPIC: **New Modular Natural Gas-fired Generation units**

REFERENCE:

PREAMBLE:

On page 7 of the Application it is stated 'new natural gas-fired engines are assumed to have an economic life of 40 years'

QUESTION:

a) Is the economic life based on information from manufacturer, an industry standard or based on operating hours of the unit in that timeframe?

b) What are the maintenance intervals for the new natural gas-fired engines?

c) Does YEC currently have staff or employees that can complete work for the required maintenance of the new natural gas-fired engines? If yes, please fully explain. If no, please fully explain.

d) What external resources will be needed to complete regular work and maintenance on the new natural gas-fired engines natural gas units?

e) Please provide a life cycle cost analysis of the total expenditures for the Project over the future expected life of the facility considering capital and future operating expenditures. Please provide a comparison to a new diesel generation alternative.

ANSWER:

(a)

This estimate is based on discussions with suppliers, industry experts and YEC knowledge of reciprocating engine technologies. Please see also response to YUB-YEC-1-52(a).

(b)

Attachment 1 to this response provides the maintenance schedule for the new natural gas-fired engines as recommended by the manufacturer.

(c)

YEC staff will be trained by the engine manufacturer on operation and maintenance of the engines during commissioning. In addition, YEC will work with the engine manufacturer to complete routine maintenance until YEC staff takes over. Major overhauls will be completed in collaboration with the engine manufacturer or its representative.

(d)

Please see response to part (c) above.

(e)

Please see response to YUB-YEC-1-45(f) and (h).

TOPIC: **Forecast diesel generation**

REFERENCE:

PREAMBLE:

QUESTION:

a) Table 4-1 indicates forecast Default Diesel Generation for 2013, please provide actual diesel generation for 2013.

ANSWER:

(a)

Diesel requirements in Table 4-1 were estimated based on forecast load for 2013, and long-term average hydro and wind generation. The preliminary actual diesel generation net of diesel charged to capital and RFID is 1.1 GW.h.

TOPIC: **First Nation Partnership Agreements**

REFERENCE:

PREAMBLE:

QUESTION:

a) Please provide an update on First Nations Partnership Agreements in relation to the Project.

b) What are the Project implications if a First Nations Partnership Agreement is not completed?

ANSWER:

(a) and **(b)**

Please see response to YUB-YEC-1-18(c) and (d). It is expected that an agreement with KDFN will be completed in the near future.

In the event that an agreement is not completed, there will be no First Nation investment in the Project and the implication would be that the Project would be fully financed by YEC.

As a separate matter, YEC is proceeding to engage with KDFN and TKC regarding a Benefit Agreement to meet the requirements of Yukon Asset Construction Agreement provisions (specifically with KDFN) and Yukon Oil & Gas Act (YOGA) section 68 provisions with both KDFN and TKC.

Yukon Utilities Board
(YUB)

TOPIC: **YESAB Screening**

REFERENCE: **YEC LNG Project Application (Application), page 12**

The schedule anticipates completion of the YESAB review, Part 3 YUB review, and Decision Body Approvals, and securing all needed permits and approvals required to commence construction of the Project by May 1, 2014.

- The YESAB Executive Committee assessment process includes, at a minimum, the following major steps:
  - A pre-screening adequacy review…
  - Screening with Public Comment …
  - Release of draft screening report – February 1, 2014 is targeted for issuance of the draft screening report …
  - Public comment on the Draft Screening Report and release of the final report recommendations… YEC's schedule assumes review and comment on the YESAB Draft Screening Report will be complete within 30 days of its release, with Final YESAB Recommendations provided within 60 days of the YESAB's release of its Draft Screening Report, i.e., by April 1, 2014.
  - YEC's schedule assumes approval of the YESAB Recommendations by all Decision Bodies (i.e., the Yukon Government) within 15-20 days following release of YESAB's Recommendations.

PREAMBLE:

The Board requires further information.

QUESTION:

a) Given the relatively short construction season in Yukon and the regulatory processes that are necessary in order that YEC obtain the required permits and approvals for the project to proceed, does YEC have contingency plans in place in case the necessary approvals are not issued by May 1, 2014 and it is unable to commence construction on this date? Please explain what these plans are.

b) Please provide an update with regard to the expected release date of YESAB's draft screening report.

c) Please provide updated release dates of (i) the YESAB Final Recommendations report, and (ii) expected "approval of the YESAB recommendations by all Decision Bodies (i.e. the Yukon Government.)"

d) Considering that the LNG project costs "…are preliminary estimates developed in mid-2013 based on preliminary quotes and engineering,"[1] can YEC provide any updates to its project costs and is YEC anticipating any additional costs for mitigation measures that may result from the YESAB review that is currently underway? If no updates to the project costs are available, can YEC provide what order of magnitude of additional costs may result from further engineering or the YEASAB review?

ANSWER:

(a)

YEC's plans are focused on being able to launch initial civil works on site as soon as the necessary approvals are in place in May 2014 (assuming today that the earliest start date is likely to be mid-May rather than May 1), followed by construction plan options that will facilitate receipt of the gas engine modules when they arrive on site in July and receipt of LNG tanks and the vaporizer skid when they arrive on site in September. As events unfold, YEC will assess updated schedules to determine at what point construction activities and/or commissioning of the equipment will not be feasible to conclude prior to calendar year end and the point at which in-service would need to be deferred until spring or summer 2015.

(b) and **(c)**

On February 4, 2014 YESAB informed YEC that the Executive Committee has determined that the supplementary information response is adequate and that sufficient information has been provided to enable them to prepare the draft screening report (DSR). YEC currently expects the DSR to be released as soon as feasible before mid-

[1] Application, page 8.

March, the YESAB Final Recommendation Report to be released on or before the end of April and the expected approval of the YESAB recommendations by the Yukon Government within two to three weeks thereafter.

(d)

YEC has prepared Project capital cost updates in late January 2014 for installing the initial two engines (8.8 MW) and other Project activities (excluding only the third engine) as set out in Table 1 below based on the current regulatory review process, final site configuration (i.e., no lease of the White Pass lands), contractual costs for selected key long lead equipment (two GE engines [Gas Drive], three LNG storage tanks [499.5 m^3 total capacity], skid mounted vaporization and related equipment, and transformer), updated site layout design, and contractual costs for Project Management and Project Engineering. Contingencies of $1.45 million are included in the update, with $1 million for construction contracts (primarily for the untendered civil, mechanical and electrical contracts estimates at $6.8 million as part of Site Development costs) and the balance for Engineering, Project Management and Owners as noted in Table 1.

Further details regarding updates shown in Table 1 in each major cost item are provided below:

- **Construction Contracts:**
  - $3.5 million more than the May 2013 estimate, with $1.0 million contingency for contracts not yet awarded.
  - The increase is focused in LNG Plant and Equipment and Site Development, and reflects EPC tender outcomes: limited response with proposed costs per the tender more than $4 million over budget:
    - LNG storage tanks cost at $1,291,125 (Taylor Wharton) plus estimate of $660,000 for transport from China, and $195,113 for US$ exchange on tanks and freight.
    - GP Strategies costs for LNG equipment supply at $4,250,000.
    - Balance of LNG plant costs ($400,000) for LNG equipment install and other related works.
    - The latest Site Development detailed construction cost estimate of $6,777,000 includes approximately $0.6 million provision for vapour barrier wall, access gates and $0.2 million for site power and communications equipment and cabling.

- Engine costs remain within original budget including contingencies; YEC and Gas Drive have reviewed and finalized costs for specific add-ons totaling $0.279 million over and above the contract price of $10.450 million.
- Grid connection costs are less than the original budget, reflecting coordinated design and costing review during January 2014.

- **Engineering & Management:**
  - $0.9 million greater than May 2013 estimate, with $0.2 million contingency (increase focused in Project Management, with some increases as well in engineering).
  - Higher Project Management costs reflect complexity of contracting and construction arrangements on the smaller site and the tight schedule.
  - Detailed Engineering remains within original budget estimate.

- **Owners Costs:**
  - $1.2 million less than May estimate, with $0.25 million construction support/contingencies (savings focused in AFUDC, land acquisition, contracting legal support, YEC labour and construction support/contingencies; increase for insurance which was not in May estimate).

- **Planning & Permitting:**
  - $0.2 million less than May estimate (reflects review of specific cost items, including removal of approximately $1.0 million of costs as not being within the Project scope).
  - Updated costs reflect increased permitting and regulatory costs for new scope for YESAB Executive Committee review (rather than Designated Office review assumed in May 2013), and revision to YESAB filing in November 2013 when YEC could not secure WP&Y lease.
  - Updated costs reflect $1.0 million of removed costs for the following:
    - supply and transportation (removal of $0.25 million of Fort Nelson supply-cost investigations not related to the Project);
    - preliminary engineering (removal of $0.29 million of preliminary engineering related to diesel plant that was not related to the Project);

- permitting & regulatory (removal of $0.1 million of Life Cycle Assessments costs that not required for regulatory review of the Project); and
- Part 3 Application and related YUB Hearing (removal of $0.4 million projected costs based on these costs being charged to YEC Regulatory Hearing costs for recovery from ratepayers [subject to YUB review]).

- **Demolition:**
  - $0.9 MM less than May 2013 estimate (decrease reflects $0.5 million that was included in error; balance of reduction is costs not needed for demolition per se and would be assigned to redevelopment of the space for future use when this occurs or reflect current assumption that recoveries from disposal of Mirrlees parts will offset offsite transport disposal costs).
  - In the short term, future thermal units will likely occur first on the trapezoid site with addition of more natural gas fired units.

YEC is currently not anticipating any additional costs for mitigation measures that may result from the YESAB review currently underway.

Table 1: Updated Project Capital Cost Estimate: Initial Two Engines[1] ($millions)

Item	May 2013 Estimate	January 2014 Update
Construction Contracts		
LNG Plant - Equipment	4.57	6.75
LNG Gen-Engines	11.44	10.95
LNG - Site Development	5.46	6.78
Grid Connection	2.53	2.03
Contingencies	-	1.00
Sub-Total	24.00	27.50
Engineering & Management		
Preliminary Engineering	0.13	0.19
Detailed Engineering	1.38	1.24
Project Management	1.03	1.85
Contingencies	-	0.20
Sub-total	2.54	3.48
Owners Costs		
Land Acquisition	0.59	0.20
Steering Committee, Legal, Insurance	1.00	0.80
YEC Commissioning & Start-up	0.12	0.12
YEC Labour	0.89	0.62
AFUDC	1.00	0.45
Const. Support/Contingencies	0.06	0.25
Sub-total	3.67	2.43
Planning & Permitting		
Supply & Transportation	0.58	0.41
Preliminary Engineering	0.67	0.32
Permitting & Regulatory	0.89	0.78
Part 3 Application	-	-
Proj. Manage. & Owners Costs	0.58	0.99
Sub-total	2.71	2.51
Demolition	1.45	0.55
Total - All Costs	**34.36**	**36.48**

Note 1: The Project includes three engines (13.1 MW). The timing to install the third engine (4.4 MW) is forecast to be in 2016 at an estimated cost of $4.4 million.

TOPIC: **Regulatory and schedule risks**

REFERENCE: **Application, page 39**

Regulatory/Schedule risks — Exist to the extent that permits and approvals are not available, or weather conditions are not favourable, to allow construction activities to commence as planned starting May 1, 2014. Delay of Project construction beyond May 1, 2014 threatens the ability to complete Project construction in the 2014 summer construction season and the ability to have the Project in service before the end of Q4 2014 in order to be available to displace diesel requirements in the winter of 2014/2015. Delay of Project in service also increases the risk of YEC incurring added capital costs. Not having the Project in service by the end of 2014 means that the Project will not be in place to reduce ratepayer fuel costs in the first half of 2015 by approximately $2.1 million and that new thermal generation capacity for reliable service will also not be available as required during that winter.

PREAMBLE:

The Board needs further information.

QUESTION:

a) What, if any, are the financial impacts to YEC or its customers beyond the lost $2.1 million ratepayer savings, if there are delays of six months or one year with respect to having the LNG project in service prior to the end of Q4 2014?

b) Please provide detailed cost/benefit analyses assuming (i) a six-month delay and (ii) a one-year delay with respect to the estimated end of Q4 2014 project start-up date. Please provide explanations related to additional maintenance costs that may arise. Please provide calculations in an Excel spreadsheet with all formula intact. Please include additional maintenance costs (beyond normal O&M costs) to allow the existing diesel generators to operate.

c) Please provide detailed sunk costs to YEC if the project does not proceed.

d) Does YEC anticipate any delays with respect to the delivery of long-lead equipment orders at this time?

ANSWER:

(a) and **(b)**

Financial impacts to YEC or its customers, beyond the lost ratepayer savings estimated in the Application, if there are delays of six months or one year with respect to having the Project in service prior to the end of Q4 2014 will vary considerably depending on the specific circumstances associated with such delays.

For example, a six month delay in being able to commence site construction would result in delay of all major site work until spring 2015 and an overall delay of a full year in having the Project in service. Costs of this delay have not been estimated, and would include penalties and/or added costs for dealing with equipment commitments for delivery during summer 2014 as well as added costs for all contracts concluded based on the current schedule. These costs would have to be negotiated with each supplier and contractor. YEC and ratepayers would also be subject to added risks related to retaining WD1 and WD2 for an added year of service. No specific added maintenance costs have been identified beyond normal O&M to address this specific concern as there is no useful "short-term" maintenance that could be performed on these two engines that would provide any meaningful increase in their reliability. WD1 and WD2 are now in their 46^{th} year of un-interrupted service.

In contrast, many of the above delay costs would be avoided if the basic construction work is completed roughly on schedule during 2014 (such that no major issues related to receipt of major equipment delivered to site), but full commissioning of the units is delayed sufficiently that a decision is made to defer completion of this work until after winter has concluded. One specific cost impact in this scenario would be an increase in Project AFUDC costs of approximately $50k per month of delay.

A "six month" delay cost estimate might be anywhere between the above extremes and, depending on the circumstances, might potentially also involve added cost issues.

Although YEC cannot develop specific cost estimates for such delays, in the event of material delays YEC would work to mitigate costs related to any such delay to the extent feasible.

The cost/benefit sensitivities provided in Table 4-4 in Section 4.3 of the Application cover potential capital cost increases of up to 20% that are within the extreme ranges reviewed above. YEC is not able to provide a more detailed cost-benefit analysis on this matter.

(c)

In the event the Project was not approved to proceed, and assuming an end of April 2014 decision date to this effect, the estimated sunk costs are as outlined in Table 1 below:

Table 1:
Estimated Sunk Costs

	Estimated Costs ($ Million)			
Project Component	**Costs Incurred to Jan 2014**	**Feb-Apr 2014 (estimate)**	**Failure to proceed costs (estimate)**	**Estimated Sunk Costs**
LNG Gen - Engines	8.6	0.6	1.8	10.9
LNG Storage - EPC Contract	0.0	2.4	0.2	2.6
Grid Connection	-	0.1	0.1	0.2
Abandoned Equipment Costs				**13.8**
Engineering Services	0.6	0.5	0.1	1.2
Project Management	0.4	0.3	0.1	0.8
Professional Services				**2.0**
Planning Costs	2.2	0.2	0.1	2.5
Owners Costs	0.4	0.3	0.5	1.2
BOP - Preliminary Assessment	0.3	-	-	0.3
Owners Costs				**4.0**
Total	**12.5**	**4.5**	**2.8**	**19.8**

In regards to the Gas Drive contract for the generation modules, YEC would fulfill all terms relevant to the Gas Drive contract. Cancellation of the contract would likely result in additional costs to hold and store the units at an appropriate point in transit until terms were established with an alternate purchaser. Recoveries from sale of the units would be

offset by storage costs for the period the units sit in abeyance while alternate delivery location and terms are arranged. Ultimately, YEC would expect to recover a major portion of the $10.9 million spent, but it is not feasible to estimate the net receipts or duration of a cancellation process.

For the LNG storage tanks and equipment, estimated costs to April 2014 are the contract deposit and design process installments. Some additional materials costs may apply for the tanks and equipment already being manufactured but factory terms are that unaltered materials may be returned to inventory for a credit. Negotiations to effect cancellation of these orders would attempt to limit costs to be equal to the actual costs incurred by the vendor.

In regard to engineering and project management services YEC has the ability to terminate these contracts with 5 business days notice whereupon damages are limited to payment for services up to the termination date.

(d)

YEC does not anticipate any delays with respect to the delivery of long-lead equipment orders, each of which has been concluded at this time.

TOPIC: **Engineering design and permitting**

REFERENCE: **Application, page 4**

The precise location of each component of the Project will be finalized upon completion of detailed engineering design and permitting by regulators following assessment under the Yukon Environmental and Socio-economic Assessment Act ("YESAA").

PREAMBLE:

The Board requires further information.

QUESTION:

a) When will detailed engineering design be completed? Please explain what detailed engineering design entails.

b) Please provide YEC's expectation as to the length of time it will take to receive the required permits once the YESAA final assessment has been completed.

ANSWER:

(a)

Detailed engineering design is being completed as required to prepare tender documents (including but not limited to issued-for-tender drawings, specifications, equipment lists, material and equipment quantity estimates) for the civil, structural, mechanical and electrical construction tenders that are scheduled for issue at varying times over the period from March to late April. Detailed engineering for specific long lead equipment not yet ordered is also being completed as required to meet shop fabrication and delivery dates to site.

(b)

As with prior major project YESAB Executive Committee reviews that YEC has been involved with, YEC is working to secure required permits needed to start construction at

basically the same time as the Decision Document approval is provided of the YESAB Final Recommendation (i.e., within 2 to 3 weeks after the YESAB Final Screening Report is released).

TOPIC: **LNG supply**

REFERENCE: **Application, page 2, page 10, page 11 and page 13**

Yukon Energy has secured an LNG supply of up to 250 m3 per day for a minimum of five years from Shell Canada's Jumping Pound LNG plant being developed near Calgary and scheduled to start operation before the end of 2014. Yukon Energy also retains the potential during the term of the Shell Canada contract to source LNG from the Fort Nelson area in northern British Columbia should additional liquefaction facilities come into service in this area, and/or Shell Canada arranges to make LNG supplies available in this area.

Yukon Energy has secured a minimum five-year (starting from date of first delivery) flexible LNG supply of up to 110,750 kg per day (approximately 250 m3 per day) from Shell Canada's Jumping Pound production facility being developed near Calgary, which is planned to start operation before the end of 2014 with an estimated capacity of 250,000 metric tonnes per year (i.e., more than 1,500 m3 per day). LNG costs to Yukon Energy under the contract with Shell Canada will fluctuate each month to reflect the latest published monthly Alberta Energy Company (AECO) index price of natural gas as reported by the Natural Gas Exchange.

With development of more efficient operations with larger and more stable loads, the estimated A-Train delivery cost from Calgary is estimated to fall to 3.7 cents/kWh and from the much closer Fort Nelson area (978 km) the estimated cost would fall to 1.6 cents/kWh. The initial tractors for the LNG haul are assumed to be diesel-fueled engines. To secure lower costs and emissions, ongoing efforts will occur to secure LNG-fueled tractors as soon as they are available commercially in Canada.

Yukon Energy is assessing opportunities for coordinating LNG shipping activity with NT Energy and other active and potential northern users of LNG, and YEC also plans an RFP for preliminary design and potential fabrication for the A-Train trailer units in order to address the tight timelines for the Project and the objective to keep delivered LNG costs as low as possible.

PREAMBLE:

The Board requires further information.

QUESTION:

a) Has there been any change to the scheduled start-up date of Shell Canada's Jumping Pound LNG plant? If yes, what is the new date?

b) If YEC's LNG project has been commissioned for use, are there contingencies in place to address delays respecting Shell Canada's Jumping Pound LNG plant's scheduled start-up date?

c) Besides Western Copper & Gold, has YEC identified other possible users of LNG that may be able to partner with YEC to help reduce LNG supply chain costs?

d) Please provide further information respecting "development of more efficient operations".

e) What is the likelihood of a Fort Nelson area facility being developed? Within what timeframe?

f) In terms of the price for LNG, YEC stated its contract with Shell prices the commodity based on the AECO index. How is the price on the AECO index adjusted to determine a price based at the Calgary facility?

g) Would there be a different adjustment to the prices for product acquired in Fort Nelson? Please explain.

ANSWER:

(a) and **(b)**

In response to ongoing uncertainties regarding the start-up of Shell Canada's Jumping Pound LNG plant, Yukon Energy has been finalizing arrangements with NT Energy for initial LNG supply to Whitehorse as required for commissioning the Project in Q4 2014 and for gas generation requirements in winter 2014/2015. As reviewed below, these

arrangements will utilize NT Energy's Tridem units until such time as A-Train units are permitted and available for YEC use to the selected source of LNG supply, and will secure LNG supply from FortisBC at Tilbury (Delta BC) until such time as a lower cost source of LNG is available to YEC.

As background, NT Energy is currently sourcing LNG from FortisBC's Tilbury facility, and hauling this LNG, using Tridem units with a net payload of approximately 64.5 m^3 per unit, from Delta BC to Inuvik via Yukon and the Dempster Highway. NT Energy target LNG load for power generation at Inuvik on average approximates 250,000 GJ/year or 28 m^3/day, with load requirements reasonably steady through the year but with the Dempster access closed for about two months each year due to river access seasonal closures for the month of May and for a month during the November to December period. By the fall of 2014, NT Energy expects to have four Tridem units engaged in this activity (there are currently two Tridem units in operation during the initial start up phase).

In the past month, YEC has been working with NT Energy on contingency plans to address possible delays respecting Shell's Jumping Pound LNG plant and/or in securing A-Train unit permitting in all required jurisdictions. More specifically, YEC has been examining plans, if required, to utilize NT Energy Tridems during the November 2014 Dempster closure period to supply LNG to Whitehorse (from Fortis at Tilbury, if needed) for Project commissioning (e.g., about 7.7 Tridem trips would be needed for the initial fill of the Project's three LNG storage tanks) and for initial 2014/15 winter operation of the Project. YEC is also exploring with NT Energy possible additional LNG access for YEC if needed in the following months using NT Energy's established LNG supply chain. These contingency measures are considered appropriate for the next year given that YEC's actual thermal generation requirements at Whitehorse for the 2014/15 winter period are forecast to remain well below long-term average requirements, due to recent high inflows and ample water storage in YEC reservoirs. As regards LNG supply other than Shell's Jumping Pound LNG plant, YEC's contingency plans also take into account the new Fortis LNG dispensing Rate Schedule 46 approved by the BCUC in December 2013, pursuant to BC Government OIC 557-13 (which sets tariffs for access to Fortis LNG supply at Tilbury), as well FortisBC's available LNG capacity today available for dispensing of about 6,000 GJ/day (about 250 m^3/day) plus its approved plans to expand this capacity in mid-2016 by 30,000 to 60,000 GJ/day.

Overall, using Rate Schedule 46 "Spot" contract energy from FortisBC and NT Energy's scale of Tridem units to haul LNG from Tilbury to Whitehorse, YEC estimates that costs to secure and deliver LNG to Whitehorse would be about $1.46/MMBtu more expensive (at any given gas price) than the updated costs estimated for supply from a Shell Jumping Pound plant using A-Train units - and, if A-Trains were to be approved for this route, Fortis Spot LNG supply would be slightly less costly than YEC's estimated cost for supply from Shell. For example, assuming an AECO index gas price of $4.50/MMBtu and gas conversion efficiency at 40% (as per the Application), the following comparative delivered LNG costs estimates are provided[1]:

- Delivered cost estimate from Fortis Tilbury (Spot contract):
  - Using Tridem units (64.5 m^3 per unit net payload), estimated cost of $17.58/MMBtu [$15.0 c/kW.h]; and
  - Using A-Train units (95.3 m^3 per unit net payload), estimated cost of $16.30/MMBtu [$13.9 c/kW.h].

- Updated delivered cost estimate from Jumping Pound (if in operation with YEC's Shell contract):
  - Using Tridem units (64.5 m^3 per unit net payload), estimated cost of $17.99/MMBtu [$15.3 c/kW.h]; and
  - Using A-Train units (95.3m^3 per unit net payload), estimated cost of $16.51/MMBtu [14.1c/kW.h].

Yukon Energy is also continuing to work with NT Energy to examine other potential LNG supply options for late 2014 and beyond, including LNG supply from the Encana/Ferus plant expected to open at Grand Prairie, Alberta in the next few months and ongoing proposals to develop small scale (2014/2015) or larger scale LNG liquefaction plants (2016 and later) in northern Alberta (Edmonton) or northern BC (Dawson Creek or Fort Nelson).

[1] See YUB-YEC-1-44 for updated LNG haul costs to Whitehorse for A-Train and Tridem units from Calgary, Vancouver and Fort Nelson LNG supply sources. A-Train costs include 10% allowance for initial low utilization, and Tridem units from non-Vancouver locations include 5% allowance for initial low utilization. Tridem units from Vancouver are assumed to be NT Energy's units and therefore no allowance is included for initial low utilization.

(c)

As noted above, YEC is working with NT Energy as well as Western Copper & Gold to help reduce LNG supply chain costs, and in the course of ongoing discussions has also identified other potential northern users of LNG, including potential LNG use for summer power generation at Skagway Alaska (cruise ship requirements) and the Yukon Zinc Wolverine mine site.

(d)

The phrase "development of more efficient operations with larger and more stable loads" was provided in the context of reviewing A-Train and Tridem LNG haul unit economics. It addresses the expected reduction in average unit haul costs (related mainly to the fixed annual costs for the much larger A-Train units) as haul loads increase and become more stable and thereby increase average utilization of these units. The analysis assumes that any haul cost arrangement will in effect pass on to YEC the annual fixed costs for these units (in that the units would be obtained specifically for the YEC haul requirements), such that YEC will secure lower average costs per haul from higher use of this equipment.

(e)

Small scale (e.g., about 15,000 USG/day units, or about 60 m^3/day) plant options are being examined by at least one supplier for potential development in the 2014/2015 time period in the Fort Nelson/Dawson Creek area.

Development of larger facilities (e.g., 100,000 USG/day or larger) at Fort Nelson would be likely to occur at such time as reasonably stable load opportunities sufficient to sustain this scale of LNG plant operation emerge in Yukon, NWT and other northern areas that can be efficiently served from Fort Nelson. By way of example a large scale Fort Nelson area LNG facility is expected to be developed as a key component of the Western Copper & Gold development of the Casino Mine Project (Western Copper & Gold recently filed a Project Proposal with YESAB, and is currently planning to start construction in 2016 for operation by about late 2018, with material power requirements starting in 2017). Potential LNG suppliers could provide such larger facilities by mid to late 2016 if loads were sufficient at that time.

(f) and **(g)**

The contract with Shell does not adjust the AECO index based on the Calgary location. It is expected that an LNG plant located at Fort Nelson would have a reduction from the AECO index price to reflect the plant's location (a reduction of approximately 40 cents/GJ has been assumed in assessments of LNG supply from Fort Nelson).

TOPIC: **LNG Transport**

REFERENCE: **Application, page 10**

Significant travel distances and the comparatively low density of LNG (approximately 60% of diesel fuel) emphasize the importance of having the most economical type of transportation possible while maintaining rigorous safety standards. Yukon Energy and Western Copper & Gold contracted PROLOG Canada to work with tractor trailer manufacturers to design a double trailer (A-Train) combination with a 95,000 litre capacity as an alternative to the Tridem units with a 54,000 litre capacity that are currently used to transport fuel into Yukon. The A-Train has been approved for use in Yukon for supply to Whitehorse along the Alaska Highway, but has yet to be approved for use in Alberta or British Columbia.

PREAMBLE:

The Board requires further information.

QUESTION:

a) Respecting the contract that Yukon Energy and Western Copper & Gold entered into with PROLOG Canada toward designing a double trailer, please provide:
   i. any contract related costs that YEC has incurred and will be incurring into the future; and
   ii. the terms of reference for the contract.

b) Are the costs referenced in part (a) included in the estimated LNG project capital costs shown in Table 3-1 of the Application? If not, why not?

c) Who is responsible for the costs of the RFP for the preliminary design and potential fabrication of the A-Train trailer units? Are any of these costs included in the LNG project cost/benefit analysis?

d) Please explain how the coordination of LNG shipping with others would work? Would other users have access to the YEC unloading facility? Storage? Vapourization unit?

e) Considering the displacement assessment shown in Appendix D of the Application, if the LNG project is approved and the LNG units are commissioned and in use, approximately how many trips per month are required by the A-Train scenario and the Tridem units scenario to assure adequate supply of LNG to provide the generation (GW.h/year) shown?

f) In the event of an Alaska Highway closure are there contingencies in place that allow procurement of LNG from alternative sources? If yes, please explain what these contingencies are. If no, please explain.

g) Please provide an update respecting the expected timeframe when the A-Train units will be available (fabricated and licensed) to transport LNG fuels.

h) Please explain how an A-Train unit that has not been designed or fabricated has been approved for use in Yukon along the Alaska Highway? When was that approval obtained?

i) Please describe the regulatory process and timeframe to get A-Train approval for use in Alberta and B.C.

j) Will YEC own the A-Trains?

k) If the answer to (j) is not affirmative, please describe the lease agreement and terms regarding the A-Trains.

l) Please provide copies of the transportation agreements for both the A-Trains and the Tridem units.

ANSWER:

(a)

Yukon Energy retained PROLOG to provide cost analysis for LNG truck haul, and to assist design and permitting of the A-Train trailer. Costs of $32,450 have been incurred to date by YEC with regard to PROLOG Canada toward designing a double trailer (A-Train) to the extent required for permitting. The basic design that was provided for permitting was used to secure approvals in Yukon, and to provide information needed for seeking permitting in Alberta and BC. Provision is included in the Planning & Permitting budgets in 2014 for an additional $30,000 for assistance as required for completing a truck haul RFP and for haul cost analysis.

(b)

The above noted costs ($32,450 to date and $30,000 for 2014) are included in Table 1.1(d) under Planning & Permitting (Supply & Transportation).

(c), (g), (j), (k), and **(l)**

In order to protect schedule and development of the A-Train, Yukon Energy has decided to arrange preliminary design and potential fabrication of the A-Train trailer units. Projected costs for this activity are included under Planning & Permitting “Supply and Transportation” costs in the updated Project capital costs as set out in YUB-YEC-1-1(d).

Based on qualifications and stated interest, it has been decided to proceed with CVA as the contractor for this work, subject to concluding acceptable contract terms whereby CVA will complete over 10 to 14 weeks the required shop drawings with the cost for this work (less than $60,000 $US) to be included in the final cost for the initial unit(s) that YEC thereafter orders within a defined time period at an agreed upon price and time period (approximately five months) for fabrication and delivery. These timelines enable YEC to potentially be able to utilize A-Train units when the Project begins commercial operation at the end of 2014, if so desired and if permitting is secured six months prior to commercial in-service of the Project (so as to enable YEC to give notice for CVA to proceed with fabrication). However, YEC only expects to proceed with fabrication if it is satisfied that the units are being permitted as required for the specific LNG supply options that YEC is to rely upon.

YEC will examine potential options for ownership of A-Train units to be used by YEC, including ownership by the selected LNG transport service contractor, or ownership by YEC, to determine what yields best value to YEC. In the end, YEC will likely be responsible for the fixed annual costs (depreciation and annual capital costs) for the units (either directly through YEC ownership, or through contract charges with the LNG transport service contractor) as the units will be designed and committed to meet YEC requirements on a first priority basis. If fully utilized throughout the year, the units are expected to have an economic life of five years (this would likely be extended accordingly to the extent that units were underutilized during any year).

No transportation agreements are currently available for either the A-Trains or the Tridem units. NT Energy has contracted with Ventures West for LNG transport to Inuvik with provision for Ventures West to own the Tridem units, as designed and fabricated by CVA, that are required for this transportation contract.

(d)

Options being examined to coordinate LNG shipping with NT Energy include:

- A contingency plan to address potential delays at Shell - this plan assumed initial LNG shipping for YEC during commissioning and winter 2014/15 utilizing NT Energy's Tridem units whereby these units would simply deliver LNG to the YEC site (either as full unit loads when Dempster route access to Inuvik is closed, or as partial unit loads when required at other times). As reviewed in YUB-YEC-1-4(b), this specific arrangement is suited to YEC's expected initial loads in the event (as is now the case) that this contingency plan is needed.

- At such time as A-Trains are permitted and available to YEC, these units could be used, for both YEC and NT Energy LNG supplies, to carry out the LNG haul to Whitehorse from southern Canada (Calgary or Vancouver) or Fort Nelson at greatly reduced cost compared to reliance on Tridem units. NT Energy would then use its Tridem units to haul LNG from Whitehorse to Inuvik (i.e., the LNG would be loaded to these units from LNG storage tanks at YEC's site).

YEC could consider other coordination LNG shipping options where LNG is made available to others during periods when YEC does not require the product, e.g., summer season loads at Skagway for cruise ship power requirements, or other users willing to

work out contingency or interruptible arrangements. Such options may or may not involve access to LNG storage at YEC's Project site; in either event, these options would improve utilization of A-Train units otherwise dedicated to YEC use.

At this time YEC has not considered options where others could have access to YEC's vapourization unit.

Any coordination option considered by YEC would retain full reservation of units as required to meet YEC requirements on a first priority basis.

(e)

LNG trips required for YEC will vary depending on grid thermal generation requirements, and these can vary greatly by year and season.

By way of example, the following estimated LNG trips per week for YEC are noted based on the updated grid load forecasts for 2015 provided in Appendix C of the Application:

- Under the Base Case grid load forecast without Alexco, LNG generation over the full year (2015) is estimated at 17.0 GW.h under long-term average (LTA) hydro generation, requiring on average 18.30 m^3/day of LNG:
    - Averaged over the full year, this LTA requirement would approximate 1.34 trips per week with A-Train units (95.3 m^3/unit) and 1.99 trips per week with Tridem units (64.5 m^3/unit); however, on LTA basis there would be no material LNG delivery from approximately late May to late October and the deliveries per week in some winter months could be as much as twice the LTA.
    - Water variability impacts on actual LNG requirements at this same grid load level could vary from virtually no LNG required in a year (about 16% of the 31 water years of record) to full capacity use of the two gas-fired units under severe drought conditions (average about 83 m^3/day with 6.1 trips per week for A-Train units and 9.0 trips per week for Tridem units).

- Under the Base Case grid load forecast with Alexco, LNG generation over the full year (2015) is estimated at 24.4 GW.h under long-term average (LTA) hydro generation, requiring on average 26.29 m^3/day of LNG:

- Averaged over the full year, this LTA requirement would approximate 1.93 trips per week with A-Train units (95.3 m^3/unit) and 2.85 trips per week with Tridem units (64.5 m^3/unit); however, on LTA basis there would be no material LNG delivery from approximately late May to late October and the deliveries per week in some winter months could be as much as twice the LTA.
- Water variability impacts on actual LNG requirements at this same grid load level could vary from virtually no LNG required in a year (about 16% of the 31 water years of record) to full capacity use of the two gas-fired units during some winter weeks under severe drought conditions (average about 83 m^3/day with 6.1 trips per week for A-Train units and 9.0 trips per week for Tridem units).

The variability indicated above is one of the LNG supply chain challenges. It is noted that addressing low water conditions that required greatly increased weekly deliveries would likely be forecast six or more months in advance and would allow for certain levels of planning if additional haul unit access was to be needed. The capability of units to meet requirements will vary depending on the LNG supply source. For example, assumptions used to estimate updated LNG haul costs (see YUB-YEC-1-44) result in the following estimates of LNG trips per week for fully loaded units operating seven days per week:

- A-Train units or Tridem units would average 2.85 trips per week from Calgary, and 6.0 trips per week from Fort Nelson.

- Full capacity use of two gas-fired units during some winter weeks under severe drought conditions would require
  - From Calgary: 2.1 A-Train units and 3.2 Tridem units;
  - From Fort Nelson: 1.0 A-Train units and 1.5 Tridem units.

(f)

No contingencies are currently in place that allow placement of LNG from alternative sources in the event of a closure of the Alaska Highway segments having no alternative Yukon access from BC, i.e., portions of the Alaska Highway in Yukon west of intersection with the Stewart-Cassiar-Highway. Based on the available record Alaska Highway closures are not expected to be a significant concern. Specifically, the following are noted:

- With regard to closures from Dawson Creek to the Yukon border, specific data is not tracked, or available, however, Yukon Energy has contacted relevant departments to confirm that closures along this stretch of the Alaska Highway would not be an issue or concern for heavy haul shipping based on historical experience.

- With regard to closures between south Yukon and Whitehorse Attachment 1 to this response provides Alaska Highway South – Whitehorse section to Watson Lake section road closures from 2008 to 2014. This document lists total closures over a six year period and indicates as follows:
    - Total of 10 winter closures (3 at Swift River, 2 at Teslin, 3 at Watson Lake and 2 at Whitehorse – ranging in duration from 15 hours, 17 minutes to 1 minute.
    - Total of 3 summer (all at Whitehorse) – ranging in duration from 7 hours, 25 minutes to 1 hour and 4 minutes.

Aside from the rarity of such events and the absence of practical options that would provide supply in the time needed prior to a closure ending, it is noted that the overall grid reliability for generation will be protected through LNG storage at site plus the extensive diesel generation capacity that still remains on the grid. The available mix of diesel and LNG generation is utilized at Inuvik to provide reliable power generation notwithstanding expected closures of Dempster access for approximately two months each year (one month each in spring and early winter).

(h) and **(i)**

The A-Train preliminary design addressed the key issues relevant to Yukon regulators, including weight, width and length restrictions and vehicle dynamics and stability performance assessments, in order to grant specific approvals subject to specific commitments. YEC was advised in October 2013 that Yukon Highways and Public Works would accept the vehicle performance characteristics as applied for.

A-Train approvals in BC and Alberta require review of similar parameters in order to secure waivers such as are granted for specific haul loads on specific routes. Time frames for such approvals remain uncertain, and may be facilitated by clarity as to the specific experienced transport haul contractor engaged by YEC (in that such contractors

normally are the ones who secure such permits or approvals as required for specific loads).

ALASKA HIGHWAY SOUTH
WHITEHORSE SECTION TO WATSON LAKE SECTION
ROAD CLOSURES 2008- 2014

Season	Highway	District Name	Duration	Camp Totals (H:MM)	Season Total (H:MM)	Grand Total (H:MM)
Winter	001	Swift River	0:05			
Winter	001	Swift River	3:08			
Winter	001	Swift River	5:57			
			SWIFT RIVER TOTAL	9:10		
Winter	001	Teslin	0:01			
Winter	001	Teslin	5:55			
			TESLIN TOTAL	5:56		
Winter	001	Watson Lake	0:03			
Winter	001	Watson Lake	15:17			
Winter	001	Watson Lake	13:45			
			WATSON LAKE TOTAL	29:05		
Winter	001	Whitehorse	0:02			
Winter	001	Whitehorse	0:01			
			WHITEHORSE TOTAL	0:03		
			WINTER CLOSURES TOTAL		**44:14**	
Summer	001	Whitehorse	1:04			
Summer	001	Whitehorse	7:25			
Summer	001	Whitehorse	1:04			
			SUMMER CLOSURES TOTAL		**9:33**	
					GRAND TOTAL	**53:47**

TOPIC: **Project components**

REFERENCE: **Application, page 5 and page 6**

2. Components on Expanded Site Area: Construction and operation of the following components on the Expanded Site Area:

a. LNG truck offloading, storage, and vapourization facilities and related infrastructure, including up to three 166.5 m3 and two 120 m3 storage tanks, a short all weather access road from Miles Canyon Road for truck offloading and access to the components on the Expanded Site Area, vapour barrier, fencing and other facilities required for safe operation.

4. Utility Trench on the WTGS [Whitehorse thermal generating station] for an underground pipe system between the existing WTGS diesel plant and the facilities on the Expanded Site Area for:

a. Water supply to the Expanded Site Area for fire suppression;

b. Glycol/water heating system to make use of the heat produced by the engines located in the existing WTGS facility; and

c. Natural gas supply for conversion of the existing oil boiler to natural gas, future conversion of existing diesel engines to fuel blend (diesel and natural gas), and/or future installation of new gas or dual fuel engines at the existing WTGS service bays previously used by diesel engines that have been removed.

PREAMBLE:

The Board requires further information.

QUESTION:

a) The Board notes that the expanded site area is to include “up to three 166.5 m3 and two 120 m3 storage tanks.” If all five storage tanks are not included in the

business case, please provide an explanation as how many storage tanks are included in the business case and what size they are.

b) Is the water supply to the area meant to extinguish a liquid natural gas fire?

c) Please explain why the utility trench is required to accommodate "natural gas supply for conversion of the existing oil boiler to natural gas?" How is the current oil boiler utilized?

d) With respect to part (c) of the above quote, is YEC proposing to include in its LNG project proposal (cost/benefit analysis) an underground piping system between facilities on the expanded site and the existing WTGS diesel plant (P126) that, in future, would enable the future replacement of existing diesel generation units to future gas or dual fuel generation units? If yes, please explain the reasons for doing so.

e) Are the utility trench infrastructure costs shown above included in the Table 3-1 of the Application?

ANSWER:

(a)

The three 166.5 m^3 storage tanks are to be installed in 2014 and are included in the business case for development of the Project in combination with up to three engines, resulting (at full capacity daily operation of the engines) in a minimum of 6 days storage with the two initial engines and four days storage when three engines are installed. The Application has also addressed the potential to add in future at least two additional smaller storage tanks (240 m^3) on the site if it was decided in future that YEC wanted to retain a minimum of six days storage when three engines are installed, however, neither these nor any other potential additional storage capacity that could be located on the site are included in the business case to be reviewed at this time.

(b)

No. The water supply to the area is not meant to extinguish a liquid gas fire. A number of fire suppression systems are integrated into the LNG facilities plant design including fire

suppression extinguishers, fireproofing of critical structures located in process areas, designated restricted areas and management controls to minimize potential ignition sources in areas where flammable gas may be present.

(c)

Natural gas piping to the existing diesel plant is being provided for all of the reasons noted, including (in addition to conversion of the existing oil boiler to natural gas) future conversion of existing diesel engines to fuel blend (diesel and natural gas) and/or future installation of new gas or dual fuel engines at the existing WTGS service bays previously used by the diesel engines that have been removed. The current oil boiler is used for heating of the existing WTGS building, the diesel engines blocks and hydro intake canal. The latest design calls for the replacement of the oil boiler with a dual fuel (diesel and natural gas) boiler as the existing boiler has been found to be non-convertible. The latest design for the piping is to be direct buried as it is more cost effective than a utility trench. Conversion to natural gas will provide cost savings as well as opportunity to cost effectively utilize LNG storage boil off gas (and avoid venting).

(d)

YEC's Project includes a buried piping system as noted that would enable future replacement of existing diesel generation units to future natural gas or dual fuel generation units, as well as conversion of existing diesel engines to blend fuel (diesel and natural gas) and provide natural gas to heat the building, engine blocks and intake power canal.

From the outset, the Project was designed to modernize the WTGS facility including the ability to use natural gas within the facility to displace diesel in engines and the existing oil boiler, and the underground piping system was always planned to connect the LNG storage and vapourization facilities (which would need to be located at some distance from the existing WTGS diesel plant) with the existing diesel plant. When it was decided to use modular gas-fired engines located outside the WTGS diesel plant to replace WD1 and WD2, the Project continued to retain the underground gas piping system. In addition to providing immediate benefits from converting the existing oil boiler, at minimal added cost the piping is sized to facilitate future added benefits related to either blend fuel use in existing diesel engines or replacement of remaining diesel generation units to future natural gas or dual fuel generation units.

(e)

Yes. Estimated costs for natural gas piping, water supply piping and glycol/water heating system (i.e., the elements proposed for the utility trench) were included in Table 3-1 of the Application and in the updated capital cost estimates for "LNG-Site Development" provided in YUB-YEC-1-1(d).

TOPIC: **Safety and training/ employee complement**

REFERENCE: **Application, pages 15 to 16**

While the consequences of a fire, explosion or cryogenic burn may be high, the likelihood of such an event occurring with such consequences is considered to be extremely low. YEC's existing WTGS operations provide long-term experience addressing such risks related to use of diesel fuel at this site. YEC is required to have measures in place to address such events including an emergency response plan, an updated spills management plan and training for on-site workers and for drivers transporting LNG.

In summary, adverse effects on health and safety related to possible accidents and malfunctions with LNG and natural gas will be addressed through a comprehensive range of well established measures, including application of existing non-discretionary legislation, standards and codes, regulators' responsibility to ensure safety through regulation of the Project, and safety measures being applied by the proponent, including primary containment, secondary containment, safeguard systems and separation distances. Based on these measures, the Project's adoption of a new fuel (LNG and natural gas) will be properly and prudently managed in the same way as current WTGS facilities properly and prudently manage operations with diesel fuel.

(Footnote 15) Yukon Energy will also adhere to appropriate LNG storage and transfer protocols such as CSA standard Z276-11 as well as applicable fire prevention codes, and will use equipment that meets or exceeds the safety and industry standards making a spill or unwanted ignition highly unlikely.

PREAMBLE:

The Board requires further information.

QUESTION:

a) If the consequences of an event occurring are considered high, how was it determined that the likelihood of such an event occurring is extremely low?

b) Please identify the impact to the area of a worst-case incident occurring. Were any considerations given for an alternative location for this project? If not, why not?

c) What expertise does YEC have regarding the handling, storage and vapourization of LNG and what additional operations training might be required for employees to safely operate the LNG equipment?

d) Will YEC directly hire people with experience in this area or contract out the services?

e) In the event of a spill or facility explosion, does YEC have an approved emergency response plan that has been considered and accepted by the City of Whitehorse Fire Department?

f) Please provide the updated measures in place that address the risks related to WTGS diesel and proposed WTGS LNG fuel operations, including an emergency response plan, a spills management plan and training for on-site workers and for drivers transporting LNG.

g) Please provide a copy of YEC's most recent corporate safety audit.

h) Please provide examples where YEC will use equipment that exceeds the safety and industry standards.

i) What does YEC expect in terms of changes to annual insurance premiums regarding the storage and vapourization of LNG and the running of natural gas generation units?

ANSWER:

(a)

As described in the above-referenced quote, the Corporation has extensive experience working in high risk activities. While the consequences of an event can be severe, by implementing the control structures referenced (i.e. compliance with regulations codes

and standards, safety design considerations etc.) the probability of such an event is reduced to an acceptable level.

(b)

The definition of a credible worst probable case in terms of impact radius is specifically addressed in CSA Z276-11.

The CSA Z276-11 standard provides guidance to determine credible worst-case scenarios. As such, the following three scenarios were identified:

a) Ignition of the natural gas vapours above the remote impoundment following a LNG spill;

b) The maximum flow of LNG that could be spilled from a 10-minute spill from the largest branch connection, 60 mm (2 in) or smaller, on the piping system serving the impoundment;
    i. This condition is met by the 1.5" pipe going to the vaporizer with a flow rate of 568 gallons per minute;

c) A spill of the entire volume of one cryogenic tank.

The Scenario A relates to a catastrophic failure of one of the LNG storage tanks followed by the ignition of the LNG contained in the remote impoundment area. Using the criteria explained in Section 5.2.3.2.2 of CSA Z276-11, assuming the impoundment pit design (7,59m by 7.59m by 3.17m deep [below grade]), this scenario was modeled and the zones for radiant heat fluxes of 5 kW/ m^2, 9 kW/ m^2 and 30 kW/ m^2 and compared against the criteria provided in Table 1 of CSA Z276-11.

- Both the 9kW/m^2 and the 30 kW/ m^2 zones fall within the YEC property so the exposure limits set out in Table 1 are not applicable.

- The 5.0 kW/ m^2 radiant heat zone extends 43.9m to the south, east and west and 47.3m to the north from the centre of the impoundment area; this radiant heat zone will either remain within the YEC property or (for areas to the south, east and west) between the YEC property line and the edge of the adjacent pavement or rail line. To the extent that this radiant heat zone extends beyond YEC's

property, YEC is seeking to secure no-build easements from the adjacent property owners such that this radiant heat zone will not extend beyond a property line that can be built upon.

Oxygen deprivation occurs at concentrations of natural gas in air well above the lower flammability limit (LFL). Asphyxiation of anyone outside the property line of the facility from natural gas originating on the proponent's site is not a credible scenario. Employees of the proponent who are authorized to work inside the area where LNG is stored will be trained on the hazard of asphyxiation. Hydrocarbon detectors will be used and will be set to alert personnel should hydrocarbons at a fraction of LFL be detected, allowing personnel to be extra vigilant to the associated dangers of hydrocarbons in the atmosphere.

Both scenarios are deemed worst probable case and modeling has shown impacts would be limited to the site or would remain within the property line that can be built upon.

The option of developing a new "greenfield" site for the Project in the Whitehorse area and separate from the WTGS was considered, but was not found to be cost effective or practical. The Whitehorse Thermal Generating Station was determined to be an optimum location for the following reasons (please also see response to YUB-YEC-1-10(c)):

- Whitehorse is the nearest practical grid location for LNG deliveries from Alberta or British Columbia.

- Whitehorse is the location of the Yukon grid's largest load center.

- The conversion project offers the opportunity to use new gas fired generation to modernize the Whitehorse plant facilities, with its established infrastructure (including transformer capability and on site staffing needed to operate and maintain the remaining diesel plant, good road access).

- Existing assets greatly facilitate cost effective development of the Project, concurrent with the retirement of existing diesel capacity at these facilities.

- Major elements of the existing diesel plant at the WTGS will continue to be required over at least the next decade under any scenario examined.

(c)

The Corporation formed a Project training committee in 4Q, 2012 with a mandate to understand the use of LNG and natural gas as a fuel for utility power generation and ensure policy, procedures and training were developed for the safe use of this fuel source.

The following activities were completed in 2013:

- A site tour of an operating LNG storage facility with truck loading site visit at Tilbury Fortis BC facility was undertaken by the committee members;
- Discussions held with LNG Users (Canaport terminal, Fortis BC terminal) by conference call;
- Discussions held with recommended LNG Safety Trainers GTI from Chicago;
- HS&E Plans and Procedures were developed for LNG, drafts filed with Oil & Gas Branch as part of Gas License Application;

The following training activities will be undertaken in 2014:

- A Training Plan has been developed for operators and maintenance staff involving on-line E-Learning LNG principles, characteristics focused on plant safety training. This is to be followed by a 1-week customized (for the WTGS facility) training in Whitehorse. This customized training will include familiarization with LNG CSA code Z276.11, NFPA and YOGA Regulations;
- Training for a YEC LNG Fire Brigade (as first responders) of up to 10 staff will be undertaken prior to commencement of commercial operation;
- Hands-on operational training at an operating LNG facility is will be undertaken for the operating staff that will be directly involved with LNG;
- Training to be coordinated with local Fire Dept and Fire Marshall's office;

- E-learning training will begin in June; with more detailed/advanced training to follow through to start up of operations;

- Vendor led training to be conducted for operating and maintenance staff as part of commissioning by Gas Drive (NG engines), GP Strategies (Tanks, vaporizers, truck loading/unloading).

(d)

Yukon Energy will ensure its existing operations, maintenance, engineering, health, safety and environmental workforce receive appropriate training prior to commencement of commercial operation of the Project. Specific skill sets in areas that the existing staff do not have will be outsourced until that skill set is developed within Yukon Energy. For example, maintenance activities requiring a gas fitter ticket will be performed by qualified local contractors initially as Yukon Energy maintenance staff to do not currently have this certification.

(e)

Yukon Energy is working with both the City of Whitehorse Fire Department and the Fire Marshall Office to develop a joint training program, develop emergency response plan and update its existing spill response plan to include provisions for LNG. In addition, both the City of Whitehorse Fire Department and the Fire Marshall Office are involved in the early stages of the design of the external (i.e., non-natural gas fire) fire suppression system.

(f)

Training for on-site workers is addressed in response to YUB-YEC-1-7(c). Driver training will be conducted by the transportation contractor. The LNG truck unloading will be supervised by a fully trained Yukon Energy operations staff member.

Please see Attachment 1 to this response for the Emergency Response Plan and see Attachment 2 of this response for the Spills Response Plan.

(g)

Please see Attachment 1 (2012 Core Safety Audit) and Attachment 2 (Letter of Good Standing with the Northern Safety Network Yukon) to this response.

(h)

The design of this facility is based on very conservative assumptions that provide an additional margin of safety. For example, the vapour dispersion and radiation modelling done, required under CSA Z276.11, does not reflect any allowances for vegetation, fencing or other obstructions that will provide some mitigation of these effects. The use of closed circuit TV cameras in addition to requiring full time operators to remain within the vicinity of the truck loading area would have allowed the corporation to reduce the truck unloading spill assumption from a 10-minute spill (the default standard in the LNG code) to a much shorter spill period thus reducing the vapour containment barrier requirements. The additional safety factor is ensuring vapour cloud containment of a larger spill was felt to be justified.

(i)

Discussions with YEC's commercial insurance broker indicate that the addition of these assets will have the following effect on premiums:

- Property – premiums will go up directly in relation to the value of the assets constructed, i.e., premiums are currently charged at $0.900/$1,000.

- Liability – the broker indicates minimal impact on liability premiums owing to the addition of these assets.

Actual impact to this expense item will not be known until the assets are included in the next renewal following completion of the Project.

FACILITY EMERGENCY RESPONSE for LNG STORAGE & HANDLING

(In response to Yukon's *Gas Processing Facility Regulations*, S.11(f)

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Positions Identified in this Draft Emergency Response Plan:
Manager, Systems & Mechanical Operations
Manager, Health & Safety
Manager, Environmental Assessment & License
Director, Operations & Engineering Services
Manager On Call
Shift Engineer

PURPOSE

These procedures describe the necessary minimum actions that Yukon Energy employees must take when responding to an emergency at the YEC Liquefied Natural Gas facility. This document complies with the CSA-Z276 Standard, the Yukon's Gas Processing Facility Regulations, the Yukon's Occupational Health and Safety Act and the Yukon Occupational Health &Safety Regulations.

OVERVIEW

The Yukon Energy Corporation Liquefied Natural Gas offloading, storage and vaporization generation facility and supporting infrastructure are large, complicated and sophisticated facilities. Our purpose is to produce electricity for the Yukon. To accomplish this task we employ large, energy intensive systems.

Yukon Energy takes health and safety seriously. It is our goal to have zero accidents, incidents or emergencies that have any safety or environmental consequences. It is prudent to put emergency response procedures in place and exercise them regularly to ensure that each team member is competent and confident in the event they have to response to an emergency. To the greatest degree possible, Yukon Energy's management will provide all mechanical and physical facilities required for personnel safety and health, keeping with the highest standards.

Yukon Energy has effective safety and environmental management systems that integrate operations and technical systems with the on-going management of financial and human resources to ensure compliance with Z276, and the Yukon's Oil and Gas Act and Regulations.

SAFETY CONSIDERATIONS IN LNG OPERATIONS

Yukon Energy's storage and use of natural gas considers the following four critical safety conditions and requirements:

1) Primary containment;
2) Secondary containment;
3) Safeguard systems; and
4) Separation

These four requirements for safety apply across the LNG value chain; from production, liquefaction and shipping, to storage and re-gasification. When we use the word 'containment' in this document, we are referring to safe storage and isolation of the LNG.

Primary Containment

The first and most important safety requirement for Yukon Energy is to contain the LNG. This is accomplished by using suitable materials for storage tanks and other equipment, and by appropriate *engineering design* throughout the value chain.

Secondary Containment
This second layer of protection ensures that if leaks or spills occur, LNG can be contained and isolated. Dikes or berms surround the liquid storage tanks to capture the product in the case of a spill. Secondary containment systems are designed to exceed the volume of the storage tank.

This manual and procedures also provide a 'checklist' of actions and considerations that must be referenced in an emergency.

Safeguard Systems
In the third layer of protection, the goal is to minimize the release of LNG and mitigate the effects of a release. For this level of safety protection, *gas, liquid and fire detection* to rapidly identify any breach in containment with SCC (remote) automatic shut off systems to minimize leaks and spills in the case of failures. Procedures, training and emergency response are operational procedures Yukon Energy uses to help prevent/mitigate hazards. Regular maintenance of these systems is also vital to ensure their reliability.

Separation Distance
The Gas Processing Facility Regulation (*Oil and Gas Act*) as well as CSA Z276-11 specify process equipment spacing for LNG. This means that Yukon Energy's LNG facilities will be sited at a safe distance from adjacent industrial, community and other public areas.

Yukon Oil & Gas Regulations & CSA Z276-11 (Industry Standards)
No system is complete without appropriate operating and maintenance procedures being in place. Pursuant to the Yukon's Gas Processing Facility Regulation 5(1), Yukon Energy will be compliant with the CSA Standard Z276-11 in all matters relating to the LNG facility.

The four conditions described above, along with the industry standards and regulatory compliance are vital to continuing Yukon Energy's strong industry and safety performance.

Yukon Energy's LNG facility will be equipped with:

1. A source of emergency power; and
2. Systems that are appropriate to the substations, the buildings, and all structures designed for the detection of explosive and flammable gases, toxic or noxious.

PRE-TRAINING FOR STAFF

Yukon Energy Corporation is responsible for providing Operations and Maintenance staff suitably qualified through prior training, education and experience on a similar plant design and similar equipment. YEC will be responsible for all familiarization and any required pre-training for the LNG Plant O&M staff, including but not limited to:

- Company Orientation
- Basic skills - mathematics, science, equipment principles, maintenance practices and operations practices, ability to read and understand all system drawings and documentation, basic computer literacy.
- Basic plant processes - basic principles of gas processing equipment
- Process plant operations - operating principles for gas processing facilities.
- Process plant maintenance - maintenance practices for gas processing facilities.
- Knowledge of principles of instrumentation and control systems including but not limited to control valves, relief valves, process control loops and general DCS operations.
- Process plant repair – rigging, welding, plumbing & pipefitter, millwright, electrical, instrument, etc. (as these skills may be required for individuals' job requirements.)
- Vendor maintenance/troubleshooting – except for LNG-specific vendor equipment.
- General Facility procedures and requirements
- Plant safety/security/firefighting safety and operating procedures including familiarity with process plant
- emergency response procedures
- General knowledge of and procedures for hydrocarbon product transfer
- Familiarity with and ability to understand environmental issues and Material Safety Data Sheets, etc.
- Government (local, provincial and/or federal) or other required certifications, training requirements procedures and regulations for plant staff.
- LNG Fire Fighting training
- Equivalent PIC (Person in Charge) Training for LNG transfer operations at other LNG Facilities.
- Conversant in English to an approved level of fluency sufficient for plant operations.

An LNG Plant Operator Certification program will be offered to YEC's Plant Operators. This training curriculum will cover 5 modules in:

- Covering LNG Fundamentals
- Gas Processing & Liquefaction
- Materials & Documentation
- Codes & Standards
- Storage
- Piping & Valves
- Pumps, Compressors & Vaporizers
- Instrumentation & Controls
- Safety, Operations & Security
- Utility & Support Systems
- Trucking
- Quality Assurance/Quality Control Program

TYPES OF LNG HAZARDS

The potential hazards of most concern to Yukon Energy flow from the basic properties of natural gas. Primary containment, secondary containment, safeguard systems and separation distance provide multiple layers of protection. These measures provide protection against hazards associated with LNG.

Explosion

An explosion happens when a substance rapidly changes its chemical state – i.e. is *ignited* – or is uncontrollably released form a pressurized state. For an uncontrolled release to happen, there must be a structural failure – i.e., something must puncture the container or the container must break from the inside. LNG tanks store the liquid at an extremely low temperature, about -160° C. (-256°F.) Yukon Energy's sophisticated containment systems will prevent ignition sources from coming in contact with the liquid. LNG is stored at atmospheric pressure – i.e. not pressurized – a crack or puncture of the container will not create an immediate explosion.

Vapour Clouds

As LNG leaves a temperature-controlled container, it begins to warm up, returning the liquid to a gas. Initially, the gas is colder and heavier than the surrounding air. It creates a fog, like dry ice does – a *vapour cloud* – above the released liquid. As the gas warms up, it mixes with the surrounding air and begins to disperse. Safety devices and operational procedures are intended to minimize the probability of a release and subsequent vapour cloud having an affect outside the facility boundary.

Freezing Liquid

If LNG is released, direct human contact with the cryogenic liquid will freeze the point of contact. Containment systems surrounding an LNG storage tank are designed to contain up to 110% of the tank's contents. Containment systems also separate the tank from other equipment. PPE controls at YEC require all facility personnel to wear gloves, face masks and other protective clothing as a protection from the freezing liquid when entering potentially hazardous areas. This potential hazard is restricted within the facility boundaries and does not affect our Whitehorse neighbours or other communities.

EMERGENCY PROCEDURES

Yukon Energy will add the LNG safety and emergency drill programs to the current life safety plans and will assist any employees involved in exercises. This program is designed to test the plan while training the people involved. This program will apply to all emergency exercises and drills at the Yukon Energy LNG facility, including those that will involve the City and Territorial emergency response groups.

This program will provide an effective means of training and enhancing response procedures and individual skills. The benefits from these training drills and exercises will include:

- Revealing weaknesses in the plans and procedures before real emergencies occur
- Identifying deficiencies in resources (both in manpower and equipment)
- Improving the level of coordination between various response personnel, departments, agencies and other personnel
- Clarifying individual roles and areas of responsibility
- Increasing government and community cooperation with the facility's emergency planning effort
- Enhancing overall emergency response capabilities.

Three basic types of drills and exercises that may be used to test emergency preparedness at YEC are:

1) Table top exercises
2) Functional Drills
3) Full-scale Exercises

Preparation and Planning
Typically emergency procedure planning consists of annual full-scale exercises and a number of drills as determined by the SCC and Operations Manager. All exercises and drills must be prepared and planned to reflect actual hazards and risk at the YEC LNG facility.

At a minimum, the following scenarios will be scheduled within a timeframe established by the SCC and Operations Manager and the Health and Safety Manager:

FIRES
- Fire extinguisher
- Deluge systems
- Master stream
- Hand lines

LOSS OF UTILITIES
- Electricity
- Instrument Air
- Nitrogen
- Black Screen
- Radio Communication

SAFETY

Man-Down
Victim Packaging
Facility/Site evacuation

ENVIRONMENTAL

LNG Spill
Other Spill

OTHER PROCEDURES

Public Complaint Procedure

Should an employee receive a report or complaint from a member of the public, the employee shall obtain from the informant, the following:

- The name of the person complaining;
- Location;
- Telephone Number;
- All available information related to the condition.

This information must then be reported to the Supervisor or Lead Hand. There is a YEC Public Complaint Form that will be utilized.

Cause of Complaint – Environmental or Safety Compliance Concern
If environmental or safety compliance issues are involved, proper reporting is to be carried out by the Manager, System & Mechanical Operations which will include the following:

- Possible immediate process shut down (as per draft Oil & Gas Regulations).
- Completing required forms and processes for safety compliance issues or environmental impacts.
- Referring details of Complaint to appropriate public enforcement agencies or processes for emergency and public safety issues, or
- Applying internal procedures for worker or operational safety issues.

The Manager, Systems & Mechanical Operations will:

- Advise the Manager, Environmental Assessment and Licensing of the complaint and of the action taken/planned, and conversation documented; or
- Advise the manager, health & Safety of the complaint and of the action taken/planned and conversation documented.
- Contact the complainant and follow up until the complaint is resolved.
- Ensure copies of all documentation are kept on file by the Operations Administrative Assistant.

Cause of Complaint – Noise, Aesthetics or Odours
If the complaint concerns any of the above, the Manager, Systems & Mechanical Operations will immediately address the current situation for causal effects. The Manager, Systems & Mechanical Operations will then:

- Initiate immediate process shut down if required, as per draft Oil & Gas Regulations.
- Report the complaint and the result of the assessment to the Director Engineering Services and Operations, or designate.
- Log the complaint and action taken.
- Follow up with the Public Complaint Form *(Appendix A).*

The Director, Operations & Engineering Services or his designate will:

- Advise the Yukon Department of Environment of the complaint and of the action taken/planned, and conversation be documented.
- Contact the complainant and follow up until the complaint is resolved.
- Ensure copies of all documentation are kept on file for 5 years.

Communications Emergencies Procedure
Telephone and radio voice communications are in place at Yukon Energy. *Under no circumstances will employees, contractors or truck drivers be allowed to carry cell phones in the LNG facility.*

Yukon Energy's System Control Centre (SCC) has a SCADA system that provides: status, analogues, metering and control functions for substation equipment located throughout the Territory, available through data communications circuits.

A public information procedure regarding power outages, winter power outages, forest fires and earthquakes is in place.

Serious Injury Procedure

Yukon Energy functions 24 hours per day, 7 days a week. Great care is taken to identify and control hazards, but the consequences of inadvertent contact with hazardous energy could be serious and injuries could occur. YEC has a plan in place to respond effectively to an injury in the most unlikely event one should occur.

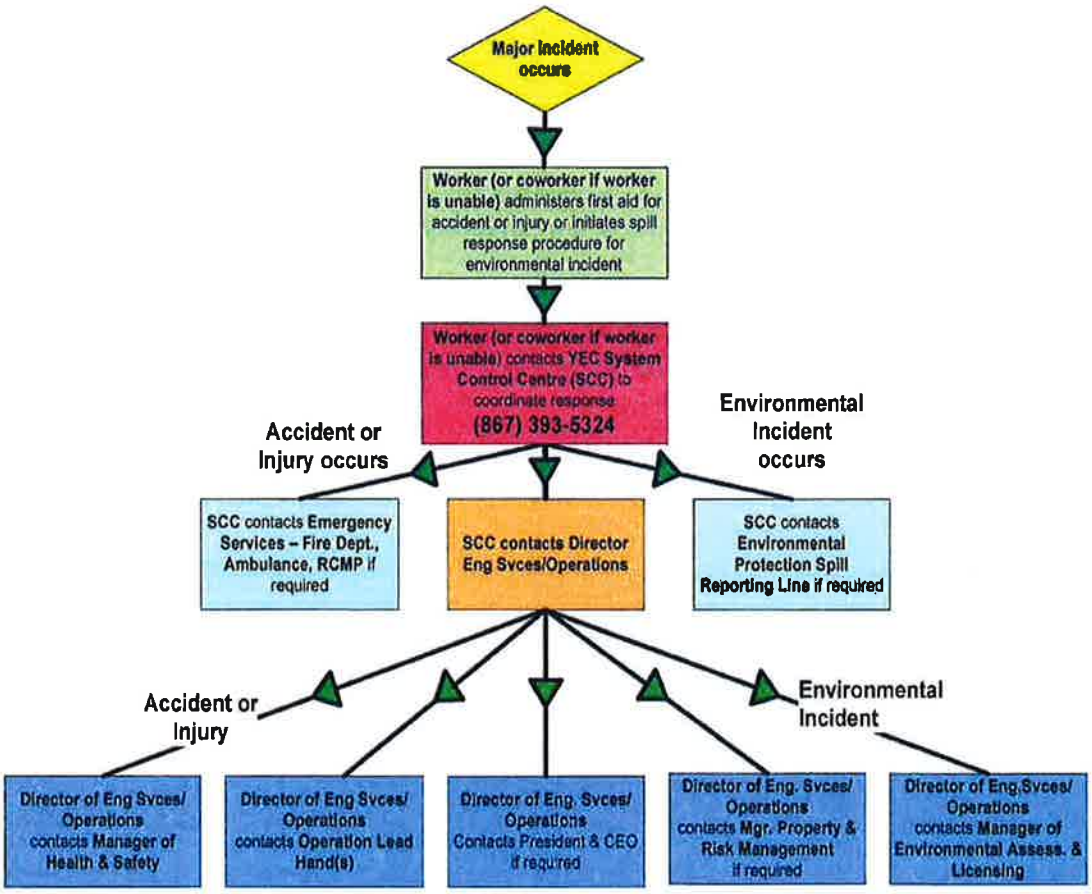
Step One – Call for first aid help. If safe to do so, remove the seriously injured person from immediate harm. Be sure to carefully assess that moving the victim can be done without further injury to the victim or harm to the rescuer.

Step Two – If required, call for Medical Aid – 911. Provide as much information to the 911 Operator as possible, including victim information and any immediate workplace hazards related to the cause of the injury – i.e. chemical spill, live electrical supply, etc.

Step Three – Ensure the main gates are open so the ambulance service can easily access the Yukon Energy property.

Step Four – Ensure the Manager on Call and the Manager, Health and Safety are notified of the incident. Ensure the Director, Operations & Engineering Services has been notified. Ensure the President and CEO has been notified. Review the following Notification Protocol matrix for infrastructure accident or human accident.

Notification Protocol Matrix



Step Five Contact the Yukon Workers' Compensation Health & Safety Board at 24-hr Number: (867) 667-5450 or the Environmental Protection Spill Reporting Line at (###) ###-####

SITE EVACUATION PROCEDURE

In the event of an emergency, the Shift Engineer may decide to initiate a site evacuation by sounding the evacuation alarm. In this event the following procedure will be used:

- Evacuation Alarm – is a very loud electronic evacuation signal. In the event that the plant needs to be evacuated, the evacuation alarm will be activated by the Shift Engineer.
- All personnel up hearing the evacuation alarm **must** immediately leave the site.
- Keep calm, do not run, and proceed in an orderly manner to the nearest safe Mustering Point. Assist anyone who may be having trouble leaving the area.
- Once outside, immediately proceed to the Administration Building. There are telephones that can be used in the Administration Building. All evacuees will remain in the Administration Building until they are authorized to leave.
- A designated person will be responsible for keeping a daily list of all contractors / visitors and employees on site. All employees are responsible for reporting the arrival and departure of any contractors/visitors on site. The designated person is also responsible to ensure a radio is available in the Administration Building.
- Once everyone is at the designated meeting area, the designated individual will take a head count, reference it against the daily list of contractors/visitors and team members on site, and report the results to the Shift Engineer (i.e. everyone is accounted for.)
- A person will be assigned to answer any incoming telephone calls. If necessary, the Shift Engineer or designate will call for emergency response and notify the City of Whitehorse, the fire Department, OH&S, Yukon's COO for the Oil and Gas Directorate and any others as appropriate.
- A head count will be taken once all evacuees are in the designated meeting area.
- SCC will be notified to open the gate (if required) and allow emergency response vehicles to enter.

EMERGENCY EVACUATION - ROLES AND RESPONSIBILITIES

Shift Engineer

- Activates the alarm
- Ensures Fire Department is contacted
- Ensures the Director, Operations & Engineering Services is notified of the incident
- Initiates full emergency facility shut down
- Initiates full emergency plant shut down
- Evacuates any remaining personnel once plant is secure or as otherwise deemed appropriate.

Assistant Shift Engineer

- Check on emergency or fire and confine, control or extinguish if possible.
- If required, meet any emergency vehicles responding, at the gate.
- If evacuating due to a fire, ensure the fire pumps are operating.

Manager Health & Safety / Safety Coordinator

- During daytime business hours, the Manager, Health & Safety and the Safety Coordinator will be designated individuals who will assist with some of the responsibilities in carrying out emergency evacuations.

- Should the emergency occur after business hours, the Manager On Call or the Shift Engineer will assume these duties – or will assign those duties as deemed necessary.

FIRE PROCEDURES

In the event a fire does occur either at YEC or in any adjacent City of Whitehorse areas that may threaten the safety of YEC personnel, proper procedures must be followed.

Automatic fire protection systems protect sensitive areas and notify staff in the event of a fire. This system includes fire extinguishers suitable to an LNG facility and alarm activation stations that are strategically located throughout the facility.

Firefighting

In accordance with National Fire Protection Association (NFPA) 600, Yukon Energy will create an Incipient Fire Brigade that will prevent any fire from spreading. In the event of a fire, the City of Whitehorse Fire Department will respond.

The first priority will be to contact the City of Whitehorse, Fire Department. The MSDS for this product (Liquefied Natural Gas) advises dry chemical (purple K) high expansion foam is best suited to put this type of fire out. Firefighters must also don SCBA.

Maintenance records must be kept in a computerized maintenance system.

Fire extinguishers must be equipped with inspection tags; extinguishers will be inspected monthly.

YEC employees will be trained to use fire extinguishment equipment.

Fire System Drawings & Records

To be developed

OFFSITE HAZARDS

Yukon Energy trucks, mobile cranes, other trucks as well as other unforeseen conditions, could present a LNG fire risk to YEC. The Director, Operations & Engineering Services or his designate must ensure all corrective action is taken to ensure fire risks are minimized.

If required, fire department authorities may be contacted to minimize the risk from adjacent areas.

EXPLOSION PROCEDURE

In the event of an explosion at the facility, it will be the responsibility of the Manager, Systems & Mechanical Operations to ascertain the cause and extent of the damage and immediately notify the Yukon's Chief Operating Officer for Oil & Gas. A preliminary report will be provided as per regulation 43.1 (a). The subsequent action plan will depend on the initial assessment. In all cases, Yukon Energy will err on the side of caution, particularly with respect to the safety of personnel and the public.

Shift Engineers must have current plant operation information and knowledge of the activities in progress and use such information to interpret the cause of explosions. The Shift Engineer may evacuate the plant using the evacuation alarm system and ensure that personnel are counted as prescriber in the Facility Evacuation Procedure.

Based on observation and assessment, the Manager, Systems & Mechanical Operations will establish and exercise a safe shutdown plan. Emergency support should also be dispatched if injuries or fire is evident. All personnel will leave the facility at the first sign of risk to their safety.

Notification to customers, management should proceed after the site has been secured. Before returning equipment to service, the Director, Operations and Engineering Services or his designate must be consulted.

LNG LEAK PROCEDURE

Liquefied Natural Gas leaks have the potential to asphyxiate and are a serious explosive risk. As such, natural gas leaks will be handled with extreme care and consideration for the safety of personnel, the public and equipment. Maintenance of natural gas systems will be a high priority, and it's planning and execution will be audited in accordance with Yukon's Gas Processing Facility Regulation, 32(1) **External Audits**.

As per CSA-Z276, a gas monitoring system with warning lights (green, red, yellow) and audible horns will be installed in the facility. This system will be integrated into the system and will monitor all areas for any high concentrations of liquefied natural gas.

Any incidents involving a leak of LNG is immediately reportable to the Chief Operating Officer, of the YT Gas Processing Plant Regulations.

UNAUTHORIZED ACCESS PROCEDURE

Unauthorized access to the Yukon Energy LNG facility will be prevented. Gates will be kept closed at all times and any contractors or other visitors will be required to sign in at the Main Office. In accordance with the Regulations, all visitors and contractors will be familiarized with the components of the safety program necessary for their personal safety before entering the LNG facility.

SPILLS RESPONSE PROCEDURE

To be integrated into the existing *Whitehorse / Hydro / Diesel / Substation Spill Response Plan*

File # 2500-00-01

YUKON ENERGY	DEPARTMENT:	INQUIRIES TO:	TOPIC:	Last Review Date
EMS-EWP-011 SPILL RESPONSE PLAN- WHITEHORSE	Operations	Director, Operations	Spill Response/Hazardous Material Location Page 1 of 73	February 24, 2014
	ISSUED:	REVIEW DATE:	APPROVED BY:	Revision #
	May 2000	Annually	Director, Operations	4

WHITEHORSE RAPIDS GENERATION SITE

SPILL RESPONSE PLAN

Yukon Energy Corporation
#2 Miles Canyon Rd
Box 5920, Y1A 6S7
Whitehorse, Yukon

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1.0 EMERGENCY CONTACT INFORMATION

SCC (Available 24/7)

Phone: **867-393-5324**

YEC Radio:

1. Ensure your radio is on the correct channel for your area.
2. Press and hold the "push to talk (PTT)" button (large button on left hand side of the mic)
3. While pressing the PTT button dial 1111 on the mic.
4. Voicecall your party.

If you are in the Aishihik Area, use channel 15

MOBILE RADIO OPERATOR CALL METHOD

1. Locate the your mobile channel on the Mobile Telephone Service Map according to your location
2. Change mobile channel
3. Hold radio key down to ring the operator
4. When operator answers, use you call sign to place a call to a phone number

YEC Radio Notes:

- The link can be enabled/disabled from the northern or the southern radio network.
- The link will automatically be disabled after five minutes of inactivity.
- When in the Carmacks area you will hear a beep-beep after enabling the link and a beep-beep-beep after disabling the link. Unfortunately these acknowledgment tones are not transmitted in other areas of the radio network.
- The radio link between the southern and northern networks is very long and heavy snow or ice fog between Carmacks and Stewart Crossing may render the link inoperable at times.

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2.0 INITIAL ACTION/SAFE APPROACH GUIDELINES

The following are intended as Guidelines. Consider the circumstances of each event and act accordingly.

NOTIFY SSC and SUPERVISOR IF AVAILABLE **SCC Phone# 867-393-5324**

- Arrange Call-Back time, if appropriate.

ALERT OTHER EMPLOYEES/PERSONS IN AREA

- Approach spill site from up-wind or, if indoors, ensure you have a clear escape route
- Establish Perimeter Security
- Evacuate, if necessary
- Eliminate Ignition Sources
- Commence documentation

USE THE BUDDY SYSTEM

IDENTIFY MATERIAL, SPILL SOURCE, ESTIMATE QUANTITY SPILLED AND POTENTIAL FATE

- Block Potential Escape Routes, if appropriate

IF SPILL CONTINUING, CONTROL SOURCE, IF SAFE TO DO SO

- **SUBSTATION SPILLS. DO NOT ENTER UNLESS AUTHORIZED. HIGH VOLTAGE: CONTACT SCC then LEADHAND ELECTRICAL MAINTENANCE 335-2902**
- Develop Initial Incident Response Plans (Defensive, Offensive or Non-Intervention)
- Refer to product MSDS. Wear appropriate PPE.
  (See "Fast Fact Sheets" in this Plan for spills of specific products.)

SUMMON RESPONSE RESOURCES, AS APPROPRIATE

UPDATE SCC and SUPERVISOR ON PROGRESS

Note: In some instances, initial on-scene personnel will only be able to monitor and/or contain the spill with resources at hand until assistance arrives.

DO NOT PUT YOURSELF at RISK

3.0 PURPOSE AND SCOPE

At this time this Spill Response Plan covers situations related to a spill or other unintended release of a liquid, solid and/or gas that may present a threat to those in a YEC facility or to the external environment.

This spill contingency plan applies to all spills that occur at Yukon Energy's hydro and diesel and liquid natural gas and compressed natural gas (LNG/NG) facilities located at #2 Miles Canyon Road. The Director of Operations and Leadhands of Mechanical, Electrical and Hydro Maintenance will review the plan yearly to ensure the information is current.

Purpose

The purpose of Yukon Energy's Hazardous Materials Spill Contingency Plan is to provide a plan of action for every foreseeable spill/release event at the Whitehorse Rapids Generating Facility. It defines the responsibilities of key response personnel and outlines the procedures for responding to spills in a way that will minimize potential health and safety hazards, environmental damage, and cleanup costs. The plan has been prepared to provide easy access to all the information needed in dealing with a spill.

It is the policy of Yukon Energy to initiate clean up activity when, in the opinion of its management, Yukon Energy is clearly associated, or likely to be associated with the spilled material. As well it is our company policy:

- To meet or surpass regulatory requirements;
- To provide protection of the environment using all of YEC's resources;
- To cooperate with other groups working on protection of the environment;
- To minimize the adverse effects of our activities on the natural and social environment;
- To keep employees, government officials and the public informed.

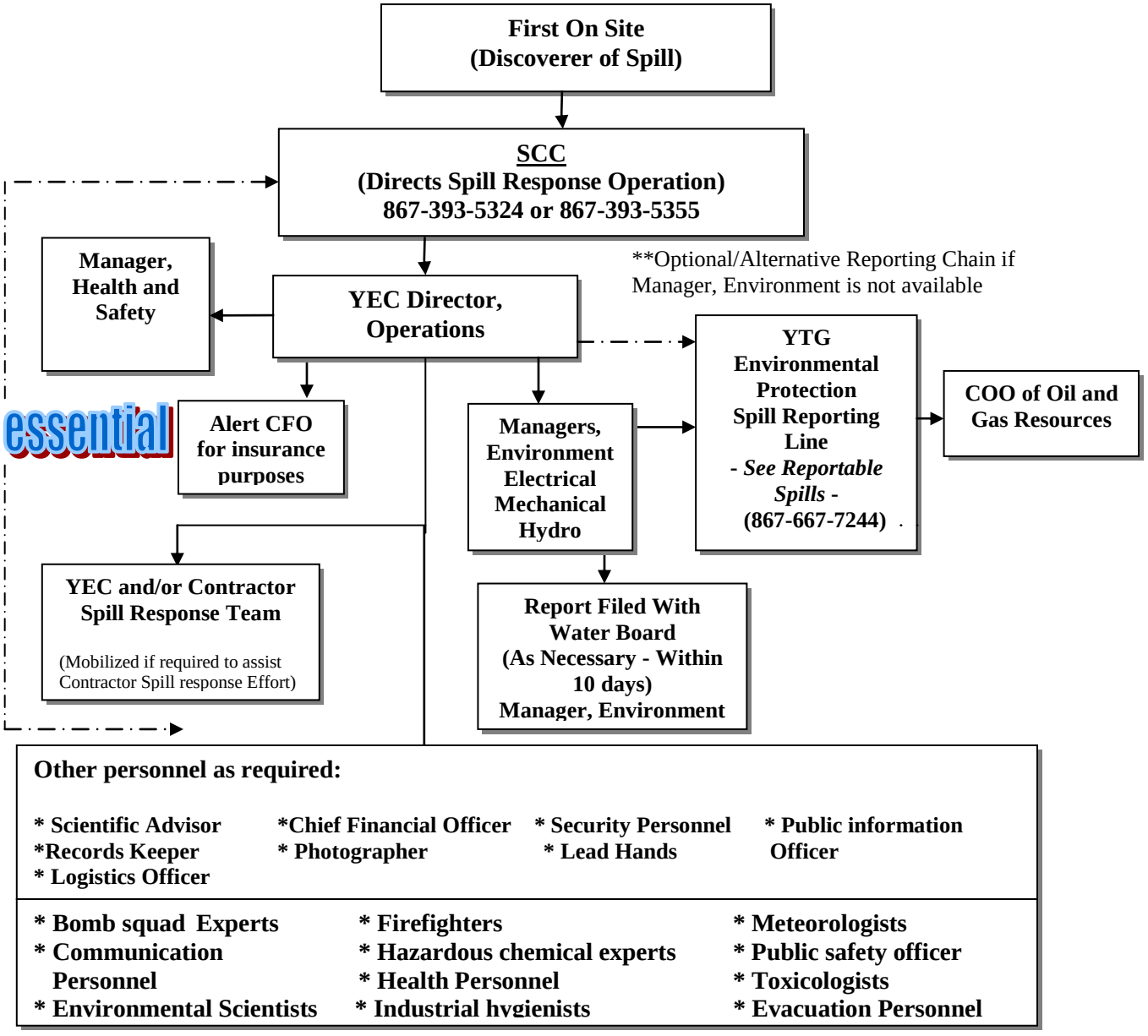
Scope

The Whitehorse Hydro/Diesel/LNG/NG/Substation Spill Response Plan, covers all hazardous materials stored and used at the Whitehorse Hydro, Diesel, LNG/NG and Substation sites. This document covers both spills on land, air as well as in adjacent watercourses (e.g., the Yukon River). This plan is approved yearly by the Director of Operations. Leadhands of Electrical, Mechanical and Hydro Maintenance will review the plan yearly to ensure the information is current.

4.0 NOTIFICATIONS

Figure 1. Contact/Reporting Flow Chart
Contact flow chart in the event of a fuel or oil spill. Qualified alternates will be contacted in the event someone is unavailable.

All spills of petroleum products of **5 litres** or more of fresh or unused **to permeable surface or water**, **0.5 L** of used waste oil or other hazardous materials must be reported to the 24 Hour Spill Report Line and the Chief Operating Officer of the Oil and Gas branch, by the Manager, Environment to insure that an investigation may be undertaken by the appropriate government authority. All amounts of all substances releases into water must be reported.



The specific information requested when a spill is reported to government is outlined in Yukon Energy's Environmental Work Procedure EWP-006 Spill Reporting
https://sp2010.yec.yk.ca/Departments/env/YECEMS/procedures/Lists/Work%20Practices/View2.aspx

5.0 RESPONSE ORGANIZATION

Response organization Structure (s) by Classification Level of Response

MINOR: Level 1 INCIDENT COMMANDER: **RESPONDER/SUPERVISOR**

is a spill of a minor nature that presents no significant threat to employees, property or the environment and absolutely no risk to the public. It can be cleaned up and remediated using manpower and equipment available at the facility or site.

Example: A litre of varsol was spilled on the shop floor. The spiller alerts those around him of the occurrence, that the incident has occurred and cleans the product up using a small spill kit. Waste is disposed of in an appropriate manner.

MODERATE: Level 2 INCIDENT COMMANDER: **LEAD HAND** or delegate

A medium spill event where there is potential risk to employees, property or the environment but no risk to the public. This level may require external assistance to contain, recover or remediate.

Example: A vehicle entering the Whitehorse facility has impacted and punctured several barrels of waste oil stored directly on the ground with no spill tray to catch any release.

MAJOR: Level 3 INCIDENT COMMANDER: **DIRECTOR, OPERATIONS** or delegate

A major spill event where there is a significant risk to employees, property, the environment and/or the public. Considerable internal and possibly external resources may be required to effectively respond.

Example: The 160,000L fuel tank in the yard of the Whitehorse facility has leaked and the product is escaping through a previously unidentified crack low on the secondary containment wall. The spill is spreading around the yard and entering the unpaved area adjacent to the property fence.

Responsibility to summon/manage external resources:

First Responders: SCC or personnel at the scene

Regulators: Manager, Environment or Delegate. Director of Operations

Contractors: SCC, Manager of Environment, Director of Operations, Lead hands

6.0 SPILL SITE SAFETY PLAN

Incident Name _____ ***Operational Period*** From _____ To _____

1. DESCRIBE THE INCIDENT AND SPECIFY THE SITE ENTRY OBJECTIVES

Description _____

Location _____

Incident Type

- ☐ Spill
- ☐ Gas release
- ☐ Explosion
- ☐ Fire
- ☐ Other _____
- ☐ Unknown

Site Entry Objectives under this Site Safety Plan

- ☐ Initial assessment or reconnaissance
- ☐ Account for personnel and/or rescue victims
- ☐ Source control
- ☐ Fire suppression
- ☐ Spill containment
- ☐ Spill recovery and/or cleanup

2. IDENTIFY PRODUCT HAZARDS

Consult MSDS; if no MSDS call CANUTEC at 613-996-6666 or "*666" (in Canada only)

Product Properties

Name _____
Estimated Amount _____
MSDS on Hand? _____
Gas / Liquid / Solid (circle)
Water soluble? _____
Specific gravity or vapor density _____

Product Hazards *(check all that apply)*

- ☐ Flammable (flash point _____ °C)
- ☐ Explosive (LEL range _____ to _____ %)
- ☐ Corrosive (corrodes _____)
- ☐ Reactive (reacts with _____)
- ☐ Toxic (IDLH _____; TLV _____)
- ☐ Carcinogenic

Potential Routes of Exposure to the Product *(check all that apply)*

☐ Inhalation ☐ Ingestion ☐ Eye contact ☐ Skin contact

3. IDENTIFY PHYSICAL SITE HAZARDS AND CONDITIONS

Physical Site Hazards

- ☐ Confined space
- ☐ Elevated area
- ☐ Pit or trench
- ☐ On or near water
- ☐ Unstable structure
- ☐ Electrocution
- ☐ Wildlife encounter
- ☐ Noise/vibration
- ☐ Extreme temperatures
- ☐ Low visibility
- ☐ Slip or trip hazards

Site Conditions *(as applicable)*

Air temperature _____
Wind chill temperature _____
Water temperature _____
Wind speed & direction _____
Precipitation _____
Humidity _____
Visiblity _____
Wave ht. (avg & max) _____
Speed of current _____
Direction of current _____
High/low tide times _____
High/low tide heights _____
Forecast _____
_____
_____
_____

Wind Chill Temperature Chart

Wind Speed (km/hr)

Effective temperature (°C)	0	10	15	20	25	30	35	40	45	50	55	60
10	8.6	7.9	7.4	6.9	6.6	6.3	6	5.7	5.5	5.3	5.1	
5	2.7	1.7	1.1	0.5	0.1	-0	-1	-1	-1	-2	-2	
0	-3	-4	-5	-6	-7	-7	-7	-8	-8	-9	-9	
-5	-9	-11	-12	-12	-13	-14	-14	-15	-15	-15	-16	
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-15	-21	-23	-24	-25	-26	-27	-27	-28	-29	-29	-30	
-20	-27	-29	-31	-32	-33	-33	-34	-35	-35	-36	-37	
-25	-33	-35	-37	-38	-39	-40	-41	-42	-42	-43	-43	
-30	-39	-41	-43	-45	-46	-47	-48	-48	-49	-50	-50	
-35	-45	-48	-49	-51	-52	-53	-54	-55	-56	-57	-57	
-40	-51	-54	-56	-57	-59	-60	-61	-62	-63	-63	-64	
-45	-57	-60	-62	-64	-65	-66	-68	-69	-70	-70	-71	
-50	-63	-66	-68	-70	-72	-73	-74	-75	-76	-77	-78	

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4. CHOOSE CORRECT LEVEL OF PPE (personal protective equipment)

Responders
- ☐ LEVEL A
- ☐ LEVEL B
- ☐ LEVEL C
- ☐ LEVEL D

Decon Team
- ☐ LEVEL A
- ☐ LEVEL B
- ☐ LEVEL C
- ☐ LEVEL D

A	B	C	D	*Equipment Requirement (*depends on situation)*
x	x			SCBA (self-contained breathing apparatus) or positive pressure supplied air respirator with escape SCBA
		x		Full-face or half-face respirator with appropriate cartridges
		x	x	Escape mask*
x				Encapsulating suit (chemical protective with vapor barrier)
x	x	x		Outer gloves (chemically resistant)
x	x	x		Inner gloves (chemically resistant)
x	x	x	x	Boots (chemically resistant, steel-toe and shank)
x				Disposable protective suit worn over entire ensemble
x	x	x	x	Disposable outer boot covers, chemically-resistant*
x	x	x	x	Hard hat
	x	x	x	Face shield*
		x	x	Safety glasses or chemical splash goggles
x	x	x	x	Coveralls*
x	x	x	x	Hearing protection*
x	x	x	x	Personal flotation device*
x	x	x	x	Cold weather gear*

5. SPECIFY MONITORING REQUIREMENTS

Site Safety Officer or designee is responsible for monitoring the following parameters (indicated by checked boxes) at the appropriate frequency and for immediately communicating levels requiring action to the On-Scene Commander. Action levels based on TLVs published by ACGIH.

Parameter	*Frequency*	*Action Level*	*Required Action*
☐ Oxygen		<19.5%	Wear SCBA
		>23.5%	Fire potential; stop monitoring, leave area
☐ Flammable gas		≥10% LEL	Explosion hazard; leave area
☐ Benzene		>25 ppm	Wear SCBA
		0.5 - 25 ppm	Use full-face air purifying respirator with organic vapor cartridges
☐ Carbon dioxide		>50,000 ppm	Wear SCBA
		5,000 - 50,000 ppm	Use half-face air purifying respirator with appropriate cartridge
☐ Hydrocarbons		50 to 500 ppm	Use half-face air purifying respirator with appropriate cartridge
		>500 - 2,500 ppm	Use full-face air purifying respirator with appropriate cartridge

6. BRIEF ALL PERSONNEL

Site Diagram attached? ☐ Yes ☐ No

***Reviewed with all team members** (check all applicable items)*

- ☐ Buddy system
- ☐ Hazards / conditions on site
- ☐ Emergency hand signals
- ☐ Evacuation alarm
- ☐ Evacuation / escape route
- ☐ Criteria for immediate evacuation
- ☐ Radio communications
- ☐ Location of first aid/rescue gear
- ☐ Required PPE
- ☐ Safe access route to site

Prepared by Site Safety Officer — ***Approved by*** On-Scene Commander

Signature Date/Time Signature Date/Time

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7.0 MATERIAL/EQUIPMENT

MSDS

Refer to the MSDS binder is available at all control rooms at each plant location, and is updated every 3 years by the Health and Safety department. In the diesel plant for Aishihik, Whitehorse and Dawson, the MSDS binder is located in the Operators office.

PPE

Use/wear the appropriate PPE as recommended by the MSDS sheet. The appropriate PPE is mandatory.

Yukon energy operational locations and available equipment.

The following tables can be used during an inventory and faxed to the Environmental Coordinator or purchasing to purchase selected items

Location: Aishihik

Total Hydro and Diesel

Total Diesel:	10,000L
Total Oils:	1500L
Total varsol/glycol:	125L
Liquid natural gas	510m3
Natural Gas	2000m3
Gasoline	4500L

Container: **Large Spill kit behind garage (may be damaged)**

	Inventory Date: Oct 2013			
Quantity	**Description**			
		Size	**To Purchase**	**Date needed**
2	Plug n' Dike (Leak Repair Putty)	3"x3"		
2	Poly Spill pads containment sumps			
1	Hose wrap	24x24x2		
20	White Plastic enclose absorbent sheets	17.5x23		
20	White round oil absorbent sheets	21 1/2 x 21 1/2		
2	45 gallon drum lids	45 gallon		
3	Plastic lids			

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Location: Aishihik

Container: Spill Response Kit wheeled- Rocky Mountain

	Inventory Date: Oct 2013			
Quantity	**Description**	**Size**	**To Purchase**	**Date needed**
100	White Oil/Gas sheets	17"x19" ea		
6	White Oil/Gas Small pillows	8"x18"		
2	White Oil/Gas Large pillows	18"x18"		
5	White Oil/Gas only Socks	3"x8'		
2	White Oil/Gas only Socks	3"x4'		
1	Plug n' Dike (Leak Repair Putty)	1 lbs Jar		
1	Multi-Zorb Granular Sorbent	25lb bag		
1	Drain covers: Neoprene			
2	Yellow oil resistant Disposal Bag	33"x45"x6mil		
2	Gloves Nitrile	Pairs XL		
2	Splash Goggles	One fits all		
2	Disposable poly coated overalls	One fits all		

Location: Dawson

Total Diesel Plant only

Total Diesel: 131,735L
Total Oils: 5320L
Total varsol/glycol: 4035L
Liquid natural gas 0
Natural Gas 0

Inventory Date: Oct 2013

Location: Fuel Shack Dawson City

Container: Mobile Facility Spill Response Kit

Quantity	**Description**	**Size**	**To Purchase**	**Date needed**
1	Yellow Wheeled Container with Lid	240L		
1	Multi-Zorb Granular Sorbent	25lb bag		
100	Grey universal absorbent sheets	17"x19" ea		
2	Grey Universal Absorbent Sock	3"x 48"		
5	Grey Universal Absorbent Sock	3"x 96"		
5	Grey Universal Pillow	16"x16"		
25	White Oil/Gas only Absorbent sheets	17"x19" ea.		
1	Plug n' Dike (Leak Repair Putty)	1 lbs Jar		
6	Yellow oil resistant Disposal Bag	33"x45"x6mil		
3	Gloves Nitrile	Pairs XL		
3	Splash Goggles	One fits all		
3	Disposable Respirator	One fits all		

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Inventory Date: Oct 2013
Location: YM-1 Dawson City
Container: Spill Response Kit

Quantity	Description	Size	To Purchase	Date needed
1	HD oil/water resistant red nylon bag			
30	White Oil/Gas only Absorbent sheets	17”x19” ea.		
1	Plug n’ Dike (Leak Repair Putty)	1 lbs Jar		
2	Yellow oil resistant Disposal Bag	33”x45”x6mil		
1 box	Gloves Nitrile	Pairs XL		
2	Splash Goggles	One fits all		

Inventory Date: Oct 2013
Location: SC-1 Building Callison, Dawson
Container: Spill Response Kit

Quantity	Description	Size	To Purchase	Date needed
1	HD oil/water resistant red nylon bag			
15	Grey universal absorbent sheets	17"x19" ea		
2	White Oil/Gas only Absorbent sock	3”x 96”		
30	White Oil/Gas only Absorbent sheets	17”x19” ea.		
1	Plug n’ Dike (Leak Repair Putty)	1 lbs Jar		
2	Yellow oil resistant Disposal Bag	33”x45”x6mil		
1 box	Gloves Nitrile	Pairs XL		
2	Splash Goggles	One fits all		

Location: Faro

Glycol	5,100L
Diesel Fuel	112,250L
Oil	6,000L
Oil – Voltesso	12,900L

Inventory date: January 8 2014

Location: Faro FD1

Container: Spill Response Kit - Rocky Mountain Small, wheeled

Quantity	Description	Size	To Purchase	Date needed
1	White Oil/Gas sheets (bag of 100)	17"x19" ea		
6	White Oil/Gas Small pillows	8"x18"		
2	White Oil/Gas Large pillows	18"x18"		
5	Grey universal Socks	3"x8'		
2	Grey universal Socks	3"x4'		
2	Oil Boom	5"x10'		
1	Plug n' Dike (Leak Repair Putty)	1 lbs Jar		
1	Multi-Zorb Granular Sorbent	25lb bag		
2	Drain covers: Neoprene			
1 box	Gloves Nitrile	Pairs XL		
2	Splash Goggles	One fits all		
2	Disposable poly coated overalls	One fits all		
1	Disposal bags (6mil plastic) industrial waste	6mil plastic, box of 50		
1	Shovel, small foldable			
1	Meter tag on spill kit after restocked			
100	Grey sheets -full bag			
5	Grey pillows 8x8			

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Inventory date: January 8 2014

Location: Faro FD7

Container: Spill Response Kit - Large box Outside FD7 plant

Quantity	Description	Size	To Purchase	Date needed
1	White Oil/Gas sheets (bag of 100)	17"x19" ea		
20	White Oil/Gas Large pillows	18"x18"		
5	Grey universal Socks	3"x8'		
2	Grey universal Socks	3"x4'		
20-30	Oil Boom	5"x10'		
1	Plug n' Dike (Leak Repair Putty)	1 lbs Jar		
1	Multi-Zorb Granular Sorbent	25lb bag		
1	Drain covers: Neoprene			
1	Gloves Nitrile	Pairs XL		
2	Splash Goggles	One fits all		
2	Disposable poly coated overalls	One fits all		
2	Disposal bags (6mil plastic) industrial waste	6mil plastic		
1	Shovel			
1	Grey sheets -full bag	100 sheet bag		
5	Grey pillows 8x8			
1	Tarp			
1	Meter tag on spill kit after restocked			

Location: Mayo

Mayo Diesel Plant – Material amounts

Diesel Fuel	30,800L
Transformer Oil	2,380L
Engine oil	910L
Glycol	715L

Location: Mayo Diesel Plant

Container: Spill Response Kit - Rocky Mountain

Quantity	Description	Size	To Purchase	Date needed
1	HD oil/water resistant red nylon bag			
100	White Oil/Gas sheets	17"x19" ea		
6	White Oil/Gas Small pillows	8"x18"		
2	White Oil/Gas Large pillows	18"x18"		
5	White Oil/Gas only Socks	3"x8'		
2	White Oil/Gas only Socks	3"x4'		
1	Plug n' Dike (Leak Repair Putty)	1 lbs Jar		
1	Multi-Zorb Granular Sorbent	25lb bag		
1	Drain covers: Neoprene			
2	Yellow oil resistant Disposal Bag	33"x45"x6mil		
1 box	Gloves Nitrile	Pairs XL		
1	Splash Goggles	One fits all		
1	Disposable poly coated overalls	One fits all		

Location: Mayo A Hydro Plant

Plant Material amounts:

Oils 1,230L

Container: Spill Response Kit - Rocky Mountain

Quantity	Description	Size	To Purchase	Date needed
1	HD oil/water resistant red nylon bag			
100	White Oil/Gas sheets	17"x19" ea		
6	White Oil/Gas Small pillows	8"x18"		
2	White Oil/Gas Large pillows	18"x18"		
3	White Oil/Gas only Socks	3"x8'		
2	White Oil/Gas only Socks	3"x4'		
1	Plug n' Dike (Leak Repair Putty)	1 lbs Jar		
1	Multi-Zorb Granular Sorbent	25lb bag		
1	Drain covers: Neoprene			
2	Yellow oil resistant Disposal Bag	33"x45"x6mil		
1 box	Gloves Nitrile	Pairs XL		
2	Splash Goggles	One fits all		
2	Disposable poly coated overalls	One fits all		

Location: Mayo B Hydro Plant

Plant Material amounts:

Oils 1,230L

Container: Spill Response Kit - Rocky Mountain

Quantity	Description	Size	To Purchase	Date needed
1	HD oil/water resistant red nylon bag			
100	White Oil/Gas sheets	17"x19" ea		
6	White Oil/Gas Small pillows	8"x18"		
2	White Oil/Gas Large pillows	18"x18"		
5	White Oil/Gas only Socks	3"x8'		
2	White Oil/Gas only Socks	3"x4'		
1	Plug n' Dike (Leak Repair Putty)	1 lbs Jar		
1	Multi-Zorb Granular Sorbent	25lb bag		
1	Drain covers: Neoprene			
2	Yellow oil resistant Disposal Bag	33"x45"x6mil		
1 box	Gloves Nitrile	Pairs XL		
1	Splash Goggles	One fits all		
1	Disposable poly coated overalls	One fits all		

Location: Whitehorse

Total Hydro and Diesel

Total Diesel:	181,800L
Total Oils:	26800 L
Total varsol/glycol:	7400L
Liquid natural gas	510m3
Natural Gas	2000m3

Inventory done: Dec-13

Location: Whitehorse Diesel Plant -By Fuel Tank

Container: Spill Response Kit - Rocky Mountain

Quantity	Description	Size	To Purchase	Date needed
100	White Oil/Gas sheets	17"x19" ea		
6	White Oil/Gas Small pillows	8"x18"		
4	White Oil/Gas Large pillows	18"x18"		
5	White Oil/Gas only Socks	3"x8'		
3	White Oil/Gas only Socks	3"x4'		
6	Grey 3"x10' socks	3" x10'		
2	Grey 8"x8" pillows	8"x8"		
1	Plug n' Dike (Leak Repair Putty)	1 lbs Jar		
1	Multi-Zorb Granular Sorbent	25lb bag		
3	Drain covers: Neoprene			
2	Yellow oil resistant Disposal Bag	33"x45"x6mil		
2	Gloves Nitrile	Pairs XL		
2	Splash Goggles	One fits all		
2	Disposable poly coated overalls	One fits all		
1	Meter tag on spill kit after restocked			

Inventory done: Dec-13

Location: Whitehorse Hydro Plant

Container: Spill Response Kit - Rocky Mountain

Quantity	Description	Size	To Purchase	Date needed
100	White Oil/Gas sheets	17"x19" ea		
6	White Oil/Gas Small pillows	8"x18"		
2	White Oil/Gas Large pillows	18"x18"		
5	White Oil/Gas only Socks	3"x8'		
2	White Oil/Gas only Socks	3"x4'		
1	White Oil/Gas only Socks	3"x3"		
1	Multi-Zorb Granular Sorbent	25lb bag		
3	Drain covers: Neoprene			
2	Gloves Nitrile	Pairs XL		
2	Splash Goggles	One fits all		
2	Disposable poly coated overalls	One fits all		
1	Meter tag on spill kit after restocked			

Inventory done: Dec-13

Location: Whitehorse Spill trailer

Container: Spill Response Kit - Rocky Mountain

Quantity	Description	Size	To Purchase	Date needed
Safety Equipment/PPE				
1	Rain Suit			
1	Organics respirator			
1	Protective Goggles			
4	Rubber gloves, Latex 12"			
4	High visibility safety vests			
6	Pairs Rubber Boots			
12	Disposable Coveralls			
Containers/Absorbents				
1	White, Oily only Absorbent rolls (new)			
1	Absorbent rolls (open)			
1	150 Gallon pop-up pool			
1	20 gallon pop up pool			
1	3' by 3" absorbent sock			
1	33lb bag granular "floor dry"			
2	25lb bags granular oil absorbent			
3	Soild waste barrels, poly over packs			
1	ft 10'x4" boom (soiled)			
50	Rags			
1	Boom 10’ x8” (soiled, torn)			
1	ft 10'x8" boom (new)			

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Tools/Equipment				
1	Camera (disposable)			
1	Box road hazard triangles (3)			
1	Pick-axe			
1	Rake			
1	Shovel			
1	Push Broom			
1	Nylon hand broom			
1	4L container of solvent			
1	Plastic dust pan			
2	Spades			
2	100' bags poly rope			
3	Flashlights (replace batteries)			
4	Pylons			
1	Air Horn			
1	Fire extinguisher			
1	Pick			
Decontamination				
3	Drum plastic with removable lid	45 gal		

*Edits of this inventory will be catalogued and sent to the Environmental coordinator

8.0 EQUIPMENT/SERVICES

Table 1. Inventories/services supplied by contractor/consultant in the Whitehorse area

NAME	PHONE/ADDRESS	EQUIPMENT/SERVICES AVAILABLE	SERVICE AREA
Arctic Backhoe	334-1911	If spill containment needs external resources (Pumping out an existing, leaking tank) 1 large tank truck 2000 Gallon 1Small tank truck 300 Gallon Excavators Contaminated material treatment facility	Whitehorse/Southern lakes
Ajax	667-4800	Spill kits, sorbents, containment berms etc..	
Acklands Grainger	667-6660	Spill kits, sorbents, overpacks, spill trays	
Groundtrax Environmental	667-2515	Provides contaminated site assessment, and corrective action plan preparation services.	Whitehorse/Southern lakes
General Waste Management	668-4004	If spill containment needs external resources Carries inventory of Sorbents Crew available to clean up and mop up Capacity to dispose of contaminant Bobcats, tractors and trailers Vacuum service for hydro carbons	Whitehorse/Southern lakes
Laberge Environmental Services	1-405 Ogilvie St Whitehorse Y.T. Phone: (867) 668-6838 668-6838	Provides incident command, spill response, contaminated site assessment, and corrective action plan preparation services.	Yukon-wide
MacPherson Rentals	633-4426	Heavy equipment	
Petro Canada	110 Galena Rd Whitehorse Y.T. Phone: (867) 667-2468	Vacuum trucks	
Northwest Vacuum	667-7854	Vacuum trucks	
Sunset Septic	633-2907	Vacuum Trucks for fuel transfer	
Skookum Contracting	668-6326	Heavy equipment	
RC Crane	633-5755 334-5753	Crane equipment	
KBL Environmental	867-334-3455	Waste facility, LNG spill response	Whitehorse
SEEWOLF	867-993-6644	Spill response equipment	Dawson and Whitehorse

9.0 CONTACT DIRECTORY

Yukon Energy SCC **867-393-5324**
867-393-5355
800-676-2843

Emergency Services	**Fire**	**Ambulance**	**Police**
Dawson City	993-2222	993-4444	993-5555
Faro	994-2222	994-4444	994-5555
Mayo	996-2222	996-4444	996-5555
Whitehorse	911	911	911
Aishihik (Haines Junction)	634-2222	634-4444	634-5555

Yukon Energy Contacts

Yukon Energy Director of Operations	867-393-5317 (w) 867-334-8139 (cell) 867-456-7489 (h)
Yukon Energy Manager, SCC, Mechanical Operations	867-393-5366 (w) 867-334-6904 (cell) 867-668-4479 (h)
Yukon Energy Manager, Electrical Maintenance and T&D	867-393-5383(w) 867-334-6586 (cell) 867-668-6190 (h)
Yukon Energy Lead Hand, Transmission & Distribution	867-667-3607 (w) 867-334-1540 (cell)
Yukon Energy Lead Hand, Mechanical and Hydro Maintenance	867-393-5384 (w) 867-335-2863(cell) 867-667-6398 (h)
Yukon Energy Lead Hand, Electrical Maintenance	867-393-5374 (w) 867-334-2690 (cell) 867-633-5090 (h)
Yukon Energy Manager, Environment	867-393-5350 (w) 867-333-0300 (cell) 867-393-4866 (h)

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Yukon Energy Manager, Health and Safety	867-393-5353 (w) 867-334-2073 (h)

External Agency Contacts

Department of Environment, YTG, Whitehorse. Yukon	Phone: (867) 667-7244 (24 Hours) Fax: (867) 667-7962
Oil and Gas Resources	Toll Free: 1-800-661-0408 ext 5087
Oil and Gas Resources Chief Operations Officer	Phone: (867) 667-3565
CANUTEC National Advisory Centre offering advice On dangerous goods emergencies	Phone (613) 996-6666
Fire Marshall National Fire Code (fuel storage)	Phone: (867) 667-5417 (work)
City of Whitehorse Fire Chief	Phone: (867) 668-8383
Environmental Protection Act Spill Regulations	Phone: (867) 667-3436 (work)
Water Inspections Section Yukon Government Yukon Waters Act	Phone (867) 667-3227 (work)
Canadian Environmental Protection Agency Fisheries Act PCB Regulations	Phone (867) 667-3470 (work)
Department of Fisheries and Oceans Contact if spill or release into water	Phone (867)-393-6722
City of Whitehorse, Public Works, Manager Contact if spill or release in water or soil On City lands	Phone (867)-668-8351

10.0 SITE SPECIFIC INFORMATION: WHITEHORSE

The Facility

The Whitehorse Rapids Generating Station site is located on the Yukon River within the City of Whitehorse. It includes two hydro plants housing a total of four units with a total capacity of 40 MW, a diesel generation plant with a total of 10MW of diesel and a Natural Gas Generation plant with a total capacity of 8.8 MW. The diesel (WG0) and natural gas plants provide emergency backup and supplement the hydro plants in winter when the river flows are lower, during peak demand times and/or during an outage. The first two hydro units were placed in service in 1958 and a third unit was added in 1969. An additional power plant, housing a fourth unit, was constructed in 1985. Significant diesel fuel, liquid natural gas and lubricating oil volumes and a moderate amount of glycol and mercaptan for Natural Gas odourizing are in storage or in use at the site.

The Whitehorse Rapids GS facility includes the following structures:

- Two hydro power houses
- Main spillway
- Headworks structures and associated headgate structures / enclosure buildings
- Penstocks
- Diesel generating plant
- Natural Gas Plant
- Diesel fuel storage tank
- LNG Vapourization and Storage site
- Substation
- Switching station
- Corporate office building
- Fish ladder and fish weir, fish screens and underwater canal to direct fish to the ladder
- Other miscellaneous civil components such as access roads, parking areas and ancillary buildings.

The map on the following page (pg.18) shows the existing layout of the Yukon Energy's area at the Whitehorse Rapids Generating Facility.

To comply with Yukon's Gas Processing Plant Regulations (R-OGA-GPPR (NE)-13-FIN), Yukon Energy must:

- Immediately notify the Chief Operations Officer of the incident or near-miss.

- Submit to the Chief Operations Officer a final report regarding the incident or near miss within 45 days after the incident or near-miss occurred.

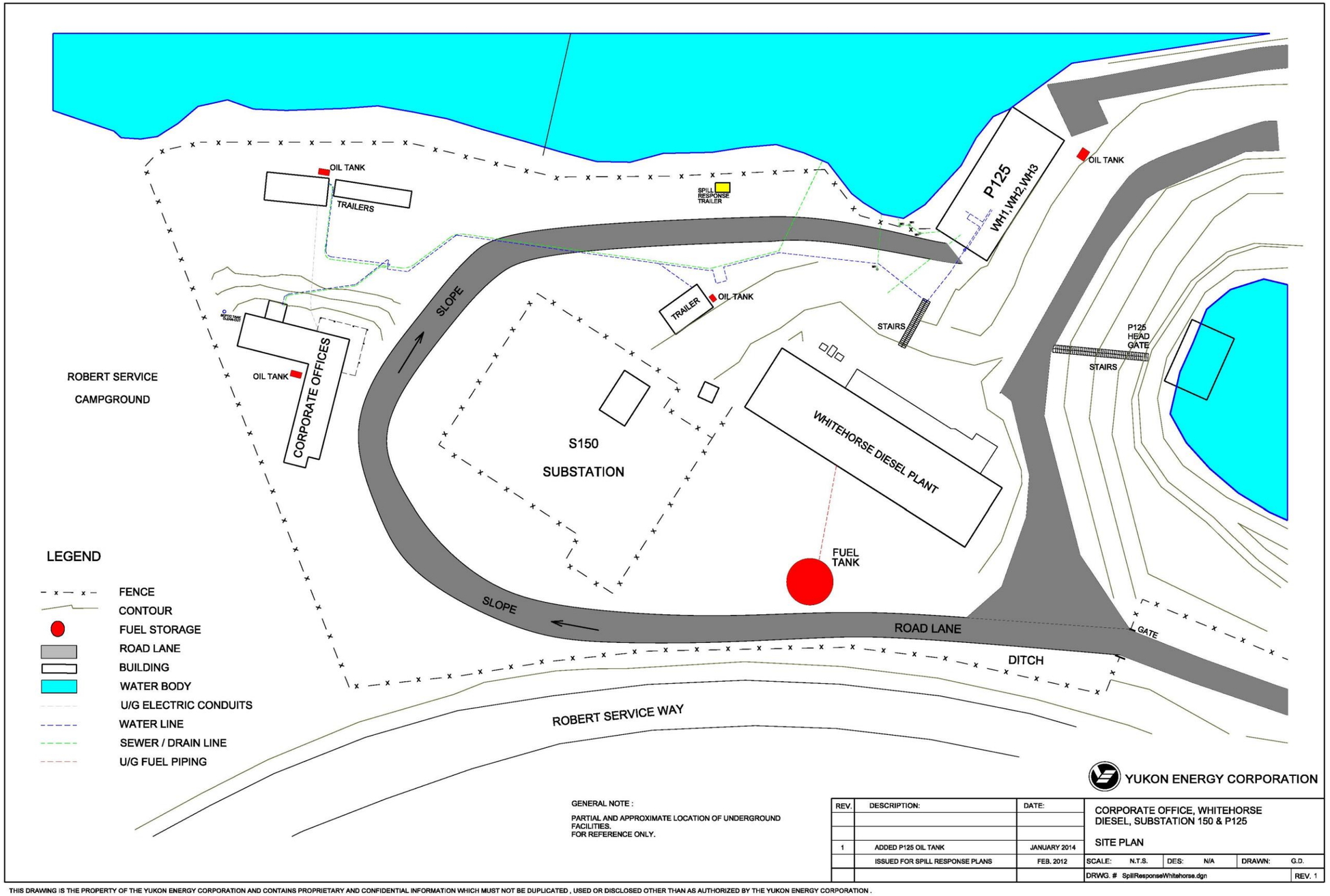
To comply with YEC's Water Use Licence for the Whitehorse Rapids Facility HY99-010;

- A detailed written report on any such spill event including, but not limited to, dates, quantities, parameters, causes and other relevant details and explanations, shall be submitted to the Board not later than 10 days after the occurrence, as well as included in the annual report.

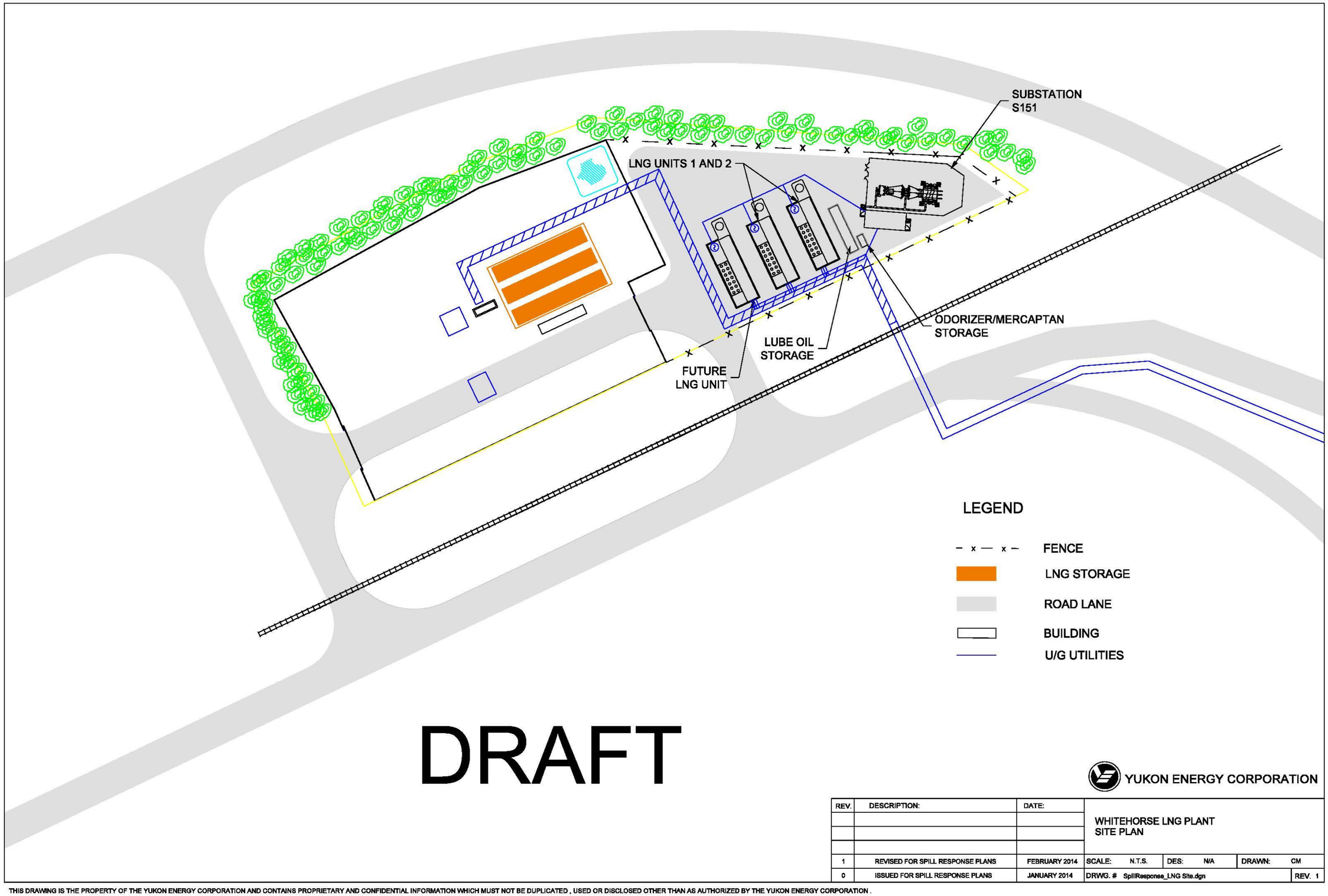
- YEC and its contractors shall maintain a log book of all spill or unauthorized discharge occurrences, including spills that are less than the reportable quantities under the Yukon *Spills Regulations.* The log book shall be made available at the request of the inspector. The log book shall include, but not necessarily be limited to:

- Date and time of the spill;
- Substance spilt or discharged;
- Approximate amount spilled or discharged;
- Distance between the spill or discharge and the nearest watercourse; and
- Remedial measures taken to contain and clean-up the spill area or to cease the discharge

These are written in the log book by the first responder, Lead Hand or Director of Operations depending on the severity of the spill. See page 6 for response organization structure.

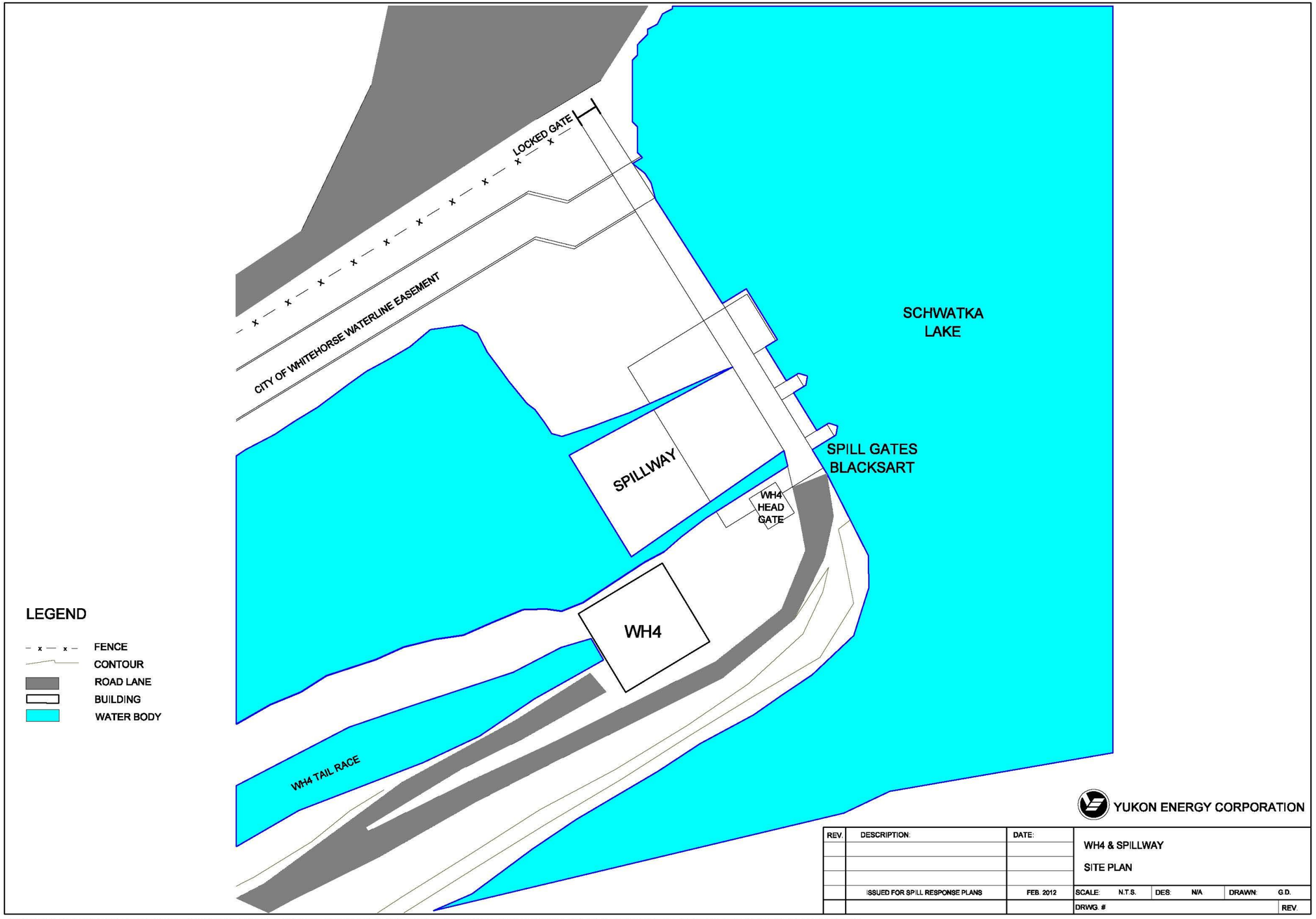


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REV.	DESCRIPTION:	DATE:	WHITEHORSE LNG PLANT SITE PLAN		
1	REVISED FOR SPILL RESPONSE PLANS	FEBRUARY 2014	SCALE: N.T.S.	DES: N/A	DRAWN: CM
0	ISSUED FOR SPILL RESPONSE PLANS	JANUARY 2014	DRWG. # SpillResponse_LNG Site.dgn		REV. 1

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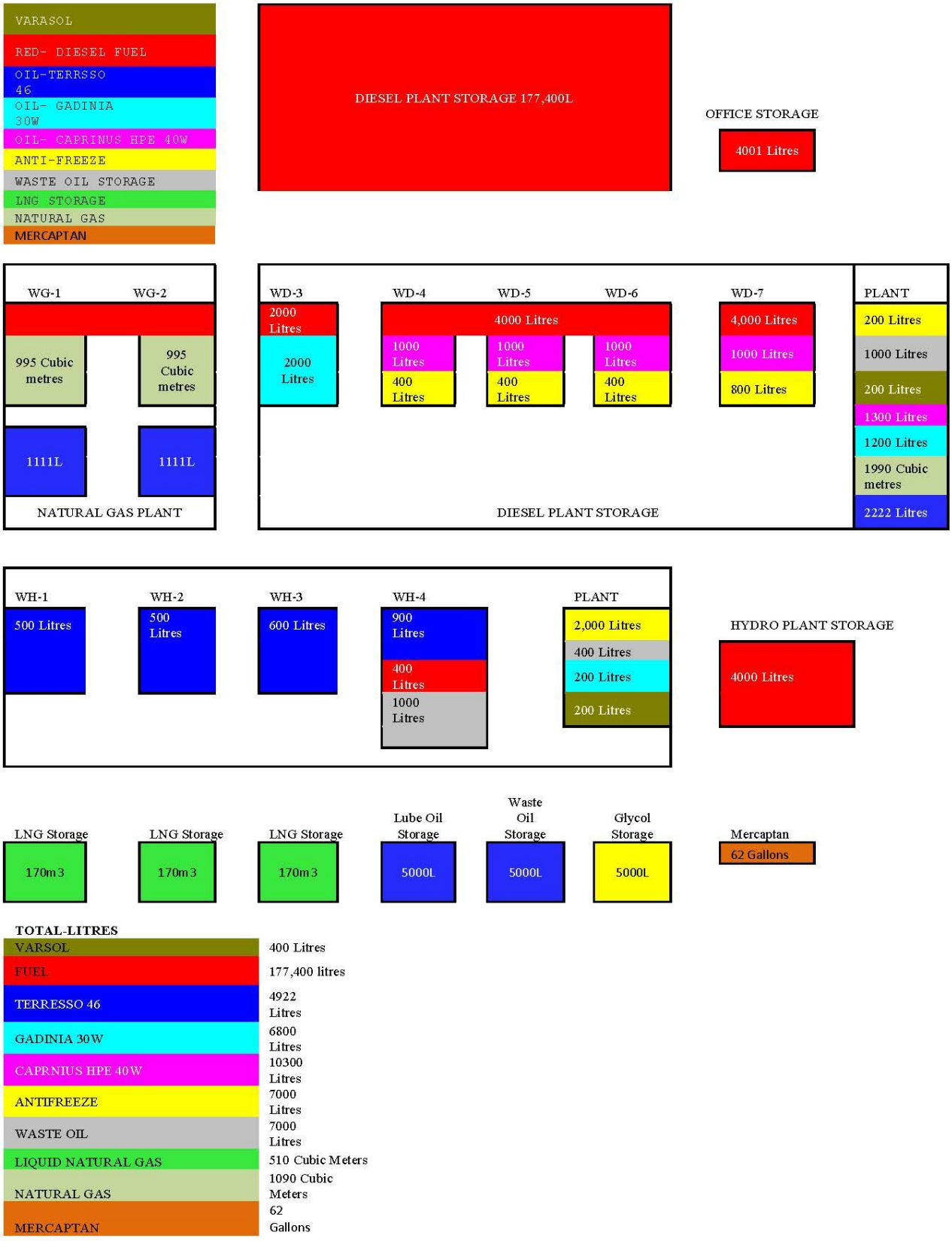
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Table 2. Fuel, Petroleum Product and other Hazardous Materials Brought On-Site or Generated On-Site

Hazardous Material Name	Est. Max. Amount of Material On-Site at Any One Time	Material Staging, Use, and Storage Location(s), & Material Storage and Secondary Containment Practices and Structures[1]	Distance of Material Staging, Use, and Storage Locations from Nearby Waterways[2] and Sensitive Areas[3]
Varsol	400L		60m
Diesel Fuel	177,400L	A concrete secondary containment berm was constructed around the main fuel tank	100m
Liquid Natural Gas	510m3	Three storage Tanks for LNG will be located at the storage and vaporization facility, at the expanded site area	80m to WH4 spillway, which is elevated with a dyke
Lube oil for Natural Gas Modules	5000L	Lube oil, used oil and Glycol tanks will be located next to the natural gas generators. Double wall tanks with alarms.	80m to WH4 spillway, which is elevated with a dyke
Used Oil storage for Natural Gas modules	5000L	Lube oil, used oil and Glycol tanks will be located next to the natural gas generators. Double wall tanks with alarms.	80m to WH4 spillway, which is elevated with a dyke
Glycol storage for Natural Gas modules	5000L	Lube oil, used oil and Glycol tanks will be located next to the natural gas generators. Double wall tanks with alarms.	80m to WH4 spillway, which is elevated with a dyke
Oil – Gadinia 30w	6,800L	Operators walk through the building once every 24 hours and visually check for spills in process.	60m
Oil – Caprinus HPE 40w	5,300L	Operators walk through the building once every 24 hours and visually check for spills in process.	60m
Anti-Freeze	2,000L	Operators walk through the building once every 24 hours and visually check for spills in process.	60m
Waste Oil Storage	2,000L	Operators walk through the building once every 24 hours and visually check for spills in process.	60m
Mercaptan	62.22 gallons	Leak proof assembly minimizes the possibility of, pressure gauge and levels checked once every 24 hours	60m

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Figure 2. Total Volumes of Hazardous Materials at the Whitehorse Generating Station



File location: https://sp2010.yec.yk.ca/Departments/env/ECW/Shared Documents/EMS/Spill Response Plans/Draft Spill Plans/FINAL

Figure 3. Sub-station S150 Oil

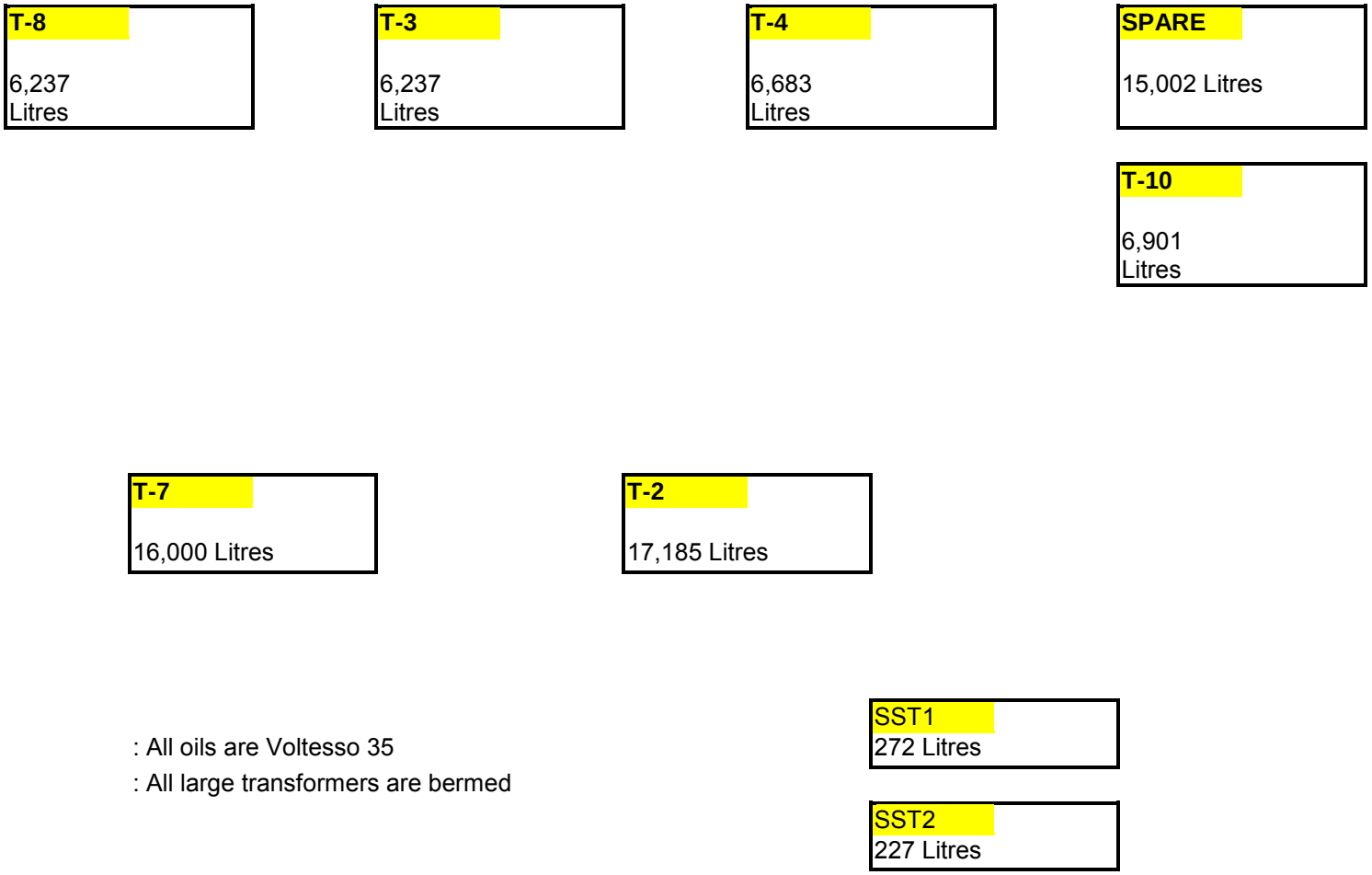
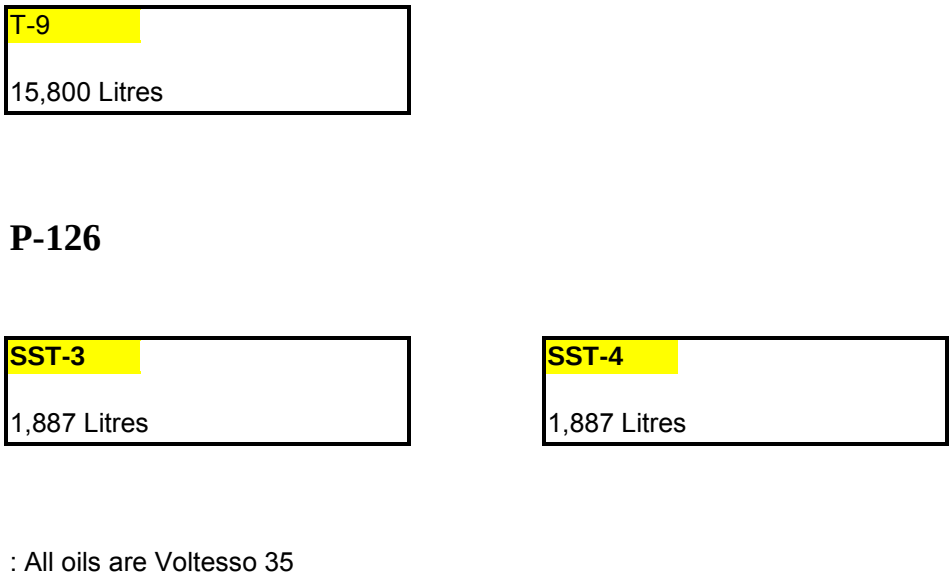


Figure 4. Whitehorse Hydro #4 Oil



11.0 RESOURCES AT RISK

Table 3. Site Description

A.	**Site Locations**	Diesel Plant Hydro Plant Natural Gas Plant Hydro electricity generation Fish Ladder Liquid Natural Gas Storage and Vapourization facility
B.	**The site location and boundaries:**	Whitehorse, Yukon, Canada. Yukon Energy Dam site
C.	**The drainage pathways from the site:**	Towards Millennium trail, north east side of property
D.	**Nearby waterways and sensitive areas and their distances from the site:**	Yukon River, City of Whitehorse Residents, millennium trail, Robert Service Campground

It is very unlikely that Yukon Energy would affect any water resources as mineral oils are used in the Hydro plant. As well sumps are located under the plant floors to intercept oils from going into the waterway.

12.0 SITE SPECIFIC SCENARIOS

SCENARIO 1

Oil alarm sounds for p126 in the Diesel Plant. Operator is called out to investigate. Oil is leaking from WD1 crankcase into the oil sump.

1. NOTIFY SUPERVISOR OR SSC

- Call SCC and Director of Operations
- Arrange Call-Back time, if appropriate.
- Incident commander will call all emergency response teams

2. ALERT OTHER EMPLOYEES/PERSONS IN AREA

- Approach spill site from up-wind or, if indoors, ensure you have a clear escape route
  - Check to make sure flow is turned off and safe to approach
  - Two operators are asked to start clean up around the sump
  - Create a barricade around the sump with spill response equipment located in the diesel spill kit.
  - Barricade area using safety flagging tape.
  - Get a crane in to remove sump grate, or use hooks
  - Get sorbent and clean up equipment situated bear the spill site (sump)
  - Confirm status with SCC – inform them of status
  - Continue with oil clean up
  - Stopping of water feed to engine and isolating all water leakage.
  - Start barricading with sorbent booms inside piping flooring
  - Inspection of water separator sump, located in p125 plant for oil – sorbent installed, manhole put back on
  - Monitor river bank to see if oil is present.
  - Inform SCC again on status. Oil has been contained and no leakage into the river
  - Isolate all possible sources of drainage into sump.
  - Obtain clearance with SCC to isolate WD1
  - Debrief with group
  - Contact Septic company to assist with cleanup – engine crankcase to be pumped out as well as surrounding piping area
  - Follow up inspection of oil separator outside P125 –clean up sorbent into plastic bags – reinstall manhole

- Commence documentation

USE BUDDY SYSTEM

3. IDENTIFY MATERIAL, SPILL SOURCE, ESTIMATE QUANTITY SPILLED AND POTENTIAL FATE

Block Potential Escape Routes, if appropriate

4. **IF SPILL CONTINUING, CONTROL SOURCE, IF SAFE TO DO SO**

   - Develop Initial Incident Response Plans (Defensive, Offensive or Non-Intervention)
   - Refer to product MSDS. Wear appropriate PPE.
     (See "Fast Fact Sheets" in this Plan for spills of specific products.)

5. **SUMMON RESPONSE RESOURCES, AS APPROPRIATE**

6. **UPDATE SUPERVISOR AND/OR SCC ON PROGRESS**

7. **COMPLETE DETAILED INCIDENT REPORT**

Table 4. Other Possible Scenarios

Hazardous Materials and Location	Spill Response Task			
	Assess the Spill	**Secure the Area**	**Contain and Eliminate the Spill Source**	**Clean Up Spilled Material Decontaminate Equipment Dispose of Spilled & Contaminated Material[1]**
Diesel Plant Storage – Mobilgard 312, Delvac 1340, Diesel, Varasol, Anti-Freeze	• Any considerable losses in the dip readings from one check to the next • Any fuel/lubricants smells or any pools on the floor	Inside the diesel plant	• Cover drains with the drain covers from the spill kit. • Use leak filler if leak is accessible and if it is safe to do so	• Use granular sorbents and sorbent sheets to mop up the spill • Hydrocarbon soiled materials will be disposed of in barrels and sealed. Barrels are located in the spill trailer. • Special waste is picked up is once a year by Environment Yukon
Waste oil	• Oil smells or any pools outside the waste oil containment	Outside the diesel plant in waste oil containment	• Use the spill kit located next to WD3 • Use oilwik boom around the spill site	• Use granular sorbents and sorbent sheets • Dig up the area to assess the extent of the spill • Place the contaminated soil in a poly lined temporary containment or a metal bin. • Attain a contaminated soil removal permit and transport to a land treatment facility
Any hazardous material	• See material flowing in the Whitehorse YEC yard	Cover the man holes immediately and contain the spill	• Use the Spill response trailer. Use man hole covers and a sorbent boom	• Clean up material with sorbents and discard appropriately
Liquid Natural Gas	• See rupture or leak • Hear alarm	Stop the leak IF SAFE TO DO SO Evacuate area Call fire department	• Let LNG evaporate to gas	• No clean up required as product turn into a gas
Mercaptan	• Indication of garlic smell of the mercaptan	Evacuate non-essential personnel	• Stop the release if safe to do so	• No clean up required as product is a gas

13.0 APPENDIX A: FORMS

ICS 201 –BREIFING DOCUMENT
ICS 214A – INDIVIDUAL LOG
Safe action/Initial Action Checklists by Substance

- **Diesel Fuel**
- **Liquid Natural Gas**
- **Natural Gas**
- **Delvac 1340**
- **Coolant- CAT EC-1 (238-8650)**
- **Mobilgard 312**
- **Teresso 46**
- **Varsol**
- **Waste Oil**
- **Voltesso 35**
- **SF6**
- **Mercaptan**

Appendix A1: **ICS 201-BRIEFING DOCUMENT**

Purpose. The Incident Briefing form provides the Incident Commander (YEC Site Supervisor) with basic information regarding the incident situation and the resources allocated to the incident. It also serves as a permanent record of the initial response to the incident.

Preparation. The briefing form is prepared by the Incident Commander (YEC Site Supervisor) for presentation to the incoming Incident Commander along with a more detailed oral briefing. Proper symbology should be used when preparing a map of the incident.

Distribution. After the initial briefing of the Incident Commander (YEC Site Supervisor) and General Staff members, the Incident Briefing is duplicated and distributed to the Command Staff, Section Chiefs, Branch Directors, Division/Group Supervisors, and appropriate Planning and Logistics Section Unit Leaders. The sketch map and summary of current action portions of the briefing form are given to the Situation Unit while the Current Organization and Resources Summary portion are given to the Resources Unit.

1. Incident Name:	2. Prepared by: Date: Time:	INCIDENT BRIEFING ICS 201-OS (pg 1 of 4)

3. Map/Sketch (include maps drawn here or attached, showing the total area of operations, the incident site/area, overflight results, trajectories, impacted shorelines, or other graphics depicting situational and response status)

INCIDENT BRIEFING	June 2000	ICS 201-OS (pg 1 of 4)

This document may have been revised since it was printed. **CONTROLLED DOCUMENT** – PRINTED COPIES MAY NOT BE CURRENT. CHECK THE EMS SHAREPOINT SITE FOR MOST CURRENT VERSION

1. Incident Name:	2. Prepared by: Date: Time:	INCIDENT BRIEFING ICS 201-OS (pg 2 of 4)

4. Initial Incident Objectives

5. Summary of Current Actions

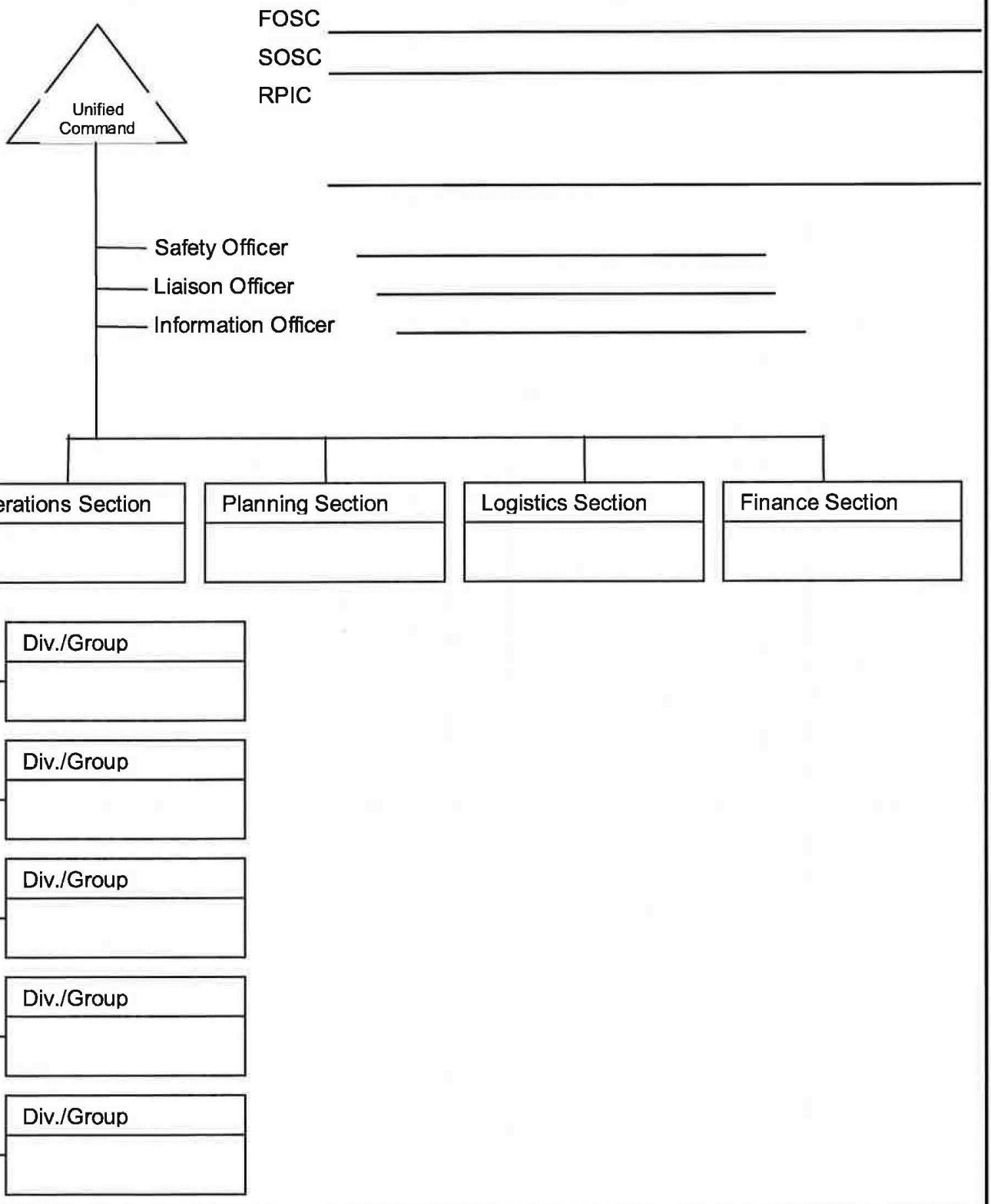
Time	Action/Note

INCIDENT BRIEFING June 2000 ICS 201-OS (pg 2 of 4)

This document may have been revised since it was printed. **CONTROLLED DOCUMENT** – PRINTED COPIES MAY NOT BE CURRENT. CHECK THE EMS SHAREPOINT SITE FOR MOST CURRENT VERSION

1. Incident Name:	2. Prepared by: Date: Time:	INCIDENT BRIEFING ICS 201-OS (pg 3 of 4)

3. Current Organization



INCIDENT BRIEFING	June 2000	ICS 201-OS (pg 3 of 4)

This document may have been revised since it was printed. **CONTROLLED DOCUMENT** – PRINTED COPIES MAY NOT BE CURRENT. CHECK THE EMS SHAREPOINT SITE FOR MOST CURRENT VERSION

1. Incident Name:	2. Prepared by: Date: Time:	INCIDENT BRIEFING ICS 201-OS (pg 4 of 4)

7. Resources Summary

Resources Needed	Time Ordered	Resources Identifier	ETA	On-Scene?	NOTES: (Location/Assignment/Status)

Appendix A2-: **ICS 214A – INDIVIDUAL LOG**

Purpose. The Unit Log is used to record details of unit activity including strike team activity. The file of these logs provides a basic reference from which to extract information for inclusion in any after-action report.

Initiation of Log. A Unit Log is initiated and maintained by head of the spill response effort.

1. Incident Name	2. Operational Period (Date / Time) From: To:	INDIVIDUAL LOG ICS 214a-OS
3. Individual Name	4. ICS Section	5. Assignment / Location

6. Activity Log		Page of
Time	Major Events	

7. Prepared by: **Date / Time**

INDIVIDUAL LOG June 2000 ICS 214a-OS

Record all personal activity --> Supervisor at end of shift --> Documentation Unit

Appendix A3-14: SAFE ACTION/INITIAL ACTION CHECKLISTS BY SUBSTANCE

Purpose. The purpose of the Safe Action/Initial Action Checklists by substance are to provide safety measures, PPE to be worn, first aid, emergency response, physical and chemical properties of a particular substance.

Use: These checklists are to be used as initial first action by the first responder.

Appendix A3: **DIESEL FUEL -SAFETY MEASURES**

- May cause eye, respiratory and skin irritation, headache, nausea, mental confusion, unconsciousness and death
    - Wear appropriate PPE
- Combustible liquid, may form explosive vapours
    - Eliminate ignition sources and monitor for combustible gases
- May accumulate static electricity
    - Ground and bond during transfers
- Vapours heavier than air
    - Stay out of low areas and confined spaces

Personal Protection

- If there is a high level of fumes during a spill, ventilate area before entering
- Wear required PPE, as appropriate

First Aid

- **Eyes**
    - Flush eyes immediately with fresh warm water (40C-45C) for at least 15 minutes holding lids open. DO NOT USE excessively hot or cold water
    - Get medical attention
- **Skin**
    - Remove contaminated clothing
    - Wash contaminated skin thoroughly with soap and warm water
    - Obtain medical attention if irritation or redness develops
- **Inhalation**
    - Move person to fresh air
    - Administer oxygen therapy, as necessary
    - WHEN OXYGEN IS IN USE, ENSURE NO SMOKING
- **Ingestion**
    - If swallowed, DO NOT INDUCE VOMITING and obtain immediate medical attention
    - Small amounts of materials that enter the mouth should be rinsed out until taste of substance is eliminated. Remove dentures and rinse well, if applicable

For Further Information Consult Product MSDS

Appendix A3: **DIESEL FUEL –EMERGENCY RESPONSE**

Spill

- Isolate area, restrict access and evacuate if necessary
- Eliminate ignition sources
- Advise SCC and/or Supervisor (867) 393 5324/ 393 5355
- Request assistance
- Attempt to limit escape routes and shut off source – IF SAFE TO DO SO
- Contain and recover using sorbent materials and/or vacuum truck

Fire

- Isolate area, restrict access and evacuate if necessary
- Call Fire Department, advise supervisor and/or SCC # (867) 393 5324/ 393 5355 to request assistance
- Shut off fuel to fire, IF SAFE TO DO SO
- If qualified, extinguish with dry chemical extinguisher, CO2, foam and/or H20 fog. DO NOT use a direct stream of water as it may spread the fire

Physical & Chemical Properties

Appearance:	Clear white to pale/bright yellow liquid
Odour:	Petroleum
Flashpoint:	Approximately > + 37.8C
Solubility in water:	Insoluble
Specific Gravity:	0.78 – 0.85
Vapour Density:	> than 1 (Air = 1)

For Further Information Consult Product MSDS

Appendix A4: **LIQUEFIED NATURAL GAS (LNG) – UN 1972 –SAFETY MEASURES**

(Will need to be updated with supplier's MSDS when available)

- May be fatal if swallowed and enters airways
- Causes skin irritation
- May cause drowsiness or dizziness
- Contact with gas or liquefied gas may cause burns, severe injury and/or frostbite
- Fire may produce irritating and/or toxic gases

PERSONAL PROTECTION

- Ensure use of proper personal protective equipment (PPE) at all times when handling this product, safety glasses or face shield, safety boots

FIRST AID

Eye Contact:

- If irritation or redness develops from exposure, flush eyes with clean water. If symptoms persist, seek medical attention.

Skin Contact:

- Remove contaminated clothing and flush affected area(s) with water.
- If skin surface is not damaged, cleanse affected area(s) thoroughly by washing with mild soap and water or a waterless hand cleaner.

Inhalation (Breathing):

- Move victim away from source of exposure and into fresh air
- If victim is not breathing, clear airway and immediately begin artificial respiration.
- If breathing difficulties develop, administer oxygen

Ingestion (Swallowing):

- Do not induce vomiting or give anything by mouth
- If victim is drowsy or unconscious and vomiting, place on the left side with the head down.
- Do not leave victim unattended

For further information refer to the product MSDS

Appendix A4: **LIQUID NATURAL GAS- EMERGENCY RESPONSE**

SPILL OR LEAK

- ISOLATE areas until gas has dispersed
- ELIMINATE all ignition sources
- Call Fire Department, advise supervisor and/or SCC # (867) 393 5324/ 393 5355 to request assistance
- Truck spill - Evacuate area up to 50m in all directions
- Large truck spill evacuate area for 300m (1000 ft)
- Spill from the facility evacuate area for 600m (2000ft) radius
- Use spark proof equipment
- Do not touch or walk through spilled material
- Stay upwind from spill or release.

FIRE

DO NOT EXTINGUISH FLAME UNTIL GAS FLOW IS SHUT OFF

- ISOLATE area, restrict access and evacuate if necessary
- ELIMINATE all ignition sources
- Turn off fuel to fire IF SAFE TO DO SO
- Call Fire Department, advise supervisor and/or SCC # (867) 393 5324/ 393 5355 to request assistance
- If a tank truck is involved in a fire evacuate area for 800 metres or 1/2 mile in all directions
- If qualified, extinguish with dry chemical extinguisher, CO2, foam and/or H20 fog to prevent fire from further spreading
- DO NOT use a direct stream of water as it may spread the fire

ALWAYS stay away from tanks involved in fire

PHYSICAL AND CHEMICAL PROPERTIES

Appearance:	Colourless
Odour:	Odourless
Flashpoint:	<-99^{o}C
Solubility in water:	Insoluble
Lower/Upper Explosive Limits:	No data
Vapour Density:	No data

For further information refer to the product MSDS

Appendix A5: **NATURAL GAS- SAFETY MEASURES**

- Natural Gas can displace oxygen causing asphyxiation and cause central nervous system (CNS) depression and cardiac sensitization
- Extremely flammable. Spillages of liquid product will create a fire hazard and may form an explosive atmosphere.
- Keep away from heat/sparks/open flames/hot surfaces. - No smoking.

PERSONAL PROTECTION

- Ensure use of proper personal protective equipment (PPE) at all times when handling this product,
- The use of eye/face protection is not normally required; however, good industrial hygiene practice suggests the use of eye protection that meets or exceeds ANSI Z.87.1 whenever working with chemicals.
- The use of skin protection is not normally required; however, good industrial hygiene practice suggests the use of gloves or other appropriate skin protection whenever working with chemicals.

FIRST AID

Eye Contact:
- If irritation or redness develops from exposure, flush eyes with clean water. If symptoms persist, seek medical attention.

Skin Contact:
- First aid is not normally required. However, it is good practice to wash any chemical from the skin.

Inhalation (Breathing):
- If respiratory symptoms develop, move victim away from source of exposure and into fresh air in a position comfortable for breathing. If breathing is difficult, oxygen or artificial respiration should be administered by qualified personnel. If symptoms persist, seek medical attention.

Ingestion (Swallowing):
- This material is a gas under normal atmospheric conditions and ingestion is unlikely.

For further information refer to the product MSDS

Appendix A5: **NATURAL GAS- EMERGENCY RESPONSE**

SPILL OR LEAK

INITIAL ACTION

- ISOLATE AREA, restrict access and evacuate if necessary
- Turn off leak source IF SAFE TO DO SO
- Call Fire Department, advise supervisor and/or SCC # (867) 393 5324/ 393 5355 to request assistance
- Truck release - Evacuate area up to 100m in all directions
- Facility release – Large spill evacuate personnel to 750m
- Keep all sources of ignition and hot metal surfaces away from spill/release if safe to do so.
- Beware of accumulation of gas in low areas or contained areas, where explosive concentrations may occur.
- Prevent from entering drains or any place where accumulation may occur.
- Ventilate area and allow to evaporate.
- Stay upwind and away from spill/release.

FIRE

DO NOT EXTINGUISH FLAME UNTIL GAS FLOW IS SHUT OFF

- ISOLATE AREA, restrict access and evacuate if necessary
- Turn off leak source IF SAFE TO DO SO
- Call Fire Department, advise supervisor and/or SCC # (867) 393 5324/ 393 5355 to request assistance
- For large fires, evacuate personnel within 750m radius.
- Use dry chemical, carbon dioxide, or foam fry extinguisher to prevent further spread of fire
- Stay away from ends of containers
- If release cannot be stopped, allow fire to burn
- Stay upwind from spill or release.
- Extremely flammable. This material can be ignited by heat, sparks, flames, or other sources of ignition (e.g., static electricity, pilot lights, mechanical/electrical equipment, and electronic devices such as cell phones, computers, calculators, and pagers which have not been certified as intrinsically safe).
- Vapors may travel considerable distances to a source of ignition where they can ignite, flash back, or explode. May create vapor/air explosion hazard indoors, in confined spaces, outdoors, or in sewers. If container is not properly cooled, it can rupture in the heat of a fire.

ALWAYS stay away from tanks involved in fire

PHYSICAL AND CHEMICAL PROPERTIES

Appearance:	Colourless
Odour:	Slight hydrocarbon
Flashpoint:	<-184^{o}C /-299 ^{o}F
Solubility in water:	Slight
Lower/Upper Explosive Limits (vol% in air):	2.0/10.0
Vapour Density (air=1):	0.5

Appendix A6: **DELVAC 1340- SAFETY MEASURES**

- Excessive exposure may result in eye, skin, or respiratory irritation. Wear appropriate PPE
- Material will not burn unless preheated. Avoid excessive heat as it may cause formation of vapours or mists in which case SCBA must be worn
    - Eliminate ignition sources
- Spilled material may create a slipping hazard

Personal Protection

- Wear required PPE, as appropriate

First Aid

- **Eyes**
    - Flush eyes immediately with fresh warm water (40C-45C) for 15 minutes holding lids open
    - Get medical attention if irritation occurs and persists
- **Skin**
    - Wash contaminated skin with mild soap and warm water. Remove contaminated clothing
    - Get medical attention if irritation occurs and persists
- **Inhalation**
    - Remove from further exposure.
    - For those providing assistance, avoid exposure to yourself or others. Use adequate respiratory protection.
    - If respiratory irritation, dizziness, nausea, or unconsciousness occurs, seek immediate medical assistance
    - WHEN OXYGEN IS IN USE, ENSURE NO SMOKING
- **Ingestion**
    - Not normally a factor.
    - If swallowed, DO NOT INDUCE VOMITING and get immediate medical attention
    - If vomiting occurs, keep the head low to prevent product entering the lungs

For Further Information Consult Product MSDS

Appendix A6: **DELVAC 1340- EMERGENCY RESPONSE**

Spill

- ISOLATE AREA, restrict access and evacuate if necessary
- Eliminate ignition sources
- Spill may create slipping hazard
- Advise Supervisor and/or SCC # (867) 393 5324/ 393 5355 to request assistance
- Attempt to limit product escape routes and shut off source – IF SAFE TO DO SO
- Contain and recover using sorbent materials and/or vacuum truck

Fire

- Evacuate and isolate area, restrict access
- Advise supervisor and/or SCC # (867) 393 5324/ 393 5355 to request assistance
- Shut off fuel to fire, IF SAFE TO DO SO
- If qualified, extinguish with dry chemical extinguisher, CO_2, foam and/or H_20 fog. DO NOT use direct stream of water as it may spread fire

Physical & Chemical Properties

Appearance:	Liquid. Brown
Odour:	Hydrocarbon odour
Flashpoint:	+ 230 C (446^{o}F)
Solubility in water:	Negligible
Specific Gravity:	< 1 (Water = 1)
Vapour Density:	Not available

For Further Information Consult Product MSDS

Appendix A7: **COOLANT- CAT EC-1 (238-8650) - SAFETY MEASURES**

- DO NOT taste or swallow antifreeze. DO NOT breathe vapours or fumes
    - Wear appropriate PPE
- Material is unlikely to burn unless preheated
- It may possibly accumulate static electricity
    - Ground and bond containers during transfer

Personal Protection

- If high level of fumes are present during a spill, ventilate area before entering
- Wear other required PPE, as appropriate

First Aid

- **Eyes**
    - Flush eyes immediately with fresh warm water (40C-45C) for 15 minutes holding lids open
    - Obtain medical attention if irritation persists
- **Skin**
    - Wash contaminated area with plenty of mild soap and water. Remove contaminated clothing
    - If irritation occurs and persists, obtain medical attention
- **Inhalation**
    - Move exposed person to fresh air
    - Administer oxygen therapy, as necessary and only if trained
    - WHEN OXYGEN IS IN USE, ENSURE NO SMOKING
    - If symptoms occur, obtain medical attention
- **Ingestion**
    - Remove dentures, if any, and rinse. Rinse out mouth until taste of product dissipates
    - If swallowed, DO NOT INDUCE VOMITING. Get immediate medical attention
    - If vomiting occurs, keep the head low to prevent product entering the lungs.

For Further Information Consult Product MSDS

Appendix A7: **COOLANT- CAT EC-1 (238-8650) - EMERGENCY RESPONSE**

Spill

- ISOLATE area, restrict access and evacuate if necessary
- Eliminate ignition sources though substance unlikely to ignite
- Advise Supervisor and/or SCC # (867) 393 5324/SCC Cell. (867) 393 5355
- Request assistance
- Attempt to limit product escape routes and shut off source – IF SAFE TO DO SO
- Contain and recover using appropriate sorbent materials and/or vacuum truck

Fire

- Isolate area, restrict access and evacuate if necessary
- Advise supervisor and/or SCC # (867) 393 5324/ 393 5355 to request assistance
- Shut off fuel to fire, IF SAFE TO DO SO
- If qualified, extinguish with dry chemical extinguisher, CO_2, foam and/or H_20 fog
  DO NOT use a direct stream of water as it may spread fire

Physical & Chemical Properties

Appearance:	Liquid. Yellow Colour
Odour:	Faint or mild
Flashpoint:	+ 127 C
Solubility in water:	Soluble
Lower/Upper Explosive Limits:	Lower 3.2% Upper: Not stated
Vapour Density:	2.1 (Air = 1)

For Further Information Consult Product MSDS

Appendix A8: **MOBILGARD 312 – SAFETY MEASURES**

- Excessive exposure may result in eye, skin, or respiratory irritation.
- Exposure most likely to occur through skin contact or from inhalation of mechanically or thermally generated oil mists. Normally, product has a low level of toxicity
    - Wear appropriate PPE
- Material will not burn unless preheated. Avoid excessive heat as it may cause formation of vapours or mists
    - Eliminate ignition sources
- Spilled material may create a slipping hazard

Personal Protection

- If high level of fumes are present during a spill, ventilate area before entering
- Wear other required PPE, as appropriate
- If contact is likely with eyes, then safety glasses should be worn.

First Aid

- **Eyes**
    - Flush eyes immediately with fresh warm water (40C-45C) for 15 minutes holding lids open
    - Get medical attention if irritation occurs and persists
- **Skin**
    - Wash contaminated skin with mild soap and water. Remove contaminated clothing
    - Get medical attention if symptoms occur and persist
- **Inhalation**
    - Move exposed person to fresh air
    - Administer oxygen therapy, as necessary and only if trained
    - WHEN OXYGEN IS IN USE, ENSURE NO SMOKING
- **Ingestion**
    - Remove dentures, if any. Wash out mouth with water. Substance has low oral toxicity
    - First Aid is normally not required. Seek medical attention if discomfort occurs

For Further Information Consult Product MSDS

Appendix A8: **MOBILGARD 312 – EMERGENCY RESPONSE**

Spill

- Isolate area, restrict access and evacuate if necessary
- Eliminate ignition sources
- Spill may create slipping hazard
- Advise supervisor and/or SCC # (867) 393 5324/ 393 5355 to request assistance
- Request assistance
- Attempt to limit product escape routes and shut off source – IF SAFE TO DO SO
- Contain and recover using sorbent materials and/or vacuum truck

Fire

- Isolate area, restrict access and evacuate if necessary
- Call Fire Department, advise supervisor and/or SCC # (867) 393 5324/ 393 5355 to request assistance
- Shut off fuel to fire, IF SAFE TO DO SO
- If qualified, extinguish with dry chemical extinguisher, CO_2, foam and/or H_20 fog. DO NOT use direct stream of water as it may spread the fire

Physical & Chemical Properties

Appearance:	Liquid. Brown colour
Odour:	Hydrocarbon odour
Flashpoint:	> + 225 C (437 F)
Solubility in water:	Insoluble
Specific Gravity:	< 1 (Water = 1)
Vapour Density:	Not available

For Further Information Consult Product MSDS

Appendix A9: **TERESSO 46 – SAFETY MEASURES**

- Low order of toxicity. Excessive exposure may result in eye, skin or respiratory inhalation
    - Wear appropriate PPE
- Material will not burn unless preheated. Avoid excessive heat as it may cause formation of vapors or mists
    - Eliminate ignition sources
- Spilled material may create a slipping hazard

Personal Protection

- If high levels of fumes are present during the event of a spill, ventilate area before entering
- Wear other required PPE, as appropriate

First Aid

- **Eyes**
    - Flush eyes immediately with fresh water (40C-45C) for 15 minutes holding lids open. DO NOT USE excessively hot or cold water
    - Get medical attention if irritation occurs
- **Skin**
    - Wash contaminated skin with mild soap and water. Remove contaminated clothing
    - Get medical attention if symptoms occurs or the substances comes in contact with an open wound
- **Inhalation**
    - Move exposed person to fresh air
    - Administer oxygen therapy, as necessary and only if trained
    - WHEN OXYGEN IS IN USE, ENSURE NO SMOKING
- **Ingestion**
    - First aid is not normally required. Seek medical attention if discomfort occurs
    - Remove dentures, if any, and rinse before replacing. Rinse out mouth with water until taste of product dissipates. Substance has low oral toxicity

For Further Information Consult Product MSDS

Appendix A9: **TERESSO 46 – EMERGENCY RESPONSE**

Spill

- Isolate area, restrict access and evacuate if necessary
- Eliminate ignition sources
- Spill may create slipping hazard
- Advise supervisor and/or SCC # (867) 393 5324/ 393 5355 to request assistance
- Attempt to limit product escape routes and shut off source – IF SAFE TO DO SO
- Contain and recover using sorbent materials and/or vacuum truck

Fire

- Isolate area, restrict access and evacuate if necessary
- Call Fire Department, advise supervisor and/or SCC # (867) 393 5324/ 393 5355 to request assistance
- Shut off fuel to fire, IF SAFE TO DO SO
- If qualified, extinguish with dry chemical extinguisher, CO_2, foam and/or H_20 fog. DO NOT use direct stream of water as it may spread fire

Physical & Chemical Properties

Appearance:	Liquid. Amber in colour
Odour:	Lubricating oil odour
Flashpoint:	+ 200 C
Solubility in water:	Negligible
Specific Gravity:	< 1 (Water = 1)
Vapour Density:	> 2 (Air = 1)

For Further Information Consult Product MSDS

Appendix A10: **VARSOL – SAFETY MEASURES**

- May cause mild irritation to eyes and skin upon contact, drowsiness, lack of coordination, headache and nausea.
    - Wear appropriate PPE
- Combustible liquid. May form explosive vapours. Use in adequately ventilated area
    - Eliminate ignition sources
- Vapours heavier than air
    - Stay out of low areas and confined spaces
- May accumulate static electricity
    - Ground and bond containers during transfer

Personal Protection

- If high level of fumes are present during a spill, ventilate area before entering
- Wear other required PPE, as appropriate

First Aid

- **Eyes**
    - Flush eyes immediately with fresh warm water (40C-45C) for 15 minutes holding lids open
    - Get medical attention if irritation occurs
- **Skin**
    - Flush contaminated skin with plenty of water. Remove contaminated clothing
    - Get medical attention if symptoms occur
- **Inhalation**
    - Move exposed person to fresh air
    - Administer oxygen therapy, as necessary and only if trained
    - WHEN OXYGEN IS IN USE, ENSURE NO SMOKING
    - Get medical attention if adverse health effects persist or are severe
- **Ingestion**
    - Remove dentures, if any, and rinse with water. Rinse out mouth with water
    - Obtain medical attention if symptoms occur
    - If swallowed, DO NOT INDUCE VOMITING. Give small quantities of water or milk to drink and get immediate medical attention
    - If vomiting occurs, keep the head low to prevent product entering the lungs

For Further Information Consult Product MSDS

Appendix A10: **VARSOL – EMERGENCY RESPONSE**

Spill

- Isolate area, restrict access and evacuate if necessary
- Eliminate ignition sources
- Advise Supervisor and/or SCC # (867) 393 5324/. (867393 5355
- Request assistance
- Attempt to limit product escape routes and shut off source – IF SAFE TO DO SO
- Contain and recover using sorbent materials and/or vacuum truck

Fire

- Isolate area, restrict access and evacuate if necessary
- Call Fire Department, advise supervisor and/or SCC # (867) 393 5324/ 393 5355 to request assistance
- Shut off fuel to fire, IF SAFE TO DO SO
- If qualified, extinguish with dry chemical extinguisher, CO_2, foam and/or H_20 fog. DO NOT use direct stream of water as it may spread fire

Physical & Chemical Properties

Appearance:	Clear liquid
Odour:	Petroleum distillate
Flashpoint:	> + 37.8 C (Combustible liquid)
Solubility in water:	Insoluble
Lower/Upper Flammability Limits:	1% - 13%
Vapour Density:	5 (Air = 1)

For Further Information Consult Product MSDS

Appendix A11: **VOLTESSO 35 - SAFETY MEASURES**

- May cause eye, respiratory and skin irritation. Frequent or prolonged contact may de-fat and dry the skin
    - Wear appropriate PPE
- Combustible liquid, may form explosive vapours
    - Eliminate ignition sources and monitor for combustible gases
- May accumulate static electricity
    - Ground and bond during transfers
- Vapours heavier than air
    - Stay out of low areas and confined spaces

Personal Protection

- If high level of fumes are present during a spill, ventilate area before entering
- Wear other required PPE, as appropriate

First Aid

- **Eyes**
    - Flush eyes immediately with fresh warm water (40C-45C) for at least 15 minutes holding lids open. DO NOT USE excessively hot or cold water
    - Get medical attention
- **Skin**
    - Remove contaminated clothing
    - Wash contaminated skin thoroughly with soap and warm water
    - Obtain medical attention if irritation or redness develops
    - Launder contaminated clothing before reuse
- **Inhalation**
    - Move person to fresh air
    - Administer oxygen therapy, as necessary and only if trained
    - WHEN OXYGEN IS IN USE, ENSURE NO SMOKING
- **Ingestion**
    - If swallowed, DO NOT INDUCE VOMITING and obtain immediate medical attention
    - Small amounts of materials that enter the mouth should be rinsed out until taste of substance is eliminated. Remove dentures and rinse well, if applicable

For Further Information Consult Product MSDS

Appendix A11: **VOLTESSO 35–EMERGENCY RESPONSE**

Spill

- Isolate area, restrict access and evacuate if necessary
- Eliminate ignition sources
- Advise Supervisor and/or SCC (867) 393 5324/ 867 393 5355 to request assistance
- Attempt to limit escape routes and shut off source – IF SAFE TO DO SO
- Contain and recover using sorbent materials and/or vacuum truck

Fire

- Isolate area, restrict access and evacuate if necessary
- Call Fire Department, advise supervisor and/or SCC # (867) 393 5324/ 393 5355 to request assistance
- Shut off fuel to fire, IF SAFE TO DO SO
- If qualified, extinguish with dry chemical extinguisher, CO2, foam and/or H20 fog. DO NOT use a direct stream of water as it may spread the fire

Physical & Chemical Properties

Appearance:	Pale Yellow, liquid
Odour:	N/D
Flashpoint:	Approximately > 145C
Solubility in water:	Negligible
Specific Gravity:	-
Vapour Density:	> N/D (Air = 1)

For Further Information Consult Product MSDS

Appendix A12: **SF6 GAS- SAFETY MEASURES**

- May cause eye, respiratory and skin irritation. Frequent or prolonged contact may de-fat and dry the skin
- Escaping gas may cause frostbite injury
    - Wear appropriate PPE
    - Eliminate ignition sources and monitor for combustible gases
- May accumulate static electricity
    - Ground and bond during transfers
- Vapours heavier than air
    - Stay out of low areas and confined spaces

Personal Protection

- General mechanical ventilation must be worn
- Ribber gloves
- ANSI approved Chemical Workers Goggles
- Coveralls

First Aid

- **Eyes**
    - Flush eyes immediately with fresh warm water (40C-45C) for at least 15 minutes holding lids open. DO NOT USE excessively hot or cold water
    - Get medical attention if pain or sensitivity to light persists
- **Skin**
    - Wash exposed area extremely thouroughly, but gently in cases of frostbite –like injury, with soap and water
- **Inhalation**
    - Move person to fresh air
    - Administer oxygen therapy, as necessary and only if trained
    - WHEN OXYGEN IS IN USE, ENSURE NO SMOKING
- **Ingestion**
    - If swallowed, DO NOT INDUCE VOMITING and obtain immediate medical attention
    - Contact MD immediately

For Further Information Consult Product MSDS

Appendix A12: **SF6 GAS –EMERGENCY RESPONSE**

Spill

- Evacuate personnel to safe areas. Wear PPE and self-contained breathing apparatus when entering area unless atmosphere is proved to be safe. Ventilate the area. Monitor oxygen level
- Stay upwind
- If possible, stop the flow of product
- Advise Supervisor and/or SCC (867) 393 5324/ 867 393 5355 Request assistance

Fire

- Isolate area, restrict access and evacuate if necessary
- Call Fire Department, advise supervisor and/or SCC # (867) 393 5324/ 393 5355 to request assistance
- Shut off fuel to fire, IF SAFE TO DO SO
- If qualified, extinguish with dry chemical extinguisher, CO2, foam and/or H20 fog. DO NOT use a direct stream of water as it may spread the fire

For Further Information Consult Product MSDS

Appendix A13: **WASTE OIL – SAFETY MEASURES**

- Mixture of water, oil and lubricant additives. Concentrations of components will vary. The product is not expected to be irritating and has a low level of toxicity under normal use. Exposure most likely to occur through skin or eye contact
    - Wear appropriate PPE
    - Spill may create slipping hazard
- Material is unlikely to burn unless preheated. Spilled material may produce a slipping hazard
    - Vapour pressure will vary dependent on the composition
- It may possibly accumulate static electricity
    - Ground and bond containers during transfer

Personal Protection

- If high level of fumes are present during a spill, ventilate area before entering
- Wear other required PPE, as appropriate

First Aid

- **Eyes**
    - Flush eyes immediately with fresh warm water (40C-45C) for 15 minutes holding lids open
    - Get medical attention if irritation persists
- **Skin**
    - Wash contaminated area with plenty of mild soap and water for 15 minutes. Remove contaminated clothing
    - If irritation occurs and persists, obtain medical attention
- **Inhalation**
    - Move exposed person to fresh air. Additional First Aid treatment is not usually required
    - Administer oxygen therapy, if necessary and/or obtain medical assistance
    - WHEN OXYGEN IS IN USE, ENSURE NO SMOKING
- **Ingestion**
    - Remove dentures, if any, and rinse with water. Rinse out mouth with water
    - If swallowed, DO NOT INDUCE VOMITING. Get immediate medical attention
    - If vomiting occurs, keep the head low to prevent product entering the lungs. Obtain medical attention

For Further Information Consult Product MSDS

Appendix A13: **WASTE OIL – EMERGENCY RESPONSE**

Spill

- Isolate area, restrict access and evacuate if necessary
- Eliminate ignition sources though substance unlikely to ignite
- Spilled material make create a slipping hazard
- Advise Supervisor and/or SCC # (867) 393 5324/ (867) 393 5355
- Request assistance
- Attempt to limit product escape routes and shut off source – IF SAFE TO DO SO
- Contain and recover using appropriate sorbent materials and/or vacuum truck

Fire

- Isolate area, restrict access and evacuate if necessary
- Call Fire Department, advise supervisor and/or SCC # (867) 393 5324/ 393 5355 to request assistance
- Shut off fuel to fire, IF SAFE TO DO SO
- If qualified, extinguish with dry chemical extinguisher, CO_2, foam and/or H_20 fog. DO NOT use a direct stream of water as it may spread fire

Physical & Chemical Properties

Appearance:	Liquid. Colour will vary depending on composition
Odour:	Hydrocarbon
Flashpoint:	Will vary depending on composition. Unlikely to burn
Solubility in water:	Insoluble
Lower/Upper Explosive Limits:	Will vary
Vapour Density:	Will vary

For Further Information Consult Product MSDS

Appendix A14: **BUTYL MERCAPTAN – SAFETY MEASURES**

- Extremely flammable liquid and vapour.
- Vapour is heavier than air
- Vapors and gases may ignite at distant ignition sources and flash back. Vapor/air mixtures are explosive
- Vapour may cause flash fire. Contact with water or moist air may generate flammable and/or toxic gases.
- Central nervous system depression

Personal Protection

- In the event of a spill, ventilation equipment should be explosion-resistant if explosive concentrations of material are present.
- Wear splash resistant safety goggles.
- Wear chemical resistant gloves and clothing

First Aid

- **Eyes**
  - Flush eyes immediately with fresh warm water (40C-45C) for 15 minutes holding lids open
  - Get medical attention if irritation persists

- **Skin**

  - Wash skin with soap and water for at least 15 minutes while removing contaminated clothing and shoes. Get medical attention, if needed.
  - Thoroughly clean and dry contaminated clothing and shoes before reuse.

- **Inhalation**

  - If adverse effects occur, remove to uncontaminated area. Give artificial respiration if not breathing. If breathing is difficult, oxygen should be administered by qualified personnel. Get immediate medical attention.

- **Ingestion**

  - If a large amount is swallowed, get medical attention.
  - Causes irritation, sore throat, nausea, stomach pain, headache, drowsiness, dizziness, loss of coordination

For Further Information Consult Product MSDS

Appendix A14: BUTYL MERCAPTAN – EMERGENCY RESPONSE

Spill

- ISOLATE AREA, restrict access and evacuate if necessary
- Turn off leak source IF SAFE TO DO SO
- Call Fire Department, advise supervisor and/or SCC # (867) 393 5324/ 393 5355 to request assistance
- Keep all sources of ignition and hot metal surfaces away from spill/release if safe to do so.
- Reduce vapors with water spray.
- Small spills: Absorb with sand or other non-combustible material.
- Collect spilled material in appropriate leak proof container for disposal.
- Large spills: Dike container for later disposal. Remove sources of ignition. Keep unnecessary people away, isolate hazard area and deny entry.

Fire

- ISOLATE AREA, restrict access and evacuate if necessary
- Call Fire Department, advise supervisor and/or SCC # (867) 393 5324/ 393 5355 to request assistance
- For tank, rail car or tank truck fire, evacuation radius: 800 meters (1/2 mile).
- Do not attempt to extinguish fire unless flow of material can be stopped first.
- Use regular dry chemical;, carbon dioxide, water, regular foam
- Move container from fire area, IF SAFE TO DO SO
- Dike container for later disposal.
- Do not scatter spilled material with high-pressure water streams. Cool containers with water spray until well after the fire is out. Stay away from the ends of tanks. Withdraw immediately in case of rising sound from venting safety device or any discoloration of tanks due to fire.
- Avoid inhalation of material or combustion by-products. Stay upwind and keep out of low areas.

Physical & Chemical Properties

Appearance:	Gas. Colourless
Odour:	Skunk–like or Garlic Odor
Flashpoint:	-48.4 C (-54.9 F)
Water solubility:	6.7% @20C (reacts)
Lower/Upper Explosive Limits:	L 2.8%, U 18%,
Vapour Density:	2.14
Specific gravity (water=1):	0.83 @25C

For Further Information Consult Product MSDS

This document may have been revised since it was printed. **CONTROLLED DOCUMENT –** PRINTED COPIES MAY NOT BE CURRENT. CHECK THE EMS SHAREPOINT SITE FOR MOST CURRENT VERSION

14.0 WASTE MANAGEMENT

All equipment and/or material used in clean-up (e.g. used sorbents, oil containment materials etc.) must be disposed of in accordance with Environment Yukon requirements.

Accidental spills may produce special wastes (e.g., material with > 3% used oil) and contaminated soil. All waste disposal must comply with the *Yukon Special Waste Regulations* of the *Yukon Environment Act.*

Compliance with these regulations generally requires:

- Classification of the waste
- Packaging requirements (proper labeling and suitable storage containers)
- Transportation documentation
- All transporters must be properly trained
- Disposal in accordance with the regulations at an appropriate facility
- Spill reporting requirements must also be followed
- Waste sorbent material may not be disposed of in a landfill without prior approval from YTG Environment and the landfill operator.
- Contaminated soil must be treated and dealt with as required on a site specific basis and must comply with the requirements of the Yukon Contaminated Sites and Special Waste Regulations. At a minimum, the contractor must consider soil relocation agreement standards and obtain soil relocation permit as required.

Specific clean up requirements

Fuels and lubricants/Waste oil

After clean up, soiled sorbent materials will be placed inside an over pack or sealed metal drums and contained securely until organized special waste disposal can be coordinated.

Liquid wastes will be contained in a separate over pack or sealed metal drum.

Contaminated soils will be removed by an authorized contaminated soil receptor and transported to a land treatment facility.

Liquid Natural Gas

Methods for Containment and Clean-Up: Notify relevant authorities in accordance with all applicable regulations. Immediate cleanup of any spill is recommended. Dike far ahead of spill for later recovery or disposal. Absorb spill with inert material such as sand or vermiculite, and place in suitable container for disposal. If spilled on water remove with appropriate methods (e.g.skimming, booms or absorbents). In case of soil contamination, remove contaminated soil for remediation or disposal, in accordance with local regulations.

Mercaptan

Leaking containers after a release should be stored in a cool, dry place in a dike. Avoid heat, flames, sparks and other sources of ignition. Keep container tightly closed and in a well ventilated place. Avoid direct sunlight. Subject to storage regulations: U.S. OSHA 29 CFR 1910.106. Grounding and bonding required. Keep separated from incompatible substances.

All other products

All other products are to be contained in over packs or sealed metal drums separately from other products. Do not mix soiled materials. These materials are also to be picked up by Environment Yukon special wastes pick up, which occurs annually or another organized special waste disposal program at Yukon Energy. Contact the Manager of Environment for further information.

15.0 PLAN ADMINISTRATION

The following table must be filled out when changes are made to the plan.
YEC shall review the spill contingency plan annually and provide a summary of that review, including any revisions to the plan, as a component of the annual report.

Document Release and Revision History

Revision #	Revised Section/Page #	Purpose of Release: Details of Revisions/Amendments	Approved By:	Effective Date
00		New document	Director, Operations	May 2000
01	New cover page #1, #2	New cover page #1, added revision history page #2, updated contact info as required	Director, Operations	March 2004
02	Page #7, #10, #11, #12	Updated contact info as required & updated fuel day tank amounts	Director, Operations	May 2007
03	Pages 5,7, 8, and 11	Updated contact info and reporting chain as required	Manager, Environment	December 2009
04	All	Added site specific spill response procedures, updates contact information, added list of contractors for external resources, added resources at risk, updated on site spill response resources inventory. Added spill classification and clean-up plan. Added Spill Plan acknowledgement form, added sample incident report form. Added CFO to YEC reporting chain	Environmental Coordinator	June 20, 2012
05	Site Specific pages	LNG and Oil and Gas regulation information added	Environmental Coordinator	February 24, 2014

Name:	Signature:	Review Date:
Director, Operations		
Leadhand Mechanical Maintenance		
Leadhand Hydro Maintenance		
Leadhand Electrical Maintenance		
EMS Manager		

Distribution List- Via YEC EMS SharePoint

This document is a Yukon Energy Environmental Management System (EMS) Environmental Work Plan (EWP), A hard copy of this document must be maintained in the operational area to which it refers (e.g., hydro plant) and replaced after the annual document review or whenever a revision is made to the plan.

References:

EMS-MP-011	Emergency Response
HS-000-E	MP-4 Incident Reporting & Investigation Procedures
HS-000-E-A	Incident Investigation Form
HS-000-E-B	Incident Reporting Form
EMS-MP-001	Environmental Management System Scope and Structural Overview

For additional copies of this plan please visit the YEC Sharepoint site
https://sp2010.yec.yk.ca/Departments/env/Spill%20Contingency%20Plans/Forms/AllItems.aspx

INDEX

1.0 EMERGENCY CONTACT INFORMATION 2
2.0 INITIAL ACTION/SAFE APPROACH GUIDELINES 3
3.0 PURPOSE AND SCOPE 4
4.0 NOTIFICATIONS 5
5.0 RESPONSE ORGANIZATION 6
6.0 SPILL SITE SAFETY PLAN 7
7.0 MATERIAL/EQUIPMENT 9
8.0 EQUIPMENT/SERVICES 19
9.0 CONTACT DIRECTORY 20
10.0 SITE SPECIFIC INFORMATION: WHITEHORSE 22
11.0 RESOURCES AT RISK 32
12.0 SITE SPECIFIC SCENARIOS 33
13.0 APPENDIX A: FORMS 35
Appendix A1: **ICS 201-BRIEFING DOCUMENT** 36
Appendix A2-: **ICS 214A – INDIVIDUAL LOG** 41
Appendix A3: **DIESEL FUEL -SAFETY MEASURES** 45
Appendix A4: **LIQUEFIED NATURAL GAS (LNG) – UN 1972 –SAFETY MEASURES** 47
Appendix A5: **NATURAL GAS- SAFETY MEASURES** 49
Appendix A6: **DELVAC 1340- SAFETY MEASURES** 51
Appendix A7: **COOLANT- CAT EC-1 (238-8650) - SAFETY MEASURES** 53
Appendix A8: **MOBILGARD 312 – SAFETY MEASURES** 55
Appendix A9: **TERESSO 46 – SAFETY MEASURES** 57
Appendix A10: **VARSOL – SAFETY MEASURES** 59
Appendix A11: **VOLTESSO 35 - SAFETY MEASURES** 61
Appendix A12: **SF6 GAS- SAFETY MEASURES** 63
Appendix A13: **WASTE OIL – SAFETY MEASURES** 65
Appendix A14: **BUTYL MERCAPTAN – SAFETY MEASURES** 67
14.0 WASTE MANAGEMENT 69
15.0 PLAN ADMINISTRATION 71

LIST OF TABLES

Table 1. Inventories/services supplied by contractor/consultant in the Whitehorse area 19
Table 2. Fuel, Petroleum Product and other Hazardous Materials Brought On-Site or Generated On-Site 28
Table 3. Site Description 32
Table 4. Other Possible Scenarios 34

LIST OF FIGURES

Figure 1. Contact/Reporting Flow Chart.....5
Figure 2. Total Volumes of Hazardous Materials at the Whitehorse Generating Station.....29
Figure 3. Sub-station S150 Oil.....30
Figure 4. Whitehorse Hydro #4 Oil.....31

Standard Audit Document

D = Document Review

O = Observational Tour

I = Audit Interviews

XXVI

XXVINSNY Revised: June 2010

Health and Safety Manual Verification

Does the company's health and safety program contain the following?	Yes	No
1. Company Health and Safety Policy *	☑	☐
2. Workplace Hazard Assessment and Control*	☑	☐
3. Safe Work Practices	☑	☐
4. Safe Job Procedures	☑	☐
5. Company Rules	☑	☐
6. Personal Protective Equipment (PPE) *	☑	☐
7. Preventative Maintenance *	☑	☐
8. Training and Communication *	☑	☐
9. Inspections *	☑	☐
10. Investigations and Incident Reporting *	☑	☐
11. Emergency Preparedness	☑	☐
12. Records and Statistics	☑	☐
13. Legislation Compliance	☑	☐
14. Joint Health and Safety Committee and Safety Representatives	☑	☐

Missing Sections:
If any of the above elements are missing from the health and safety manual, both parties (company and auditor) may want to consider postponing the audit at this stage until corrective action can be completed.

Policy Statements*:
Some of the above program sections may exist in another form within the health and safety manual. Some companies may combine all of the above policies into **one corporate policy statement**, which is an acceptable industry practice. The auditor must take this into consideration when reviewing the health and safety program.

Audit Information Sheet

Start Date of Audit: SEPT. 4, 2012. End Date of Audit (last day on site): September 21, 2012

Type of Audit: ☐ Self ☐ Internal ☒ External ☐ Auditor Maintenance Only

Company Data

Legal Name: YUKON ENERGY CORPORATION.

Address: #2 MILES CANYON RD. City: WHITEHORSE Territory: YT Postal Code: Y1A 6S7

Phone Number: (867) 393-5353 Fax Number: (867) 393-5322. E-mail: melanie.pettefer@yec.yk.ca

Key Contact: Melanie Pettefer Number of Workers at Peak Periods: 83

WCB Information

Acct #s	Industry Code(s)	Nature and Type of Work Done	Acct #s	Industry Code(s)	Nature and Type of Work Done
11038	313	. electrical utility . line transmission . distibution -		313	Power Generation

Auditor Data

Name: AMBER SHELTON Certification Number: 6154

Company: SHE CONSULTING INC Telephone Number: 867 335-6540

Address: 18 Nunatak Place Fax Number: n/a

City: Whitehorse Territory: YT Postal Code: Y1A 0E6 E-mail: SHE@northwestel.net

Pre-Audit Meeting

Agenda

1. Purpose and scope of audit ☑
2. Proposed audit schedule ☑
3. Confidentiality of information ☑
4. Code of Ethics ☑
5. Close-out meeting ☑
6. Any questions or concerns ☑

Company Name: YUKON ENERGY CORP.

Auditor Name: AMBER SHEWEN Date: SEPTEMBER 4/2012

Name of Key Contact: MELANIE PETTEFER

In Attendance: DAVID MORRISON

MELANIE PETTEFER

Anticipated Date of Audit: SEPT 4/2012

Anticipated date of audit close out meeting: Sept 21/2012

Notes:

Signatures:

Auditor

Company Representative

List of Active Work Sites

Site Location(s)	Visited	Number of Site Personnel		Number Interviewed	
		Managers/ Supervisors	Workers	Managers/ Supervisors	Workers
1. Whitehorse	✓	30	43	6	8
2. Mayo	✓	0	2	0	1
3. Dawson	✓	0	5	0	2
4. Aishihik	x	0	0	0	0
5. Fish Ladder	x	0	0	0	0
6. Faro	x	0	0	0	0
7.					
8.					
9.					
10.					
11.					
12.					
13.					
14.					
15.					
16.					
17.					
18.					
19.					

Total Sites Visited: 3 Total Personnel: 80 Total Interviewed: 17

Section #1: Company Health and Safety Policy

Health and Safety Program Verification	Score	Technique Employed			Points Awarded
		D	O	I	
1. Company Health and Safety Policy					
Does the employer have a written health and safety policy that:					
1.1 Is signed by the president, CEO, or local senior management?	3	✓			3
Comments:					
1.2 Includes management's commitment to provide a safe and healthy work environment?	3	✓			3
Comments:					
1.3 Recognizes the right of workers to work in a safe and healthy work environment?	2	✓			2
Comments:					
1.4 Is current and dated?	2	✓			2
Comments:					
1.5 Is reviewed annually by management?	2	X			0
Comments:					

Boxed numbers are required for SMALL EMPLOYERS. Large employers require all sections. Minimum standard is 50% of total possible points.

Health and Safety Program Verification	Score	Technique Employed			Points Awarded
1. Company Health and Safety Policy - continued		D	O	I	
1.6 Is prominently posted or made available to the worker?	3		✓ OR	✓	3
Comments:					
1.7 Addresses accountability and responsibility for health and safety for all workplace parties?	6	✓	AND	✓	6
Comments:					
1.8 Is understood by personnel?	3			✓	3
Comments:					
COR Total points possible/awarded	**24**				22
SECOR Total points possible/awarded	**22**				

Boxed numbers are required for SMALL EMPLOYERS. Large employers require all sections. Minimum standard is 50% of total possible points.

Section #2: Workplace Hazard Assessment and Control

Health & Safety Program Verification	Score	Technique Employed			Points Awarded
2. Workplace Hazard Assessment and Control		D	O	I	
2.1 Are written hazard assessments being performed on all worksites that identify jobsite health and safety hazards?	7	✓	AND	✓	7
Comments:					
2.2 Does the employer use an on-going hazard assessment process?	6	✓	AND	✓	6
Comments:					
2.3 Are appropriate personnel involved in the hazard assessment process?	5	✓	AND	✓	5
Comments:					
2.4 Are the hazards identified?	3	X			0
Comments:					
2.5 Are the hazards prioritized based on exposure?	1	X			0
Comments:					
2.6 Are the hazards prioritized based on consequence?	1	X			0
Comments:					

Boxed numbers are required for SMALL EMPLOYERS. Large employers require all sections. Minimum standard is 50% of total possible points.

Health & Safety Program Verification	Score	Technique Employed			Points Awarded
2. Workplace Hazard Assessment and Control – Cont'd		D	O	I	
2.7 Is there a list of identified critical tasks?	3	✓			3
Comments:					
2.8 Are controls developed for identified hazards?	3	✓			3
Comments:					
2.9 Are controls implemented in a timely manner?	3	✓ AND ✓			3
Comments:					
2.10 Are appropriate personnel involved/informed of the control strategies?	3	✓	AND	✓	3
Comments:					
2.11 Does the company have a process for evaluating/monitoring contractors?	4	✓			4
Comments:					
2.12 Does management support the ongoing application of the hazard assessment process?	3	X	AND	✓	0
Comments:					
COR Total points possible/awarded	**42**				34
SECOR Total points possible/awarded	**35**				

Boxed numbers are required for SMALL EMPLOYERS. Large employers require all sections. Minimum standard is 50% of total possible points.

Section #3: Safe Work Practices

Health & Safety Program Verification	Score	Technique Employed				Points Awarded
3. Safe Work Practices		D		O	I	
3.1 Do the safe work practices accurately reflect the company's activities?	2	✓				2
Comments:						
3.2 Have all applicable safe work practices been written?	5	✓	AND	✓		5
Comments:						
3.3 Are the practices easy for workers to understand?	2				✓	2
Comments:						
3.4 Are they readily available for worker reference?	2			✓ OR	✓	2
Comments:						
3.5 Are they followed by workers on a regular basis?	2			✓ OR	✓	2
Comments:						
3.6 Have both management/supervisors and workers participated in the development and/or review of safe work practices?	4	✓		OR	✓	4
Comments:						
COR total points possible/awarded	17					17
SECOR total points possible/awarded	13					

Boxed numbers are required for SMALL EMPLOYERS. Large employers require all sections. Minimum standard is 50% of total possible points.

Section #4: Safe Job Procedures

Health & Safety Program Verification	Score	Technique Employed			Points Awarded
		D	O	I	
4. Safe Job Procedures					
4.1 Do the safe job procedures accurately reflect the employer's activities?	2	✓	AND	✓	2
Comments:					
4.2 Have all critical safe job procedures been written?	5	✓ AND ✓			5
Comments:					
4.3 Are the procedures easy for workers to understand?	2			✓	2
Comments:					
4.4 Are safe job procedures followed by workers on a regular basis?	2		✓ AND ✓		2
Comments:					

Boxed numbers are required for SMALL EMPLOYERS. Large employers require all sections. Minimum standard is 50% of total possible points.

Health & Safety Program Verification	Score	Technique Employed			Points Awarded
4. Safe Job Procedures – Implementation		D	O	I	
4.5 Are these procedures available and easily accessible to workers?	2		✓ AND	✓	2
Comments:					
4.6 Have both management/supervisors and workers participated in the development/review of these procedures?	4	✓	OR	✓	4
Comments:					
COR total points possible/awarded	17				
SECOR total points possible/awarded	13				17

Boxed numbers are required for SMALL EMPLOYERS. Large employers require all sections. Minimum standard is 50% of total possible points.

Section #5: Company Rules

Health & Safety Program Verification	Score	Technique Employed				Points Awarded
		D	O		I	
5. Company Rules						
5.1 Are the rules clearly stated in writing?	2	✓				2
Comments:						
5.2 Are the rules prominently posted or provided to each worker?	1		✗	AND	✓	0
Comments:						
5.3 Do workers understand company and site specific rules?	2				✓	2
Comments:						
5.4 Does the program address non-conformance and progressive disciplinary actions?	2	✓				2
Comments:						
5.5 Are all rules applied/enforced consistently with all employees?	2	✓		AND	✓	2
Comments:						
COR and SECOR total points possible/awarded	9					8

Boxed numbers are required for SMALL EMPLOYERS. Large employers require all sections. Minimum standard is 50% of total possible points.

Section #6: Personal Protective Equipment (PPE)

Health & Safety Program Verification	Score	Technique Employed			Points Awarded
		D	O	I	
6. Personal Protective Equipment (PPE)					
6.1 Is there a written policy for PPE?	2	✓			2
Comments:					
6.2 Are workers made aware of the policy and legislation for PPE?	2	✓	AND	✓	2
Comments:					
6.3 Do all employees have access to basic PPE?	2		✓ OR	✓	2
Comments:					
6.4 Is specialized PPE available to workers when required?	3		✓ AND	✓	3
Comments:					

Boxed numbers are required for SMALL EMPLOYERS. Large employers require all sections. Minimum standard is 50% of total possible points.

Health & Safety Program Verification	Score	Technique Employed			Points Awarded
6. Personal Protective Equipment (PPE) - continued		D	O	I	
6.5 Is the correct PPE used by all employees when required?	2		✓		2
Comments:					
6.6 Are there written procedures for the proper fitting, care and use of specialized PPE?	2	X			0
Comments:					
6.7 Are employees given instruction or training in the use of PPE as required?	3	X	AND	✓	0
Comments:					
6.8 Is there criteria used to select PPE?	2	✓	AND	✓	2
Comments:					
6.9 Is there a process in place to regularly inspect and maintain basic/specialized PPE?	3	X			0
Comments:					
COR Total points possible/awarded	21				13
SECOR Total points possible/awarded	17				

Boxed numbers are required for SMALL EMPLOYERS. Large employers require all sections. Minimum standard is 50% of total possible points.

Section #7: Preventative Maintenance

Health & Safety Program Verification	Score	Technique Employed			Points Awarded
		D	O	I	
7. Preventative Maintenance Does the preventative maintenance program of facilities, tools, equipment and vehicles include:					
7.1 An inventory of items to be maintained?	2	✓			2
Comments:					
7.2 Maintenance meeting manufacturer and regulatory standards?	4	✓	AND	✓	4
Comments:					
7.3 Records of actions taken?	2	X			0
Comments:					

Boxed numbers are required for SMALL EMPLOYERS. Large employers require all sections. Minimum standard is 50% of total possible points.

Health & Safety Program Verification	Score	Technique Employed				Points Awarded
		D	O		I	
7. Preventative Maintenance Program - continued						
7.4 Is there a system to effectively remove defective tools, equipment or vehicles from service?	4	✓	AND		✓	4
Comments:						
7.5 Is this system followed?	2		X	OR	X	0
Comments:						
7.6 Does a qualified/competent person perform the inspection and maintenance?	2	✓	AND		✓	2
Comments:						
COR Total points possible/awarded	16					12
SECOR Total points possible/awarded	14					

Boxed numbers are required for SMALL EMPLOYERS. Large employers require all sections. Minimum standard is 50% of total possible points.

Section #8: Training and Communication

Health & Safety Program Verification	Score	Technique Employed			Points Awarded
8. Training and Communication		D	O	I	
8.1 Does the employer have a formal orientation program?	4	✓			4
Comments:					
8.2 Is orientation mandatory for all new employees before starting work?	4	X	AND	✓	0
Comments:					
8.3 Is there a standardized written orientation form?	2	✓			2
Comments:					
8.4 Does the form provide for signatures of both workers and the person conducting the orientation?	2	✓			2
Comments:					
8.5 Are training requirements verified or training provided before starting work?	2	✓	AND	✓	2
Comments:					

Boxed numbers are required for SMALL EMPLOYERS. Large employers require all sections. Minimum standard is 50% of total possible points.

Health & Safety Program Verification	Score	Technique Employed			Points Awarded
8. Training and Communication - continued		D	O	I	
8.6 Are training records maintained?	2	✓			2
Comments:					
8.7 Is job specific training provided and documented as required?	2	X	AND	✓	0
Comments:					
8.8 Does a competent person conduct job specific training?	2	✓			2
Comments:					
8.9 Have supervisors received training in workplace inspections and health and safety responsibilities?	6	✓	AND	✓	6
Comments:					
8.10 Is a system in place to measure applied knowledge that pertains to the company's health and safety orientation?	2	✓	AND	✓	2
Comments:					
8.11 Does the employer hold consistent health and safety meetings?	3	X	AND	✓	0
Comments:					

Boxed numbers are required.for SMALL EMPLOYERS. Large employers require all sections. Minimum standard is 50% of total possible points.

Health & Safety Program Verification	Score	Technique Employed			Points Awarded
8. Training and Communication - continued		D	O	I	
8.12 Does senior management attend/participate in health and safety meetings?	2	✓	AND	✓	2
Comments:					
8.13 Is a prepared topic or agenda followed and an attendance of the meetings kept?	3	✓			3
Comments:					
8.14 Does two-way communication exist during these meetings?	3	✓	AND	✓	3
Comments:					
8.15 Are tailgate/toolbox meetings held regularly and documented as per policy?	3	✓			3
Comments:					
COR Total points possible/awarded	42				33
SECOR Total points possible/awarded	36				

Boxed numbers are required for SMALL EMPLOYERS. Large employers require all sections. Minimum standard is 50% of total possible points.

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Section #9: Inspections

Health & Safety Program Verification	Score	Technique Employed			Points Awarded
9. Inspections		D	O	I	
9.1 Is there a written policy for inspections?	2	✓			2
Comments:					
9.2 Does the policy include frequency of inspections?	3	X			0
Comments:					
9.3 Is the required frequency being met?	4	X			0
Comments:					
9.4 Is there a form or checklist used for inspections?	3	✓			3
Comments:					
9.5 Are supervisors or trained personnel performing inspections as required by their policy?	3	✓	AND	✓	3
Comments:					

Boxed numbers are required for SMALL EMPLOYERS. Large employers require all sections. Minimum standard is 50% of total possible points.

Health & Safety Program Verification	Score	Technique Employed			Points Awarded
9. Inspections - continued		D	O	I	
9.6 Are workers involved in the inspection process?	3	✓	OR	X	3
Comments:					
9.7 Are all areas inspected as required?	3	X			0
Comments:					
9.8 Are identified deficiencies corrected in a timely manner?	3	✓	AND	✓	3
Comments:					
9.9 Does senior management participate/review the inspection process?	2	✓	AND	✓	2
Comments:					
9.10 Are inspection reports posted and/or communicated to appropriate employees?	4		✓ OR	✓	4
Comments:					
COR Total points possible/awarded	30				20
SECOR Total points possible/awarded	25				

Boxed numbers are required for SMALL EMPLOYERS. Large employers require all sections. Minimum standard is 50% of total possible points.

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Section #10: Investigations and Incident Reporting

Health & Safety Program Verification	Score	Technique Employed			Points Awarded
10. Investigations and Incident Reporting		D	O	I	
10.1 Is there a written investigation policy and reporting procedure?	2	✓			2
Comments:					
10.2 Is the policy being followed?	4	✓	AND	✓	4
Comments:					
10.3 Are standardized forms readily available and used?	2	✓			2
Comments:					
10.4 Do workers know the reporting process?	3			✓	3
Comments:					
10.5 Have supervisors been trained in investigation and reporting procedures?	3	✓	AND	✓	3
Comments:					

Boxed numbers are required for SMALL EMPLOYERS. Large employers require all sections. Minimum standard is 50% of total possible points.

Health & Safety Program Verification	Score	Technique Employed			Points Awarded
10. Investigations and Incident Reporting – Continued		D	O	I	
10.6 Are appropriate employees involved in investigations?	3	✓			3
Comments:					
10.7 Are near-miss (or no-loss) incidents being reported?	4	✓	AND	✓	4
Comments:					
10.8 Are recommendations for prevention/remedial action implemented in a timely manner?	4	✓	AND	✓	4
Comments:					
10.9 Are corrective actions communicated to workers?	3			✓	3
Comments:					
10.10 Are investigation reports reviewed by management?	2	✓			2
Comments:					
COR Total points possible/awarded	30				
SECOR Total points possible/awarded	25				30

Section #11: Emergency Preparedness

Health & Safety Program Verification	Score	Technique Employed			Points Awarded
11. Emergency Preparedness		D	O	I	
11.1 Are the emergency preparedness plans appropriate to work activities?	6	X	AND X		0
Comments:					
11.2 Does the plan include a requirement for training in emergency procedures, roles and responsibilities?	3	✓	AND	✓	3
Comments:					
11.3 Has the emergency response plan been tested for deficiencies and corrective action taken?	4	X	AND	X	0
Comments:					
11.4 Does the employer have a written fire response plan?	2	✓			2
Comments:					
11.5 Are the correct class and size of fire extinguishers available, marked and visible?	2		✓		2
Comments:					

Boxed numbers are required for SMALL EMPLOYERS. Large employers require all sections. Minimum standard is 50% of total possible points.

Health & Safety Program Verification	Score	Technique Employed			Points Awarded
11. Emergency Preparedness - continued		D	O	I	
11.6 Are extinguishers regularly inspected and maintained?	2	X	OR X		0
Comments:					
11.7 Is an appropriate emergency communication system available?	2		✓ AND ✓		2
Comments:					
11.8 Are there adequate first aid supplies and facilities?	2		✓		2
Comments:					
11.9 Are the required number of qualified first aid personnel on site?	3		✓ OR ✓		3
Comments:					
11.10 Is there a means to transport an injured employee to a medical facility?	1		✓ AND ✓		1
Comments:					
COR Total points possible/awarded SECOR Total points possible/awarded	27 25				15

Section #12: Records and Statistics

Health & Safety Program Verification	Score	Technique Employed			Points Awarded
12. Records and Statistics		D	O	I	
12.1 Is there a process to organize and manage program documentation?	2	✓			2
Comments:					
12.2 Are adequate health and safety activity summaries developed and maintained?	2	✓			2
Comments:					
12.3 Are health and safety statistical reports generated on an on-going/regular basis and readily available?	2	✓			2
Comments:					
12.4 Does the company compare health and safety performance year to year?	2	✓			2
Comments:					
12.5 Are the annual statistics analyzed and needs or trends identified?	2	✓			2
Comments:					

Boxed numbers are required for SMALL EMPLOYERS. Large employers require all sections. Minimum standard is 50% of total possible points.

Health & Safety Program Verification	Score	Technique Employed			Points Awarded
12. Statistics & Records - continued		D	O	I	
12.6 Are adequate first aid treatment records kept?	3	X			0
Comments:					
12.7 Was an action plan developed based on the most recent audit?	2	✓			2
Comments:					
12.8 Was that action plan communicated and implemented?	3	✓	OR	✓	3
Comments:					
COR Total points possible/awarded	18				15
SECOR Total points possible/awarded	12				

Boxed numbers are required for SMALL EMPLOYERS. Large employers require all sections. Minimum standard is 50% of total possible points.

Section #13: Legislation

Health & Safety Program Verification	Score	Technique Employed			Points Awarded
13. Legislation		D	O	I	
13.1 Is OHS legislation available for employees review?	2		✓ OR	✓	2
Comments:					
13.2 Does management/supervision reference relevant legislation during job planning?	3			✓	3
Comments:					
13.3 Are employees aware of their legislative rights (right to know, the right to participate and the right to refuse)?	3			✓	3
Comments:					
13.4 Are employees aware of their responsibilities?	2			✓	2
Comments:					
13.5 Does the employer's injury and incident reporting meet the legislated requirement?	2			✓	2
Comments:					
13.6 Does medical monitoring meet legislated standards?	1	✓			1
Comments:					
COR Total points possible/awarded	13				13
SECOR Total points possible/awarded	10				

Boxed numbers are required for SMALL EMPLOYERS. Large employers require all sections. Minimum standard is 50% of total possible points.

Section #14: JHSC & Safety Representatives

Health & Safety Program Verification	Score	Technique Employed			Points Awarded
14. JHSC, Safety Reps		D	O	I	
14.1 Does the health and safety committee or safety representative meet OHS Act requirements?	3	✓	OR	✓	3
Comments:					
14.2 Are committee members or safety representatives familiar with their legal duties and responsibilities?	2			✓	2
Comments:					
14.3 Have committee members or safety representatives received training in how to carry out their duties and responsibilities?	1	✓			1
Comments:					
14.4 Are committee minutes posted or made readily available for employees to read?	2		✓ OR	✓	2
Comments:					
14.5 Are management and workers represented on the safety committee?	1	✓	AND	✓	1
Comments:					

Boxed numbers are required for SMALL EMPLOYERS. Large employers require all sections. Minimum standard is 50% of total possible points.

Section #14: JHSC & Safety Representatives- *continued*

	Score	Technique Employed			Points Awarded
14. JHSC, Safety Reps		D	O	I	
14.6 Do committee members and/or safety representatives perform monthly inspections of the workplace?	1	X			0
Comments:					
14.7 Does the safety committee meet at least once per month?	1	✓			1
Comments:					
14.8 Do committee members and safety representatives review accident/incident reports?	1	✓	AND	✓	1
Comments:					
14.8.1 Does the safety committee and/or safety representatives make recommendations for workplace health & safety improvements?	1	✓	AND	✓	1
Comments:					
14.9 Are committee recommendations acted on by management? Or Are hazardous situations reported by the safety representative acted upon?	2	✓	AND	✓	2
Comments:					
COR Total points possible/awarded	15				14
SECOR Total points possible/awarded	10				

Boxed numbers are required for SMALL EMPLOYERS. Large employers require all sections. Minimum standard is 50% of total possible points.

Audit Summary Sheet

Company: Yukon Energy Corp Name of Auditor: Amber Shewen Date of Audit: Sept 21, 2012

Section #	Section Name	Possible Score	Actual Score	Minimum Standard	Section Percentage
1	Company Health and Safety Policy	24	22	14	92
2	Workplace Hazard Assessment and Control	42	34	22	81
3	Safe Work Practices	17	17	9	100
4	Safe Job Procedures	17	17	9	100
5	Company Rules	9	8	5	89
6	Personal Protective Equipment	21	13	11	62
7	Preventative Maintenance	16	12	8	75
8	Training and Communication	42	33 ao	21	79 (88) ao
9	Inspections	30	20	15	67
10	Investigations and Incident Reporting	30	30	15	100
11	Emergency Preparedness	27	15	14	83
12	Records and Statistics	18	15	9	83
13	Legislation Compliance	13	13	7	100
14	JHSC & Safety Rep	15	14	8	93
	TOTAL	**321**	267 ao		

Minimum Standard = 80% overall score and 50% each section

Reviewed: _____
Senior Manager or Company Designate

Actual Score 267 / Possible Score 321 x 100 = 82 ao %

_____
Auditor

Standard Achieved: **YES** ✓ **NO** _____

Goal for Next Audit: 90% Percentage

The goal for the next audit must be set by the senior manager or company designate.

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November 19, 2013

Letter of Good Standing

Company Name: Yukon Energy Corporation
Address: P.O. Box. 5920
Whitehorse YT
Y1A 6S7

Certificate No: 2009 - 103

Please be advised that the above named applicant is an active participant in the COR program and holds a valid Certificate of Recognition (COR) through the Northern Safety Network Yukon.

Issue date: September 24, 2013

Valid To: September 24, 2014

Sincerely,

Andria Hyndman
COR Coordinator

478 Range Road, Whitehorse, Yukon Y1A 3A2
tel 867.633.6673 fax 867.633.6391 email info@yukonsafety.com
yukonsafety.com

TOPIC: **Necessity**

REFERENCE: **Application, page 4**

Projected in-service for the third natural gas-fired unit (4.4 MW) will occur as required to meet grid capacity planning requirements, and is anticipated to be within a few years after the first two units are in-service.

PREAMBLE:

The Board requires further information.

QUESTION:

a) What is the current project in-service date for the third natural gas-fired unit (the additional 4.4 MW of generation capacity) with WD1 and WD2 remaining in place?

ANSWER:

(a)

The Project is being developed for late 2014 because WD1 and WD2 (with 8 MW of current de-rated capacity) are end-of-life units by 2015. After required retirement of these units, the forecast capacity shortfall in 2015 to meet the capacity planning criteria is 7.0 MW. The Project proposes that WD1 and WD2 be decommissioned when the two new gas-engines (8.8 MW) are commissioned, and accordingly WD1 and WD2 will not remain in place, i.e., will not be connected to the grid or able to provide reliable capacity.

Projected in service for the third natural gas-fired unit (4.4 MW) will occur as required to meet grid capacity planning requirements. Based on the updated Base Case load forecast provided in Appendix C of the Application, the currently projected in-service date for the third natural gas-fired unit (the additional 4.4 MW of generation capacity) is late 2016 in order to ensure that the capacity shortfall forecast for 2017 will be fully addressed. Please also see response to YUB-1-30(a), (b), and (c).

TOPIC: **Components on expanded site area**

REFERENCE: **Application, page 5 and page 6**

…including a separate switchgear module, a fluid transfer station, and a small substation to transmit power from the new generating units to the electrical grid via S150 substation.

The new small substation in the Expanded Site Area will have quick connect capability for a standby mobile genset in the event that this is required due to loss of connection to S150. Heat to start the vapourizer will be from the glycol/common water loop that will be kept warm year round (using multiple heat sources, e.g., diesel and gas units when operating, and an electric boiler, diesel and natural gas boiler in the diesel plant) to keep diesel and gas gensets on hot standby.

PREAMBLE:

The Board requires further information.

QUESTION:

a) Please provide details regarding the components and component costs of the LNG project substation.

b) Is the sizing of the small substation predicated on the installation of only the three LNG units or future installation?

c) Does the LNG substation design afford SCADA control and protection of the units?

d) With respect to the alternative diesel option — i.e. two 6.7 MW diesel units — are there any incremental substation costs?

e) Under which item in Table 3.1 are the costs for “quick connect capability for a standby mobile genset” shown?

f) Does YEC currently have a standby mobile genset in Whitehorse that can be put in place quickly if there is a loss of connection to S150? If not, are the purchase costs of a standby mobile genset included in Table 3.1?

g) After loss of connectivity with S150, how much time can elapse before the genset is necessary?

ANSWER:

(a)

Please see response to YCS/LE-YEC-1-11(c).

(b)

The size of the substation would remain the same whether two or three natural gas units are installed.

(c)

Substation design includes SCADA control and protection of the units.

(d)

From a major equipment and total capacity standpoint, no significant substation cost increase is foreseen whether the generation be from three GE Jenbacher engines or two Wartsila engines.

(e)

The “quick connect capability for a standby mobile genset” fall under the LNG Gen – Engines category as it is part of the scope of the engine module manufacturer.

(f)

Yukon Energy has several mobile generators stored within the Whitehorse Generation Facility complex that can be deployed on very short notice. Mobile generator YM2 rated

at 150kW will be the preferred mobile generator. It is on a trailer that can be hauled by any Yukon Energy service vehicle thus can be redeployed very quickly.

(g)

The Site Uninterruptible Power Supply (UPS) systems are designed for up to a 24-hour loss of station service power for the most critical systems such as the Flame and Gas detection system. Depending on the ambient temperatures at the time of the outage, station service power would be required to provide power to the systems within the facility to prevent freeze-up. The timeframe is not yet known as the detailed design is not yet completed to be able to estimate the residual heat in the various systems and the rate of cool-down. At the time the detailed design is completed a standby genset operating procedure will be developed to ensure the facility is not affected by loss of station service power for any extended period of time.

TOPIC: **Other site infrastructure**

REFERENCE: **Application, page 6**

There are, however, several feasible options for this component including the ditch/depression located just south of the existing main gate or to a site on the west side of Robert Service Way so as to tie into the existing drainage infrastructure maintained by the City of Whitehorse. The final location and design (by an engineer licensed to practice in the Yukon) of the storm water retention pond will be determined in collaboration with the City and applicable regulators as a part of the detailed design to ensure it will be able to handle run off from the Project site and from Robert Service Way.

PREAMBLE:

The Board requires further information.

QUESTION:

a) Please provide an update regarding how close YEC is to completing final location and design of the storm water retention pond.

b) Are the LNG truck offloading, storage, and vapourization facilities and related infrastructure sized for only the three proposed LNG units? Please explain how future expansion of the LNG facilities is to take place.

c) Were other locations considered with respect to the LNG truck offloading, storage, and vapourization facilities? If yes, please explain why these sites were not acceptable.

ANSWER:

(a)

YEC is close to finalizing, in collaboration with the City and applicable regulators, the location and design of the storm water retention pond on the Expanded Site Area.

(b)

No. The LNG truck offloading, storage and vapourization facilities and related infrastructure are not all sized for only the three proposed natural gas-fired generating units.

As reviewed in response to YUB-YEC-1-6, this site is designed to accommodate additional storage tank capacity beyond the three tanks (499.5 m^3 capacity) required for the three initial gas engines, and underground gas piping from the Expanded Site Area to the existing WTGS diesel plant is being included in 2014 that will enable future replacement of existing diesel generation units to future natural gas or dual fuel generation units, as well as conversion of existing diesel engines to blend fuel (diesel and natural gas) and conversion of the existing oil boiler to natural gas. The vapourization unit is designed to be able to provide gas requirements for up to 30 MW of gas engine capacity.

Subject to ongoing confirmation of ratepayer savings, future expansion of gas displacement of diesel fuel generation is expected to occur as required in response to grid capacity planning shortfalls resulting from load growth and/or diesel unit retirements. The following are noted in this regard:

- Opportunities for blended fuel use with existing diesel units will be examined in the near term, i.e., such opportunities involve minimal capital costs (compared to new units) and provide added opportunity to use the LNG infrastructure now being established to displace diesel fuel prior to retirement dates for existing diesel units.

- When a new engine is required to meet capacity planning requirements the opportunity will be examined to place new natural gas or dual fuel generation units in the bays previously used by WD1 and WD2. Again, new engines using gas provide added opportunity to use the LNG infrastructure now being established to displace diesel fuel prior to retirement dates for existing diesel units.

- The existing WTGS was initially commissioned in 1968, and its five existing diesel engines that will remain after WD1 and WD2 are retired are all planned to be retired within the next 13 years (see Page 22 and Appendix C of the

Application). This will create ongoing opportunities for future replacement of existing diesel generation units to future natural gas or dual fuel generation units.

(c)

Yes - other locations were considered with respect to the LNG truck offloading, storage, and vapourization facilities. As reviewed below, the existing WTGS operation was determined to be an optimum location for the Project and, based on that decision, options were reviewed regarding locations with respect to the LNG truck offloading, storage, and vapourization facilities needed for gas-fired generation at a modernized WTGS.

At the outset, the existing WTGS operation was determined to be an optimum location for the Project. Specifically, Whitehorse is the nearest practical grid location for LNG deliveries from Alberta or British Columbia. It is the location of the Yukon grid's largest load centre, and it offers the opportunity to use new gas fired generation to modernize the Whitehorse plant facilities, with its established infrastructure (including transformer capability and on site staffing needed to operate and maintain the remaining diesel plant), concurrent with the retirement of existing diesel capacity at these facilities. Further, major elements of the existing diesel plant at the WTGS will continue to be required over at least the next decade under any scenario examined.

New "greenfield" site options in the Whitehorse area and separate and a greater distance from the WTGS (such as near the Takhini substation) were considered, but were not found to be cost effective or practical for the following reasons (please see also YCS- LE-YEC-1-40(a) for further detail regarding the Takhini substation [or Mayo Road] location):

- Such options would forego the substantive opportunity for efficiencies and cost savings associated with the existing site (including shorter response times for operational tasks and in the event of a system failure);

- Such options would preclude current and future use of waste heat (produced during thermal electricity production) to meet existing or new thermal loads at the WTGS.

- Such options would require upgrading of communication equipment over a longer distance to allow for remote control and closed circuit television requirements.

- Such a development would preclude potential future conversion of existing WTGS diesel engines (four EMD units and one caterpillar unit) to bi-fuel (diesel and natural gas), which could prove beneficial in reducing operating costs of remaining diesel engines.

- Such a development would preclude potential opportunity to support the City of Whitehorse, Kwanlin Dün First Nation, or others with any gas and/or waste heat that they may look to use in developing their respective lands adjacent to the proposed site in the future.

Focusing on the WTGS site, initial investigations confirmed that it would not be feasible or cost effective to locate the LNG unload, storage and vapourization facilities (the "LNG Facilities") on the existing property, given objectives to facilitate conversion of diesel to gas at this facility over a series of phases linked to decommissioning of existing diesel units.

As noted in the YESAB Project Proposal (Chapter 6, Section 6.2.2 – Alternative Means of Carrying out the Project), following a determination that a new site, outside the existing Yukon Energy property, would be required for the LNG Facilities, nearby site options were examined on each side of Robert Service Way.

- **Site Options across Robert Service Way:** Four sites were identified across Robert Service Way from the WTGS that could accommodate the assumed LNG Facilities requirements (based on review of site areas, and any potential interference with the Whitehorse Airport) – including two sites closest to Yukon Energy's site and adjacent to the west side of Robert Service Way (the Ta'an Kwäch'än Council [TKC]) site and the City of Whitehorse site). The two other sites examined (owned by Kwanlin Dün First Nation (KDFN)), were not preferred due to greater distance from the WTGS site as well as closer proximity to the Alaska Highway and the flight paths for the Whitehorse Airport.

  Conceptual design and environmental data collection work assumed a preferred site on the TKC site (municipal engineering work determined that this site would be approximately $0.6 million lower cost than the alternative preferred City of

Whitehorse site). Ongoing consultations and review indicated that both the preferred and alternative preferred sites would need to be rezoned and for that purpose would be required as well to go through the City of Whitehorse Zoning Amendment (Official Community Plan or OCP) process.

- **Expanded Site Area Option on Yukon Energy-Side of Robert Service Way:** A new potential site option of approximately 1.5 ha was identified in March 2013 on the Yukon Energy-side of Robert Service Way and adjacent to the south end of the WTGS site (the Expanded Site Area). This site is owned primarily by the Yukon Government with adjacent White Pass & Yukon Railway right-of-way lands. It is already zoned for Public Utility use (and therefore its use for the LNG Facilities does not need to proceed through an OCP process).

  Yukon Energy confirmed the Yukon Government's willingness, in principle, to sell to Yukon Energy the portion of the Expanded Site Area owned by the Yukon Government (approximately 0.9 ha), and entered into discussions with White Pass and Yukon Railway to lease its lands within the Expanded Site Area (approximately 0.6 ha). Yukon Energy confirmed a preliminary site design that could accommodate on the Expanded Site Area both the LNG Facilities and GE J624 gas-fired engine modules, and that the Expanded Site Area option would allow for some capital cost savings (approximately $0.6 million) over the other preferred site options due to moving LNG storage closer to the WTGS site and the existing generating and substation facilities.

In October 2013 YEC learned that the White Pass and Yukon Railway property would not be leased to YEC for the Project, and a revised site plan was developed to accommodate the LNG Facilities and three GE J624 gas-fired engines on the portion of the Expanded Site Area owned by the Yukon Government (approximately 0.9 ha), with road access and utilities easements as required on the White Pass and Yukon Railway portion of the Expanded Site Area.

TOPIC: **Final design**

REFERENCE: **Application, page 7**

Additional changes to site layout and related components may occur during final design of the Project, subject in each instance to the restrictions that they be confined to the YEC-acquired property area within the Expanded Site Area and the vapour barrier requirements to comply and conform with the requirements of CSA Standard Z276-11: Liquefied Natural Gas (LNG) Production, Storage and Handling, as assessed in the vapour dispersion analysis.

PREAMBLE:

QUESTION:

a) When is final design of the project, per the above quote, expected to be completed?

b) Has YEC included contingency costs for design changes that may arise with respect to site layout and related components that may arise during final design of the LNG project?

c) If final design of the project is complete per part (a), please provide additional changes and related costs, if any, to site layout and related components shown in Appendix A.

ANSWER:

(a) and **(c)**

Final design of the Project is not yet complete.

The majority of the final design will be completed in the next three months (March to May 2014) in order to issue and award the civil, structural, mechanical, electrical and instrumentation construction contract. Minor design changes are expected to occur

during the course of construction as a result of new information from suppliers and on-site design modifications.

(b)

Yukon Energy has included $1.450 Million contingency in the updated Project capital cost estimate to cover construction contract ($1.000 Million), Project management/engineering ($0.20 Million) and Owners costs ($0.250 Million). Please see response to YUB-YEC-1-1(d).

TOPIC: **Project savings**

REFERENCE: **Application, page 7**

This schedule is driven by forecast thermal generation requirements for the winter of 2014/15, both to provide new thermal generation capacity for reliable service during that winter and to save in excess of $2.1 million of thermal fuel generation costs charged to ratepayers in 2015. Cost savings resulting from the Project will benefit all of Yukon's electricity ratepayers.

PREAMBLE:

QUESTION:

a) Please provide the GW.h of capacity required of WD1 and WD2 for the periods January 1, 2011 to June 30, 2011, January 1, 2012 to June 30, 2012, January 1, 2013 to June 30, 2013 and January 1, 2014 to June 30, 2014.

b) The $2.1-million savings reflects the "difference between estimated diesel fuel cost of $4.02 million with existing diesel units (based on YEC's 2012/13 GRA compliance filing average diesel fuel generation cost of 28.7 ¢/kW.h.), and $ 1.89 million with new LNG units (based on LNG fuel cost at 13.5 ¢/kW.h with 100% diesel displacement, and assuming A-train LNG transportation is established and an AECO gas price of $4.5 per MMBtu."
   i. Please provide the current average diesel fuel generation cost in ¢/kW.h.
   ii. Please provide the amount of diesel displacement (GW.h).
   iii. Please provide the current AECO gas price ($/Gj).
   iv. Please provide the calculation respecting how YEC obtained the $/MMBtu value to enable comparison of dollars saved in moving from diesel (¢/kW.h) to LNG ($/MMBtu).

c) Please explain what the $4.4 million estimate for the third unit includes.

d) Are there any updates to the estimated cost for the third unit at this time?

ANSWER:

(a)

Capacity requirements for each of the time periods referenced reflect MW required during the peak non-industrial winter load period for the grid (which can be expected to include Q1 of any year), taking into account firm hydro generation capacity and N-1 event conditions (i.e., loss of 37 MW at Aishihik due to loss of the transmission to Whitehorse). In this context, the relevance of 8.0 MW of de-rated WD1 and WD2 diesel capacity can be assessed in the context of all YEC diesel capacity (approximately 37 MW, including WD1 and WD2).

Appendix C of the Application (Table C-4) indicates N-1 surplus or shortfall for 2013 and 2014 (as well as subsequent years to 2030). Table 4-2 in the Application provides more detailed review of the assessment process for 2015 and beyond. A small surplus of 4.6 MW is indicated for 2013, and a shortfall of 0.8 MW is indicated for 2014 (after 3.50 MW for WD1 de-rated capacity is assumed to be retired). Based on actual peak loads and available capacity in each year, a surplus of 1.5 MW (reflects higher than normal peak) is estimated for 2012 and as surplus of 2.9 MW is estimated for 2011 (note that Mayo B not then in service, reducing capacity by 5.6 MW compared to 2012 and 2013).

As regards actual operation of required diesel capacity (including WD1 and WD2), this has been reduced in recent years by abundant water supplies and increased at certain times by capital works at Aishihik and Mayo (which required shut down of certain hydro facilities or other special events). Please see YECL-YEC-1-7(c) regarding actual operating hours and generation for WD1 and WD2 in each year 2010-2013.

(b)

The estimate at page 7 of the Application of fuel cost savings in excess of $2.1 million of thermal fuel generation costs charged to ratepayers in 2015 was based on the following:

- Forecast thermal generation of more than 14 GW.h for Base Case forecast (no Alexco) over six month period from January 1, 2015 to June 30, 2015. As stated in footnote 7 at page 7, this forecast is based on long-term average thermal generation (i.e., long-term average hydro generation is assumed, not actual hydro generation), as approved by the YUB to set rates charged to ratepayers as

a result of the 2012/2013 YEC GRA. Total long-term average thermal generation for 2015 under this Base Case scenario is forecast at 17.0 GW.h, and it is assumed that at least 14 GW.h would, on average, relate to the first six months of this year.

- The 14 GW.h supplied by existing diesel generation is assumed to cost $4.02 million, based on 28.7 c/kW.h (the approved 2012/13 GRA fuel price forecast, which YEC must in fact use for diesel generation expenses incurred).

- It is further assumed that 8.8 MW of new gas engine capacity would be able to displace 100% of this long term average diesel generation (this is consistent with later analysis in Table 4-3) at an assumed LNG fuel cost of $1.89 million, based on an assumed delivered cost of LNG of 13.5c/kW.h (as set out in the Application, this cost assumes A-Train LNG transportation, an AECO average gas price of $4.5/MMBtu, and 40% minimum energy conversion efficiency for the gas engines).

The following additional information is provided:

1. Current average diesel fuel generation cost for YEC, as approved in the 2012/13 GRA, is 28.7 c/kW.h; current fuel purchase costs are considerably higher than those approved in the last GRA, e.g., fuel purchase costs at Whitehorse are currently $1.1933 per litre [see YUB-YEC-1-42(c)] as compared with $1.0513/litre approved in the last GRA. The added cost reflected by the difference between GRA approved forecast fuel costs and actual fuel costs is charged to YEC's Rider F account and ultimately recovered from ratepayers.

2. As noted above, the amount of diesel displaced in the analysis is assumed at 14 GW.h and is based on long term average hydro generation. Actual diesel requirements are likely to be much lower in these months due to water conditions at this time being well above long-term averages.

3. Recent AECO prices are provided in YCS/LE-1-45 (a) and (b) by month through 2001 and early 2014. During 2013 the monthly AECO index price ranged from approximately $2.6/GJ (August) to $3.5/GJ (December). In January 2014 the average price was $3.8/GJ, and in February (through about mid-month) it has risen to approximately $5.5/GJ.

4. The delivered LNG fuel cost estimate of 13.5 cents/kW.h reflected the following calculations and assumptions beyond those noted above (see YCS/LE-1-14(d)):
    - Delivered cost of 13.5 cents/kW.h ($15.8/MMBtu)
    - Natural gas cost assumed at $4.5/MMbtu (3.8 cents per kW.h)
    - LNG haul from Calgary at 4.4 cents/kWh with A-Train ($5.2/MMBtu)
    - Assumed liquefaction costs at $6.2/MMBtu (5.3 cents/kW.h).

(c)

Yukon Energy does not at this time have firm pricing for the third GE natural gas-fired generating unit - the $4.4 million estimate is the best available information. It is intended to include the costs to acquire and install the unit, assuming that the construction completed in 2014 has provided all required civil facilities, switchgear, fluid transfer station facilities, LNG facilities, and substation requirements.

(d)

There are no updates to the estimated cost of the third unit at this time.

TOPIC: **Project alternatives**

REFERENCE: **Application, page 24 and page 25**

Two diesel generation alternatives to the Project during the 2014-2017 period have been considered: (a) life extension of the Mirrlees units (WD1 and WD2) and (b) replacement of the Mirrlees units with new higher-efficiency diesel engines.

a. YECL proposed, in its recent GRA, a 2 MW new diesel engine on the grid at Carcross at a cost of $3 million.
    i. Refurbishment of the remaining two Mirrlees units at WTGS (WD1 and WD2) is not considered to be practical or cost effective due to increasing lack of parts for these 45 year old engines.
    ii. The Corporation will be able to utilize some of the parts off of the retiring WD1 and WD2 engines...
    iii. If parts were not an issue, updated cost assessment for balance of plant work requirements for the WTGS suggest that extending the 9 MW rated capacity of these two units for another 10 years would likely require a capital cost of at least $6.75 million with risks that actual capital costs would exceed this amount.

b. Even if feasible and cost effective, the life extension option for WD1 and WD2 would at most only provide 9 MW of the forecast new capacity requirement and would do this at most for only 10 years, i.e., additional new capacity would be required by late 2016, with at least 4 MW of added capacity needed by late 2017 (to meet capacity requirements in early 2018) and the full 9 MW of new capacity would once again be needed by at least late 2024. The location and costs for this added 4 MW and subsequent 9 MW of capacity would need to be addressed.

    Assumed capital cost of at least $0.75 million per MW or 50% of the minimum $1.5 million per MW likely for a new unit in an existing facility without extensive balance of plant cost requirements such as are expected to be required at WTGS today. Based on experience, costs today for WD1 and WD2 are expected to materially exceed Yukon Energy's 2008/2009 GRA filing estimates of an expected average cost per MW for Mirrlees unit life extension at Whitehorse of

approximately $0.482 million/ MW including provision for common upgrade costs required.

PREAMBLE:

QUESTION:

a) Please provide the business cases and analyses undertaken regarding the life extension of units WD1 and WD2 relative to replacing the units with new diesel units and to the proposed LNG project.

b) If maintenance is an issue with units WD1 and WD2, please provide the maintenance history of these units for the years 2005 to 2013 inclusive. Please provide a table of capital expenditures for each of WD1 and WD2 for the years 2005 to 2013 inclusive.

c) YEC submits that the "…updated cost assessment for balance of plant work requirements for the WTGS suggest … $6.75 million."2 Please provide a table, similar to Table 3-1 which provides a summary of the cost items, and explanations regarding the cost items which make up the "balance of work requirements" for the WTGS.

d) Considering that WD1 andWD2 are scheduled to be decommissioned by 2015, is the WTGS "balance of plant work" required?

e) If available, please provide an assessment report for the WTGS facility.

f) Please contrast this conclusion with the recommendation made in the 2006 YEC 20-Year Resource Plan and explain any differences between the conclusion and the recommendation.

g) Please explain this change in comparison to the requested deferred overhaul expenditures of $0.18 million to the end of 2011, $1.28 million for 2012 and $1.60 million for 2013 in YEC's 2012-2013 GRA.

h) Please explain YEC's change in position regarding the refurbishment of the Whitehorse Mirrlees units as cited in paragraph 210 (page 42) of Appendix A to Board Order 2009-8.

i) Please provide further justification of the change in estimates for the refurbishment of the Whitehorse Mirrlees units from a cost of $0.482 million/MW in YEC's 2008-09 GRA to costs of at least $0.75/MW in this Application.

j) Why did YEC not undertake the refurbishments of WD1 and WD2 at an earlier date? Please explain.

k) As part of the WD3 refurbishment, did YEC upgrade the facilities for the WD units?

l) Please explain the WD3 refurbishment. How long was the life of WD3 expected to be extended? What was the total cost of the WD3 refurbishment?

m) If refurbishment of the WD1 and WD2 units extended the life for those units an additional 10 years, would this option allow sufficient time for alternative projects to proceed?

ANSWER:

(a)

Section 4.2.3 of the Application reviews the business case assumptions and core analysis undertaken regarding the life extensions of units WD1 and WD2 relative to replacing the units with new diesel units, establishing that new diesel units are preferred (less costly and more reliable) than life extension of units WD1 and WD2. The analysis then proceeds in Section 4.2.4 to provide an in depth cost impact assessment of new diesel relative to the Project with new natural gas units (net ratepayer cost savings by year for the Project relative to new diesel are presented in Table 4-3 for 2015 to 2018).

With regard to life extension of units WD1 and WD2 relative to replacing the units with new diesel, the business case analysis noted in the Application in summary includes the following:

- Life extension (refurbishment) of units WD1 and WD2 is not considered to be practical or cost effective due to increasing lack of parts for these 46 year old engines and a range of other factors, including:
    - If parts were not an issue, updated cost assessment for balance of plant work requirements for the WTGS suggest that extending the 9 MW rated capacity of these two units would likely require a capital cost of at least $6.75 million (i.e., at least $0.75 million per MW) with risks that actual capital costs would exceed this amount.
    - Life extension costs of $6.75 million for units WD1 and WD2 would at most provide only 9 MW of the forecast new capacity requirement and would do this at most for only a 10 year life. As a result, additional new capacity would be required by 2016, with at least 4 MW of added capacity needed by late 2017 (to meet capacity requirements in early 2018) and the full 9 MW of new capacity would once again be needed by at least late 2024.
    - Expected grid diesel generation requirements (based on long-term average hydro) would be supplied during this period if WD1 and WD2 are refurbished by relying on other existing diesel units (i.e., WD1 and WD2 use would likely be avoided, other than for emergency) at an approved average fuel cost of 28.7 cents/kW.h, e.g., $4.9 million fuel cost for forecast 2015 Base Case grid load default diesel requirement of 17 GW.h.

- The new diesel option used for comparison assumed that two new 6.7 MW diesel engines (13.4 MW) with higher fuel efficiency (40%) are installed in the WD1 and WD2 service bays, with the first unit installed in late 2014 at an estimated capital cost of $22.5 million and the second unit in late 2015 at a capital cost of $11.0 million, thereby providing benefits compared to the life extension of units WD1 and WD2, including:
    - Ability to meet grid capacity shortfall requirements through 2018 for reliable grid electricity supply under Base Case forecasts, without the need for added costs or selection of a location for other new capacity needed by 2016 under the WD1 and WD2 life extension option.

- Ability to use more efficient diesel generation units to meet a substantive share of ongoing forecast grid default diesel generation requirements (assumes long term average hydro generation), e.g., 90% displacement of old diesel generation in 2015 with one unit and 100% displacement of old diesel generation in 2016 with the second unit.
- The fuel cost saving is estimated at 4.1 cents/kW.h of old diesel displaced by the new diesel generation [new diesel cost at 24.6 cents per kW.h as explained in the Application versus old diesel average cost at 28.7 cents per kW.h, both assuming diesel fuel prices as approved in the last GRA].
- Overall, annual fuel cost savings for new diesel compared to life extension of units WD1 and WD2 are estimated as follows:
  - 2015 at $0.63 million saving [90% of 17 GW.h is displaced]
  - 2016 at $0.94 million saving [100% of 22.9 GW.h is displaced]
- However, comparison of annual capital costs for new diesel relative to life extension of units WD1 and WD2 is not so straight forward as comparison of fuel cost impacts, and requires consideration of the added capital costs needed to secure equivalent new capacity on the grid, i.e., the new diesel option provides 13.4 MW for a 40 year life while life extension of units WD1 and WD2 only provides 9 MW for 10 year life.
  - Annual capital costs for 13.4 MW of new diesel are shown in Table 4-3 at $2.04 million for 2015 and $2.59 million for 2016; focusing on 2016 when the full 13.4 MW is in service, these costs equal $0.193/MW, or $1.74 million for a 9 MW equivalent.
  - Using the same assumptions as in Table 4-3, annual capital costs for 9 MW life extension of units WD1 and WD2 (with 10 year depreciation) would equal $1.02 million for 2015 and $0.988 million for 2016.
  - Based on the above analysis, the added capital cost for a 9 MW equivalent new diesel option in 2016 is $0.75 million compared to life extension of units WD1 and WD2, and is more than offset by the $0.94 million fuel cost saving provided by the new diesel option.
  - The above assessment understates the cost savings with new diesel that would be expected by a full present value assessment of all expected costs through to 2030 with the new diesel option compared to life extension of units WD1 and WD2, i.e., such a present value assessment would include future capital costs to

secure added capacity requirement under each option as well as the present value of the fuel cost savings that are forecast to increase each year over the period.

- In summary, aside from the conclusion that life extension (refurbishment) of units WD1 and WD2 is not considered to be practical due to increasing lack of parts for these 45 year old engines and a range of other factors, the new diesel option is clearly more cost effective for ratepayers.

An updated business case for LNG versus new diesel versus life extension of WD1 and WD2 is detailed in Table 1 below using only first and second year costs to ratepayers, plus updated capital cost estimates for the Project (see YUB-YEC-1-1(d)[1]), and updated diesel and LNG fuel costs[2]. This business case analysis shows a positive benefit to ratepayers beginning in year 1 for LNG compared to new diesel and compared to refurbishment of WD1 and WD2. This analysis adjusts annual capital costs to a common 8.8 MW capacity level (2015 capacity provided by the Project) and ignores the capital cost related penalties for the life extension option for which new capacity is needed by the end of 2016 and (for the life extension option only) after 10 years when it is necessary to replace the refurbished diesels with new units at that time compared to deferring this capital for 40 years with the LNG or new diesel options. As noted in the earlier analysis, assessment limited to the first two years understates the cost savings with new diesel that would be expected by a full present value assessment of all expected costs through to 2030 with the new diesel option compared to life extension of units WD1 and WD2, i.e., such a present value assessment would include future capital costs to secure added capacity requirement under each option as well as the present value of the fuel cost savings that are forecast to increase each year over the period.

To complete the updated business case analysis, Table 2A below provides an updated Table 4-3 comparison of LNG and two stage new diesel development (first engine in late 2014 and second engine late 2015) for each year from 2014 to 2018 with the same updated capital cost estimates and updated fuel costs as considered in Table 1[3].

[1] Capital costs in 2014 for the new diesel are also reduced from $22.5 to $21.6 million to reflect planning cost estimate adjustments as described in YECL-YEC-1-6(b) and YUB-YEC-1-14(c).

[2] Diesel fuel costs are updated to reflect average diesel price to YEC at Whitehorse for the last six months as provided in YUB-YEC-1-42(c). LNG costs are updated for higher haul costs (YUB-YEC-1-44); the gas price of $4.50/MMBtu is retained as a conservative assumption based on AECO prices in the past six months which averages $3.7/MMBtu (YCS/LE-1-45 (a)).

[3] To be conservative, the Updated Table 4-3 also adds $1 million to the assumed capital cost for installing the third gas-fired engine in late 2016.

Compared with the Application, the updated Table 4-3 shows slightly lower net ratepayer cost savings for LNG relative to new diesel until 2018 (when net ratepayer cost savings for LNG relative to new diesel are slightly higher after the update).

Table 2B below provides an updated Table 4-3 comparison of LNG (the Project) with a one stage new diesel development (i.e., both engines installed in late 2014) for each year from 2014 to 2018 with the same updated capital cost estimates and updated fuel costs as considered in Table 1. As reviewed in response to YUB-YEC-1-14(d), this assessment more realistically defines the diesel option than the assumptions in Table 2A, in that a one stage development is the most likely approach for development of the new diesel option (and the overall cost for a two stage approach in Table 2A likely is understated with regard to the assumed $11.1 million cost for the second stage). Table 2B shows that ratepayer savings from the Project would be increased in 2015 by approximately $0.5 million if the new diesel option was done in one stage rather than in two stages.

Attachment 1 provides an electronic version of Table 1, Table 2A and Table 2B with formula intact.

Table 1 Updated Business Case - First and Second Year Ratepayer Cost for 8.8 MW of LNG versus New Diesel versus Life Extension Diesels (1st and 2nd Year Impacts)
(Costs standardized for 8.8 MW assumed capacity for each option)

	LNG	New Diesel	Refurb Diesel
Annual Depreciation	$898,675	$685,504	$660,000
Annual Return	$1,964,761	$1,527,493	$341,715
Annual Fuel Expense	$2,397,000	$4,464,200	$5,227,997
2015 Annual costs	**$5,260,436**	**$6,677,197**	**$6,229,712**
2016 Annual fuel costs	$3,419,576	$6,064,984	$6,690,299
2016 Annual costs	**$6,283,012**	**$8,277,981**	**$7,692,014**

Notes:
LNG cap costs assumed to be $36.5M for 8.8 MW
New diesel cap costs assumed to be $21.6M for 6.7 MW
Refurbished diesel cap cost assumed to be $6.75M for 9 MW
Salvage costs for LNG assumed to be $0.553 million
Salvage costs for new diesel assumed to be $0.950 million
Annual depreciation and return costs are for 2015
Annual generation 2015 & 2016 (LTA default diesel - Base Case)
2016 return costs were assumed to be the same as 2015
Diesel fuel price (Whitehorse) assumed to be $1.1265 per litre
LNG price (Whitehorse) assumed to be $4.5 per MMBTU

New diesel capital cost adj to 8.8 MW	$28,370,149	
Refurb diesel capital cost adj to 8.8 MW	$6,600,000	
LNG 8.8 MW cost	$36,500,000	
Amortization period for LNG & New Diesel	40	years
Amortization period for Refurbished Diesel	10	years
Annual Return on rate base	5.45%	
2015 Annual Generation in GWh	17	
2016 Annual Generation in GWh	22.9	
Displacement of old diesel: 2015	100%	
Displacement of old diesel: 2016	95%	
LNG fuel costs per kWh	14.1	
New diesel fuel costs per kWh (Whitehorse)	26.3	
Refurb diesel costs per kWh (grid average)	30.8	

Table 2-A: Table 4-3 Updated:
Ratepayer Impacts: Whitehorse Diesel-Natural Gas Conversion Project ($million)
(Project Compared to Two Stage New Diesel Alternative)

		2014	2015	2016	2017	2018
Capital cost ($million) at yr end						
Total	Diesel (new)	21.60	11.10			
	LNG	36.50		5.50		
Net	Diesel (new)	21.60	32.2	31.4	30.6	29.8
	LNG	36.5	35.6	40.2	39.2	38.1
Annual Capital Cost ($million)						
Deprec	Diesel (new)		0.516	0.794	0.794	0.794
	LNG		0.899	0.899	1.036	1.036
Return	Diesel (new)		1.466	1.732	1.689	1.646
	LNG		1.965	2.066	2.163	2.106
Total	Diesel (new)		1.982	2.526	2.483	2.440
	LNG		2.863	2.964	3.199	3.143
Difference (LNG-Diesel)			**0.882**	**0.438**	**0.716**	**0.703**
Annual Fuel Cost ($million)						
Forecast Diesel (GWh)			17	22.9	26.9	31.4
% New	Diesel (new)		90%	100%	100%	100%
	LNG		100%	95%	100%	100%
Fuel Cost	Diesel (new)		4.541	6.014	7.064	8.246
	LNG		2.397	3.420	3.793	4.427
Difference (LNG-Diesel)			**-2.144**	**-2.594**	**-3.271**	**-3.818**
Net Ratepayer Impact ($million)						
	Diesel (new)		6.522	8.540	9.547	10.685
	LNG		5.260	6.384	6.992	7.570
Difference (LNG-Diesel)			**-1.262**	**-2.156**	**-2.555**	**-3.115**

Notes:

1. All capital costs depreciated over 40 years; return on mid-year rate base at 5.45%/year.
2. Diesel fuel costs at 26.3 c/kWh new diesel (Whitehorse), 30.8 c/kWh other diesel (grid average).
3. LNG delivered fuel costs at 14.1 c/kWh (assumes supply from Shell Canada at Calgary at an AECO gas price of $4.50 per MMBtu and using A-Train units for delivery to Whitehorse with updated haul cost of $5.84/MMBtu [$5.31/MMBtu plus 10% for low initial volume]).

Table 2B: Table 4-3 Updated:
Ratepayer Impacts: Whitehorse Diesel-Natural Gas Conversion Project ($million)
(Project Compared to One Stage New Diesel Alternative)

		2014	2015	2016	2017	2018
Capital cost ($million) at yr end						
Total	Diesel (new)	32.70				
	LNG	36.50		5.50		
Net	Diesel (new)	32.70	31.9	31.1	30.3	29.5
	LNG	36.5	35.6	40.2	39.2	38.1
Annual Capital Cost ($million)						
Deprec	Diesel (new)		0.794	0.794	0.794	0.794
	LNG		0.899	0.899	1.036	1.036
Return	Diesel (new)		1.761	1.717	1.674	1.631
	LNG		1.965	2.066	2.163	2.106
Total	Diesel (new)		2.554	2.511	2.468	2.424
	LNG		2.863	2.964	3.199	3.143
Difference (LNG-Diesel)			**0.309**	**0.453**	**0.731**	**0.718**
Annual Fuel Cost ($million)						
Forecast Diesel (GWh)			17	22.9	26.9	31.4
% New	Diesel (new)		100%	100%	100%	100%
	LNG		100%	95%	100%	100%
Fuel Cost	Diesel (new)		4.464	6.014	7.064	8.246
	LNG		2.397	3.420	3.793	4.427
Difference (LNG-Diesel)			**-2.067**	**-2.594**	**-3.271**	**-3.818**
Net Ratepayer Impact ($million)						
	Diesel (new)		7.018	8.525	9.532	10.670
	LNG		5.260	6.384	6.992	7.570
Difference (LNG-Diesel)			**-1.758**	**-2.141**	**-2.540**	**-3.100**

Notes:

1. All capital costs depreciated over 40 years; return on mid-year rate base at 5.45%/year.
2. Diesel fuel costs at 26.3 c/kWh new diesel (Whitehorse), 30.8 c/kWh other diesel (grid average).
3. LNG delivered fuel costs at 14.1 c/kWh (assumes supply from Shell Canada at Calgary at an AECO gas price of $4.50 per MMBtu and using A-Train units for delivery to Whitehorse with updated haul cost of $5.84/MMBtu [$5.31/MMBtu plus 10% for low initial volume]).

(b)

Maintenance has not been an issue with WD1 and WD2 as their use has been very little since the 2006 Resource Plan was completed. This was discussed with YEC's lead hand mechanical maintenance. It was noted that after virtually each monthly mandatory startup of these engines small component failures and engine oil and coolant leaks have to be fixed. Capital expenditures have also been minimal as they were identified in the 2006 Resource Plan as needing either life extension or replacement. The common cooling water pump for all three Mirrlees was replaced as a capital project in 2008 at a cost of $31k.

The issue is reliability of grid reserve capacity. Backup generating units must be reliable, i.e., when you need them, they must not fail to start or operate effectively. Planning of reserve capacity is critical to having a reliable source of supply for an isolated grid such as is the case in Yukon.

The 2011 Resource Plan identified the need to begin planning to replace WD1 and WD2 based on the experience gained in refurbishing the same manufacture's engines in WD3 and FD1.

Please note that capital expenditure for the last 10 years are provided in YUB-YEC-1-37(c). Maintenance expenditures are tracked on a plant basis and therefore costs for individual units are not available.

(c)

The referenced statement provided YEC's assessment that the estimated capital cost today to extend the life of the two Mirrlees (WD1 and WD2) was expected to be at least $50% of $1.5 million per MW (i.e., 50% of the cost of a new engine in an existing facility without extensive balance of plant cost requirements such as are expected to be required at the WTGS today), or at least $6.75 million (9 MW at $0.75 million per MW).

This cost per megawatt is higher than the $0.5 million per MW incurred during the rebuild of WD3 but since the work was completed in 2011, labour (both YEC internal and external) and parts costs have increased significantly. Higher costs are also anticipated for WD1 and WD2 based on the recent preliminary engineering work done to assess

balance of plant work needed to install two Wartsila dual fuel units in the WD1 and WD2 service bays.

(d)

The full WTGS Balance of plant work will be required when the old diesel units are replaced with new units. However, some balance of plant work is required to life extend WD1 and WD2 due to deteriorating foundations and end of life of other off-engines systems as reviewed in IR YUB-YEC-1-13(c).

(e)

The balance of plant feasibility report is attached.

(f)

The reasons for the changes in the 2006 Resource Plan recommendation to this Application are based on the lessons learned from refurbishment of the WD3 and FD1 Mirrlees engines as detailed in the Application on pages 25 and 26 as well as completion the Diesel plant Balance of Plant study that indicated considerable costs would have to be incurred for the off-engine infrastructure in the plant to life extend or replace WD1 and WD2. Furthermore, life extension of the 9 MW's of Mirrlees would be insufficient to meet reserve capacity requirements by as early as the winter of 2016/17.

(g)

This change has no impact on the requested overhaul expenditures in the 2012/2013 GRA as none of the costs applied for in the GRA related to the units WD1 and WD2 that are designated for replacement under the current Project. The overhauls in the GRA are required for other units in accordance with YEC policy.

(h)

YEC experience with the refurbishment of two Mirrlees units (WD3 and FD1) demonstrated that support for these units, both from the OEM and after-market suppliers is questionable and not likely to improve. Long delays in ordering parts, issues with quality control and lack of support in the maintenance of these 46 year old engines all

contributed to the decision to view replacement as the preferred option over refurbishment. The foundations under WD1 and WD2 continue to degrade.

(i)

Please see response to YUB-YEC-1-13(c).

(j)

YEC elected to focus initial Mirrlees refurbishments on FD1 and WD3 in order to gain experience, and deferred expenditures on the other Mirrlees units until there was a confirmed need to deal with a forecast capacity planning shortfall. These two Mirrlees were also installed two years later than WD1 and WD2 and were in better condition than WD1 and WD2. The refurbishment or replacements were identified in the 2011 Resource Plan as planned for 2014 for WD1 and 2015 for WD2. Since completion of the 2011 Resource Plan, the current fuel conversion Project was identified as a viable option in response to the forecast capacity planning shortfall that could be done within the same timeframe and provide net savings for ratepayers compared to all other options.

(k)

No significant upgrading of the WD powerhouse was undertaken as part of the WD3 refurbishment in recognition that significant upgrades would be undertaken in the future as required.

(l)

The WD3 refurbishment was completed in 2011 at a cost of $1,901 million. The life extension is expected to extend the life of the unit until 2021 (i.e. by 10 years).

(m)

Extending the life of units by 10 years would not provide the forecast reserve capacity required beginning the winter of 2015/16 in the low or base scenario as indicated on page 22 of the application. Thus extending the life would buy 2 years at most.

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Whitehorse Power Plant P126 Conversion and Upgrade
STAGE 1 - WD1 and WD2 Replacement
Final Report and Cost Estimate

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YUKON ENERGY CORPORATION
Whitehorse (Yukon)

YUKON ENERGY

Whitehorse Power Plant P126 Conversion and Upgrade

Stage 1 – WD1 and WD2 Replacement

Final Report and Cost Estimate

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EXECUTIVE SUMMARY

The capital costs are estimated at $30,390,582, for the replacement of WD1, WD2, and building modifications at the P126 power plant in Whitehorse (including an 18% contingency). The project will result in a duel-fuel capability (Natural Gas-Diesel) at P126, along with a capacity increase of approximately 5 MW. The following were developed for the estimate:

- Project Scope Description;
- Preliminary Process Flow Diagram;
- Preliminary General Layout Sketch;
- Preliminary Project Schedule.

Summary of the Capital Cost Estimate

From a technical perspective, the general concept is well developed and there are no major concerns. However, there are two (2) non-design elements that require close consideration going forward, which are the freight of the generators and the project schedule.

BBA

Yukon Energy Corporation
Whitehorse Power Plant (P126)
WD1 and WD2 Replacement

Costs Summary

Document :	Summary cost report
Revison :	R02
Description :	Conventional Project Mode
Date :	2013-02-21
Project :	5954018
Client project no. :	
Prepared by :	Christian Gagnon
Checked by :	Christophe Desage

Direct costs summary

	Total Material	Total Labour	Total
Supply of Generators and Auxilia	11,000,000 $	0 $	11,000,000 $
Installation Contract	1,426,112 $	3,408,369 $	4,834,481 $
Electrical - High Voltage	613,540 $	92,540 $	706,080 $
Contingency	2,062,617 $	683,416 $	2,746,033 $
Direct costs total:	15,102,270 $	4,184,325 $	19,286,594 $

Indirect costs summary

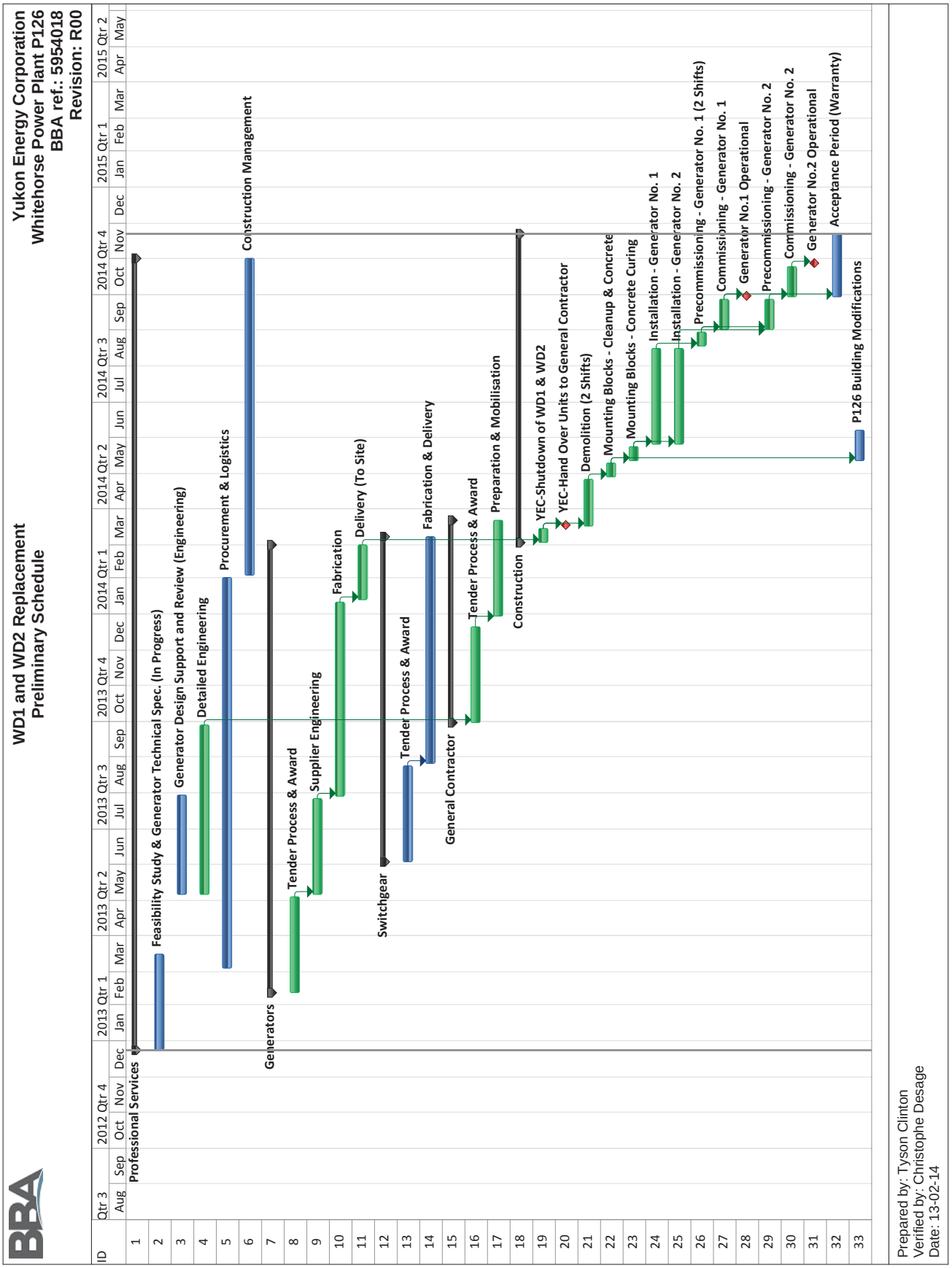
	Total Expenses	Total Labour	Total
Commissioning and Start-Up	20,000 $	320,000 $	340,000 $
Professional Services	280,000 $	3,301,200 $	3,581,200 $
Owners Cost	1,003,000 $	1,351,030 $	2,354,030 $
Freight	2,733,430 $	0 $	2,733,430 $
Spare Parts and First Fill	210,000 $	0 $	210,000 $
Contingency:	890,226 $	995,101 $	1,885,327 $
Indirect costs total	5,136,656 $	5,967,331 $	11,103,987 $
Grand Total:	20,238,926 $	10,151,656 $	30,390,582 $

Schedule

The schedule developed for the project is tight and there is minimal room for slippage. The first unit is foreseen to be in service as of October 1, 2014, with the second unit coming online approximately one month later.

March 1, 2014, the date in which the Mirrlees are to be shutdown has been identified as a critical date within the schedule. This date represents the boundary between the pre-construction and construction phases of the project, both of which have interdependent critical paths. It is paramount that the initial award of the generator supplier contract be completed by early May 2013 to ensure that the project schedule is preserved.

March 1, 2014 is also a significant date as this is when the new units are foreseen to arrive on site. This is important from a risk management perspective as the new units need to arrive on site before the exiting machines are taken off-line.


WD1 and WD2 Replacement
Preliminary Schedule
Yukon Energy Corporation
Whitehorse Power Plant P126
BBA ref.: 5954018
Revision: R00
Professional Services
Feasibility Study & Generator Technical Spec. (In Progress)
Generator Design Support and Review (Engineering)
Detailed Engineering
Procurement & Logistics
Construction Management
Generators
Tender Process & Award
Supplier Engineering
Fabrication
Delivery (To Site)
Switchgear
Tender Process & Award
Fabrication & Delivery
General Contractor
Tender Process & Award
Preparation & Mobilisation
Construction
YEC-Shutdown of WD1 & WD2
YEC-Hand Over Units to General Contractor
Demolition (2 Shifts)
Mounting Blocks - Cleanup & Concrete
Mounting Blocks - Concrete Curing
Installation - Generator No. 1
Installation - Generator No. 2
Precommissioning - Generator No. 1 (2 Shifts)
Commissioning - Generator No. 1
Generator No.1 Operational
Precommissioning - Generator No. 2
Commissioning - Generator No. 2
Generator No.2 Operational
Acceptance Period (Warranty)
P126 Building Modifications
Prepared by: Tyson Clinton
Verified by: Christophe Desage
Date: 13-02-14

Freight

Overall freight for the mandate is approximately 9% of the project cost; with freight of the generators representing approximately 75% of this cost. As freight represents a significant cost it is important that appropriate attention be given to this element to ensure that this cost is optimized.

Two (2) freight options were retained as being potentially feasible for the delivery of the new units:

1. Ship to Vancouver – Air to Whitehorse;
2. Ship to Skagway – Road to P126.

With the information available to date, only one of the above options has proven to technically be an option; (ship-air). However, it is important to note that even though the second option has shown a few issues, it is still worth pursuing at this stage.

TABLE OF CONTENTS

1. INTRODUCTION 1

1.1 General 1

1.2 Existing Plant 1

1.3 Estimate Scenario for Stage 1 2

2. COST ESTIMATE 3

2.1 Overview of Cost Estimate 3

2.2 Contingency 4

2.3 Estimate Sources 5

2.4 Cost Estimate 5

3. DIRECT COSTS - BASIS OF ESTIMATE 6

3.1 Supply of New Generators and Auxiliary Equipment 6

3.1.1 New Generators 6

3.1.2 Auxiliary Equipment 7

3.2 Installation 8

3.2.1 Demolition 8

3.2.2 Installation of New Generators 9

3.2.3 Diesel System 10

3.2.4 Natural Gas System 11

3.2.5 Lubricating Oil System 11

3.2.6 Compressed Air System 11

3.2.7 Cooling System 12

3.2.8 Ventilation Systems 14

3.2.9 Exhaust System 15

3.2.10 Water Treatment System 16

3.2.11 Heating & Heat Recovery System 16

3.2.12 Automation Installation 17

3.2.13 Electrical Installation 18

3.2.14 P126 Building Modifications 18

3.3 Electrical High Voltage 20
3.3.1 6.9 kV Switchgear and HV Cables 20
3.3.2 Step-Up Transformers T2 & T4 22
3.4 Commissioning and Start-Up 24

4. INDIRECT COSTS - BASIS OF ESTIMATE 24
4.1 Professional Services 24
4.2 Owner's Costs 24
4.3 Freight 25
4.3.1 Freight of Generators 26
4.3.2 Transport of Auxiliary Equipment and Material 27
4.3.3 Transport and Disposal of Mirrlees 27
4.3.4 General Freight Conclusions 28
4.4 Spare Parts and First Fill 28
4.5 General Notes on Indirect Costs 29

5. GENERAL ESTIMATE EXCLUSIONS 29

6. PRELIMINARY SCHEDULE 30

7. GENERATOR SUPPLIERS 31

APPENDICES

Appendix A – Preliminary Process Flow Diagram
Appendix B – General Arrangement Sketch
Appendix C – Estimate References
Appendix D – Freight References
Appendix E – Generator Supplier References
Appendix F – General Contractor References
Appendix G – Cost Estimate
Appendix H – Preliminary Schedule
Appendix I – P126 Building Modification References
Appendix J – Mounting Block References

1. INTRODUCTION

1.1 General

Yukon Energy Corporation (YEC) is currently in the process of evaluating their options to extend the life and capacity of their P126 diesel generator plant. As part of the plant upgrade, Natural Gas will be made available that YEC plans to use as a fuel source for its generators (e.g., via dual-fuel equipment).

YEC plans to undertake the P126 modification in two (2) stages, which can generally be defined in the following manner:

Stage 1 – Replacement of WD1 and WD2 with two (2) 6.7 MW dual-fuel units, along with modification to the auxiliary infrastructure required for the operation of these units. Also included in this phase are the structural modifications required to bring P126 within the 2010 National Building Code's (NBCC) seismic standards.

Stage 2 – Replacement of WD3 with a dual-fuel unit along with the conversion of WD4 through WD7 to dual-fuel. Also included in this stage is modification to the auxiliary infrastructure required for the operation of these units and plant modification required to feed a proposed district heating system.

This study/estimation is for the work foreseen for Stage 1; analysis associated with Stage 2 will be in a separate report.

1.2 Existing Plant

The YEC Whitehorse Diesel Power Generating Plant (P126) currently houses seven (7) diesel-fuelled generator units. The plant was initially commissioned in 1968 and included two (2) Mirrlees units (KV12 MAJOR 3.9 MW and KV16 MAJOR 4.7 MW) and was later expanded in 1970 to incorporate the third Mirrlees unit (4.7 MW). In 1975, a plant expansion was completed that included two (2) EMD 20-645 units (2.6 MW) and increased the plant capacity by 5.2 MW. The last major expansion occurred in the early 1990s and included the addition of a third EMD 20-645 unit (2.5 MW) and one CAT 3612 unit (3.3 MW), which increased the installed capacity by 5.8 MW. The total installed capacity of the plant is 24.3 MW.

1.3 Estimate Scenario for Stage 1

Stage 1 will include the replacement of two (2) Mirrlees units (WD1 & WD2) with two (2) simple cycle reciprocating dual-fuel (diesel and natural gas) units with a capacity of 6.7 MW each. Also included within Stage 1 is the analysis of the existing P126 building structure and any modifications that might be required to bring the building to conformance with the 2010 NBCC seismic code for post disaster buildings and the infrastructures associated with the new WD1 and WD2 units, including:

- WD1 & WD2 Mounting Blocks;
- Mirrlees Bay Air Handling System;
- WD1 & WD2 Cooling System;
- WD1 & WD2 Auxiliary Equipment;
- T2 & T4 Switchgear;
- T2 & T4 High Voltage Cables and Equipment.

For project delivery, YEC will need to enter into commercial relations with four (4) primary groups from a supply installation services perspective:

- Generator Supplier;
- General Contractor;
- Switch Gear Supplier;
- EPCM Professional Services Provider.

Below is a breakdown of responsibility for the primary supply of services and material for each party:

Generator Supplier

- Supply two (2) generator units;
- Supply all generator auxiliary systems;
- Transport of generator units & auxiliary systems to Vancouver;
- Commissioning & start-up.

General Contractor*

- Demolition, removal and disposal of existing systems and equipment;
- Transport of generator, auxiliaries and materiel from Vancouver to Whitehorse (P126);

- Installation of new generator units;
- Installation of new generator auxiliary equipment;
- Installation and material supply for interconnection of generator auxiliary equipment;
- Installation of new switchgear;
- Installation and material supply for interconnection of all high voltage equipment and cabling;
- Installation and material supply for all modifications to superstructure of P126, with respect to the NBCC's seismic standards;
- On-site Heath & Safety services, on-site receiving & warehousing facilities, site services for the workers, etc.

*****General Contractor will be responsible for all civil, structural, electrical, automation, mechanical work commissioning and start-up associated with the above.

Switchgear & MCC Supplier

- Supply of one (1) 6.9 kV switchgear;
- Delivery of one (1) 6.9 kV switchgear to P126;
- Supply of one (1) MCC cabinet;
- Delivery of one (1) MCC cabinet.

EPCM Professional Services Provider

- Provide engineering services;
- Provide geotechnical services;
- Provide procurement services;
- Provide construction management services.

2. COST ESTIMATE

2.1 Overview of Cost Estimate

The capital costs are estimated at $30,390,582, for the replacement of WD1, WD2, and building modifications at the P126 power plant in Whitehorse (including an 18% contingency). The estimate provides a preliminary capital cost forecast to support the assessment of the project's profitability potential. As such, this estimate forms the initial

"control estimate" against which subsequent cost estimates developed in the engineering phases will be compared and monitored accordingly.

The guidelines applied to this capital cost estimate allow for and/or are based on the following:

- A common basis of the concepts involved with classifying project cost estimates, regardless of the type of facility, process or industry to which the estimates relate;
- Full definition and correlation of the major characteristics used in classifying cost estimates so that companies can unambiguously determine how their practices compare to the guidelines;
- A measured degree of project definition and degree of engineering completion as the primary characteristic to categorize estimate classes; and
- Reflects generally accepted practices in the cost engineering profession.

To support the estimation, the overall engineering for the project was developed to approximately 5% which resulted in the development of the following elements:

- Project Scope Description;
- Preliminary Process Flow Diagram;
- Preliminary General Layout Sketch;
- Preliminary Project Schedule.

2.2 Contingency

The contingency for the project was determined by applying a contingency on each element of the estimate. The applied contingency varies between 15% and 40%, however, typically 20% was applied to most elements within the estimate. The contingency provides an allowance for modification variances from undeveloped details within the capital cost estimate for this level of study. This amount does not cover price escalation, currency fluctuations, changes in the scope of the project or schedule changes due to labour disruptions and weather impediments.

2.3 Estimate Sources

A number of factors were taken into account for the development of this estimate, such as:

- Date, currency and exchange rate;
- Labour rates and labour productivity factors.

All of which were built into the labour rates that were used in the estimate.

Refer to Appendix A for details on the above.

2.4 Cost Estimate

The detailed cost estimate can be found in Appendix G. Refer to the Basis of Estimate sections of the report for technical details on the projects direct and indirect costs.

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Yukon Energy Corporation
Whitehorse Power Plant (P126)
WD1 and WD2 Replacement

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Grand Total:	20,238,926 $	10,151,656 $	30,390,582 $

3. DIRECT COSTS - BASIS OF ESTIMATE

An overall portrait of the generator systems/equipment to be installed can be found in the preliminary process flow diagram (5954018-000000-49-D10-0001-RAA), which is in Appendix A. Additionally, a preliminary general arrangement (sketch) (5954018-45-D09-0001-RAA) can be found in Appendix B. It is important to note that the engineering for this project is only developed to about 5% thus many of the details presented in this report are subject to change as the project develops.

Redundancy

P126 operation criteria is the following:

- N+1 redundancy;
- Maximum load loss expectation of 2 hours;
- 90% reliability.

Each new generator is able to operate independent from the other units in the plant and are to include a minimal number of common systems between units. New generator systems have been designed considering that redundancy will come from other generator units in the plant (i.e., minimal back-up pumps, motors, etc.). In the cases where there are common equipment/units between generators redundancy was added within these systems. Maintenance downtime was also considered when evaluating redundancy requirements.

The following sections provide more detail on the systems to be installed along with details on installation.

3.1 Supply of New Generators and Auxiliary Equipment

3.1.1 New Generators

Two (2) Wärtsilä 6.7 MW generators, model 16V34DF, are considered for the cost estimate. These units will physically fit on existing mounting blocks. Pricing was obtained from the budgetary proposal from Wärtsilä that dates from June 22, 2012. This proposal was for three (3) units; a revised price for two (2) units and clarifications on the original quotation was provided by Wartsila January 25, 2013 (refer to Appendix E for the original quotation and clarifications).

3.1.2 Auxiliary Equipment

All auxiliary systems are to be supplied with the generators. Below is a list of systems included:

- Exhaust Systems;
- Cooling Systems;
- Diesel Systems;
- Natural Gas Systems;
- Lubricating Oil Systems;
- Compressed Air Systems;
- Air Intake Systems.

Refer to Installation sections for the following information on the above systems:

- System description;
- Details on materials and labour required for interconnection and installation of system components.

Freight

Wärtsilä's budgetary quote indicates that they would provide delivery to a port of choice in Canada and have confirmed that Skagway, Alaska could be considered as a delivery point. Refer to Freight Section (in Indirect Costs) for details on the transportation of the generator units.

Estimate Note: The cost for auxiliary systems is included in the generator price; the cost for the installation and interconnection of systems along with Installation of the generators can be found in the installation section of the estimate. It should be considered that the auxiliaries system be delivered on skids, as far as is possible, in order to limit on-site assembly of subsystems or accessories. The cost for the delivery of the units to a Canadian port of choice (which includes Skagway) is included in the price of the generator units.

3.2 Installation

All installation will be done by the General Contractor; responsibility for supply of material is indicated on the PFD.

Installation Notes

The following conditions are considered for the estimate:

- WD3 will not be in operation during the demolition and installation activities.
- The Mirrlees units will be shutdown as March 1, 2014 and will be available for demolition to the General Contractor by March 15, 2014.
- Adequate laydown, storage, administrative space will be made available to the General Contractor on site.

Estimate Note: When the General Contractor is not responsible for the supply of the material, only the installation costs will be included in the installation section of the estimate.

3.2.1 Demolition

WD1 and WD2, along with all the auxiliary equipment, will be removed and disposed of off site. Below is a list of equipment/systems to be removed:

- WD1 Unit & Alternator;
- WD2 Unit & Alternator;
- Mirrlees Bay Ventilation Systems Exhaust Systems (WD1 & WD2);
- Cooling Systems, including Heat Recovery (WD1 & WD2);
- Diesel Systems (WD1 & WD2) (Day Tank will remain for WD3 requirements);
- Lubricating Oil Systems (WD1 & WD2);
- Compressed Air Systems (WD1 & WD2);
- Removal of Mezzanine in Mirrlees Bay.

Unless otherwise stated, all system components will be removed along with all associated bases, supports, electrical equipment (MCCs, cables, etc.) and automation systems. Drainage and disposal of all system fluids will be included in the Contractor's demolition scope.

Demolition Notes

- It was considered that no more than a minimal amount of asbestos can be present, which could be removed without employing elaborate removal procedures. (i.e., via "the bag and glove method").
- Large cranes will not be required to move material; it is anticipated that all handling will be done using small cranes, rolling platforms and hydraulic systems.
- It is anticipated that all equipment/systems to be removed will be isolated by YEC employees prior to demolition (this cost is not included in the estimate).
- YEC will retain certain components for maintenance of WD3 no credit/value has been included in the estimate for recovered material.
- Removal of water lines (for cooling) between hydro and P126 is not part of the demolition scope. Lines associated with WD1 and WD2 will be capped, system will remain in operation for WD3.
- No earth removal or soil decontamination is considered in the demolition scope.

Estimation Note: The cost for the transport and disposal of material has been included under Freight.

3.2.2 Installation of New Generators

Installation includes the following:

- Installation and assembly of two (2) generator units;
- Mounting block modifications.

Estimate Note: The cost for the interconnection of generators to auxiliary systems is included in the installation costs for the respective system. The cost freight and manipulation of the two units, auxiliary systems, and materials to site is included in the Freight section of the estimate.

Mounting Block

The analysis results for the mounting blocks indicate that, based on the soil assumptions and with properly functioning spring packs to ensure the target transmissibility levels required by the supplier, the new Wärtsilä units could be operated on the existing mounting

blocks and should not prove to be problematic for vibrations. Some transient vibrations may occur during start-up and shut-down, due to the proximity of the second modes of vibration to the operating frequency. The addition of viscous dampers to the spring packs would help to reduce these effects, especially for the horizontal vibration components.

These analysis results could be confirmed during a later phase, once measured, in-situ soil parameters are made available.

Modifications to mounting blocks will only involve the filling of cavities with reinforced concrete or non-shrink grout to receive the new units.

Refer to Appendix J for complete details regarding mounting blocks.

3.2.3 Diesel System

System Description

There will be an independent diesel system for each unit (i.e., two (2) systems) that will connect to the main diesel supply line. The following will be included in the system for each unit:

- One (1) diesel transfer pump unit and filters;
- Automated shut off valves;
- One (1) oil flow meter for total fuel consumption measurement;
- One (1) fuel cooler/return system;
- One day tank (double-walled);
- All piping and valves inside engine hall.

The following are excluded from the estimate:

- Main fuel tank;
- Piping and valves outside the engine hall.

Diesel System Notes

- The design incorporates three (3) independent day tanks to reduce the risk of cross contamination between units.

- A common transfer pump is included in estimate between the main reservoir and plant diesel network (system is currently gravity fed).

3.2.4 Natural Gas System

The gas system will be a 75 psig CSA approved distribution network from the plants mainline (within engine hall) to each of the new units. The following will be included in the system:

- Two (2) gas trains (supplied on skid by generator supplier);
- Automated shut-off valves;
- Two (2) gas flow meters;
- One (1) leak detection system;
- Interconnection points for future supply of other generators (i.e., for WD3 – WD7);
- All piping and valves inside the engine room.

The following is excluded from the estimate:

- Natural gas distribution network outside the building envelope.

3.2.5 Lubricating Oil System

There will be two (2) common Lubricating Oil Systems for WD1 & WD2 and will be sized to meet the future needs of WD3:

- New Oil System;
- Used Oil System.

Each system will contain a storage reservoir. The new oil system will provide an automated make-up for the units, which will be in the range of 75 L/day.

3.2.6 Compressed Air System

System Description

The compressed air system will consist of two (2) independent systems:

- Instrument Air (125 psig);
- Starting Air (435 psig).

Both air systems will be common for the two (2) new generators and will be sized to meet the needs of the future WD3 unit.

The instrument air system will include the following:

- Two (2) multi-stage compressors;
- Air dryers;
- Two (2) Instrument air tanks;
- All piping and valves inside engine hall.

The starting air unit will include the following:

- Two (2) multi-stage compressors;
- Air dryers;
- Two (2) starting air tanks;
- All piping and valves inside engine hall.

Air System Notes

- Starting air system will have the capacity for three engine start attempts.
- As a back-up to the instrument air system a tie-in between to the starting system could be added; this would remove the need for a redundant instrument air compressor. This detail will be refined in the next phase of engineering.

3.2.7 Cooling System

System Description

Each generator will have its own independent cooling system that will cool the high temperature (HT) and low temperature (LT) circuits of the units. Each generator system will consist of three (3) loops:

- Two (2) that circulate through the engine;
- One (1) that transfers heat to the air coolers.

There will be two (2) plate heat exchangers to interface between the motor and air cooler loops. The medium for the engine loops will be water with a rust inhibitor and the medium in the air cooler loop will be a glycol mixture. Heat from the system will be dissipated into the

environment via air coolers that will be installed outside on the "east" side of the Mirrlees hall (i.e., next to air coolers for other units). A heat recovery system will be connected to the cooling systems (refer to heat recovery system for details). The following are included in the cooling system for each generator:

- Three (3) pumps;
- Air coolers (external);
- Two (2) interface plate heat exchangers (i.e., for HT and LT);
- One (1) LT and one (1) HT expansion tank;
- One block heater and pump;
- All piping and valves.

The following are excluded from the estimate:

- Plate heat exchanger for heat recovery (included in heat recovery);
- All valves and piping associated with heat recovery (included in heat recovery);
- Glycol expansion tank (included in heat recovery);
- Glycol (included in heat recovery).

Cooling System Notes

- As these systems are relatively customizable, space for the exterior cooling units should not be an issue. Upon preliminary evaluation, the air coolers should fit on the ground in line with each unit. If this space proves not to be adequate, the units could alternately be mounted on the roof of the plant. This estimate assumes space will be found at ground level for the units.
- Currently, all three (3) Mirrlees are cooled with river water. The following are the three (3) main reasons why this practice was changed:
- Environmental concern of contaminating river water (this concern also makes the option cost prohibitive).
- Reliability concerns during cold periods; this system has been known to freeze up, as was the case when we conducted our site visit.
- Capacity concerns of the existing infrastructure between the river and the units.

WD3 will continue to be cooled with river water until it is replaced.

3.2.8 Ventilation Systems

System Description-Combustion Air

Each generator will have its own dedicated ventilation system consisting of a supply fan and an exhaust fan. The supply fan will be sized to supply the required amount of combustion air, as well as the ventilation air necessary to maintain the plant at a comfortable temperature (25°C) while the generators are in operation. The exhaust fan will be selected in order to maintain a slight positive pressure in the plant at all times during operation. Both fans will be controlled in order to maintain temperature and pressure within predetermined limits. The intake air for all supply fans will be heated via the heat recovery system network, which has a tie-in with the plants existing heating network for periods when not enough recovered heat is available.

The following are included in the Combustion Air System for each unit:

- Supply fan;
- Exhaust fan;
- Heating coil;
- All duct work and dampers.

The following is excluded from the Combustion Air Systems:

- All piping and valves associated with the heat recovery system (included in heat recovery).

System Description-Building Air

An independent ventilation system consisting of a supply and exhaust fan will also be installed in the plant in order to supply the space with the minimum required amount of air while the generators are not in operation. The supply and exhaust fans will be installed at opposite sides of the building. The intake air for the supply fan will be heated via the heat recovery system network, which has a tie-in with the plants existing heating network for periods when not enough recovered heat is available.

The following are included in the Building Air System:

- Supply fan;
- Exhaust fan;
- Heating coil;
- All duct work and dampers.

The following is excluded from the Building Air System:

- All piping and valves associated with the heat recovery system (included in heat recovery).

Ventilation System Notes

- The existing ventilation system in the Mirrlees room is insufficient for the existing units and for the new generators. This system is installed on the mezzanine, which will most likely interfere with the new generators. Additionally, fresh air is blown onto the front end of the engine rather than the alternator, which is not inline with best practice.
- As the existing Mirrlees currently take their combustion air from within the building all the three (3) systems will be replaced at the same time. The combustion air system for WD3 will be sized for the future WD3 unit.
- These systems were not presented on the general arrangement drawing as the concept for these systems is especially susceptible to change. The concept that was used to develop the estimate takes the combustion air from within the building however a possible alternative system is to directly duct the combustion air from the exterior. Additionally space is limited on the “west” wall which may require the systems to be installed on the outside of the building.

3.2.9 Exhaust System

System Description

Each new generator will have its own independent exhaust system. The new stacks will be insulated (interior section only) and approximately 15 m high (exact stack height to be confirmed in a later phase based on dispersion study results). The following are included in the each Exhaust System:

- Silencer (hospital grade);
- Bellows;
- Rupture disks;
- Insulation;
- Structure (to be supplied by General Contractor);
- Concrete base (to be supplied by General Contractor);
- Ducting.

The following is excluded from the system:

- Heat Recovery (space will be foreseen to connect an exhaust boiler in the future).

3.2.10 Water Treatment System

The water treatment system would be used to treat water available at P126 for cleaning of the turbos. There would be one (1) common water treatment system for all three (3) units. At this point it has been considered that a water treatment system would be necessary, however, future water quality tests may confirm that this system is not required.

3.2.11 Heating & Heat Recovery System

A heat recovery system will be installed to collect heat from the LT and HT circuits of the engines and distribute it to the following equipment:

- Combustion air;
- Building air;
- Existing dyke heating system;
- Existing unit heaters;
- LNG vapourizer;
- Generator heaters.

The recovery system will include an interface with the plants existing heating system. This would be for periods when heat available from the recovery system is not sufficient. The medium within the system will be a glycol mixture. The system will include the following:

- Two (2) interface heat exchangers (between Cooling Loop and Heat Recovery Loop of WD1 and WD2);
- One (1) common glycol expansion tank (this tank will service Heat Recovery & Glycol Cooling loops for WD1 and WD2);
- One interface plate heat exchanger (with existing heating network);
- All Piping and valves within heat recovery network.

Heat Recovery System Note

- There is still much optimization to be done in the heat recovery network. The above scenario was developed for the cost estimate but will most likely be modified in future phases of the project.

3.2.12 Automation Installation

Instrumentation and control systems of the newly installed systems will send a signal to the plants existing SCADA/PLC system. Each generator set will have one (1) control panel, including push buttons and pilot lights, PLC with processor, communication, and I/O modules. An additional control panel common to all generator sets will also be included for the auxiliary systems. All instruments and controls for generator sets and auxiliary systems will be prewired on their respective skid, with signals brought to a common interconnection terminal block. The Generator Supplier or OEM will supply all required hardware. The following are included in the Automation Package:

- Installation of three (3) pre-mounted Control Panels with their PLC;
- Installation of three (3) HMIs (two (2) operator workstations and one (1) engineering work station);
- Interconnection of all system components;
- Programing and System Configuration & Integration.

The following are excluded from the Automation Package:

- Programming for new plant operational strategy;
- Industrial IT Systems;
- Hardware (supplied by generator set OEM).

3.2.13 Electrical Installation

Electrical - Low and Medium Voltage

The Contractor will be responsible for the installation of electrical components required to energize new electrical equipment from the plant's existing electrical network. Responsibility of supply is indicated by the following:

This package will include:

- One (1) MCC line-up (MCC #1, for WD1, WD2, WD3 and P126 auxiliary loads);
- One (1) 600 A circuit breaker, located in the P126 station services switchboard panel (MCC #1 main circuit breaker);
- All cabling and electrical equipment for the interconnection of new electrical equipment (600 V/120 V).

Electrical - Low and Medium Voltage Notes

- The complete MCC #1 lineup will be replaced. It is assumed that only WD1 and WD2 cables will be replaced. All the other existing cables will be reused. This estimation also includes the replacement and/or the installation of new cable trays and drops for all the WD1 and WD2 associated auxiliary equipment, which are connected to MCC #1.
- An auxiliary load increase in MCC #1 is anticipated, but has not been quantified yet. The replacement of the actual 400 A MCC #1 main circuit breaker by a 600 A, located in the P126 stations services switchboard, is covered in the cost estimate.

3.2.14 P126 Building Modifications

As part of this study, the following activities were completed for the verification of the structural conformance of the building to the NBCC 2010 seismic requirements:

- Review of previous reports from GEA;
- Review of 2010 NBCC requirements and Part 4 - Commentary L for existing buildings;
- On-site structural audit and review of existing conditions;
- Construction of structural analysis model, elaboration of input loads and analyses;
- Elaboration of structural modifications and reinforcing schemes.

A detailed description of the code review and corresponding structural analyses can be found in Appendix I.

The on-site structural audit was done to provide BBA structural designers with the information required for proper structural analysis of the building. As the profile sections and thicknesses were not available on the original design drawings, thickness and dimensional measurements were taken for the main portal frames, bracing elements and roof and cladding support elements (girts and purlins).

The building's main frames are rolled, structural steel sections, while the secondary frame members, such as girts and purlins are cold-rolled. The bracing elements consist of 5/8 in. diameter rods attached to the frames with turnbuckles. This type of construction is typical of pre-engineered buildings.

During the site audit, it was noted that portions of the wall bracing system and all of the roof bracing system for the 1968 building were either never installed or subsequently removed. One bracing had been cut, probably due to requirements for mechanical equipment installations. Although the original drawings for the 1974 portion were not available, it is probable that a bracing on the east face is also missing, as there is one installed on the west face (between grids VIII and IX), and bracing systems are usually designed in tandem to avoid building torsion. Finally, it was also noted that some girts were missing on the east face, between grids V and VII. These girts, although not considered as structural elements because they are cold-rolled, still contribute to reduce the effective length of the columns.

As can be seen in Appendix I, it was judged crucial to evaluate the 1968 original design in order to observe the building's behavior as compared to its "as-built" condition. The analysis concluded that the original design was structurally sound and respected the 1965 code requirements. Only the bracing rods were found to be non-conforming to the structural steel design standards, as they were too slender for their length, even though they were strong enough to take tension loads. The second phase of analysis consisted in the review of the combined 1968, 1974 and 1991 building in its "as-built" condition as noted during the site audit. Loads used were the applicable benchmark snow, wind and seismic loads, except for the 1968 segment, where the 2010 seismic loads were applied. Load combinations and load

factors applied are the 2010 factors required for post-disaster buildings. Results indicate that because of the missing bracings in the 1968 and 1974 portions, torsion is induced into the building's system, causing some columns and bracings to fail with respect to code strength requirements. Although this does not necessarily mean that the building is collapsing, it does imply that if ever it is submitted to the ultimate design loads applied, these elements could fail. It should also be noted that under the load combination for Dead + Wind applied, a deflection of 2 in. is shown to occur at the top of column VII, which is much more than the recommended allowable deflection of 0.6 in.

The final analysis done includes the addition of bracings to ensure proper performance and conformance to the 2010 NBCC requirements for "post-disaster" buildings. The same loads as for the "as-built" model were applied, but bracings were replaced, upgraded and added for proper building performance.

A more detailed explanation of the 2010 code interpretation, analyses and sketches can be found in Appendix I.

In conclusion, it is highly recommended that the modifications to the building be implemented, not only to ensure 2010 code compliance, but also to enhance the building's performance with regards to snow and wind loads.

3.3 Electrical High Voltage

3.3.1 6.9 kV Switchgear and HV Cables

Description of Existing Situation

Unit WD1 and WD2 are connected to the original 1968 switchgear, made by Brush, which was also used for WD3 and the station services. Today this 6.9 kV bus has been split and extended to connect the WD3 to its own step-up transformer and the station services are now supplied from the S-150 substation 34.5 – 0.6 kV transformers SST3 and SST4.

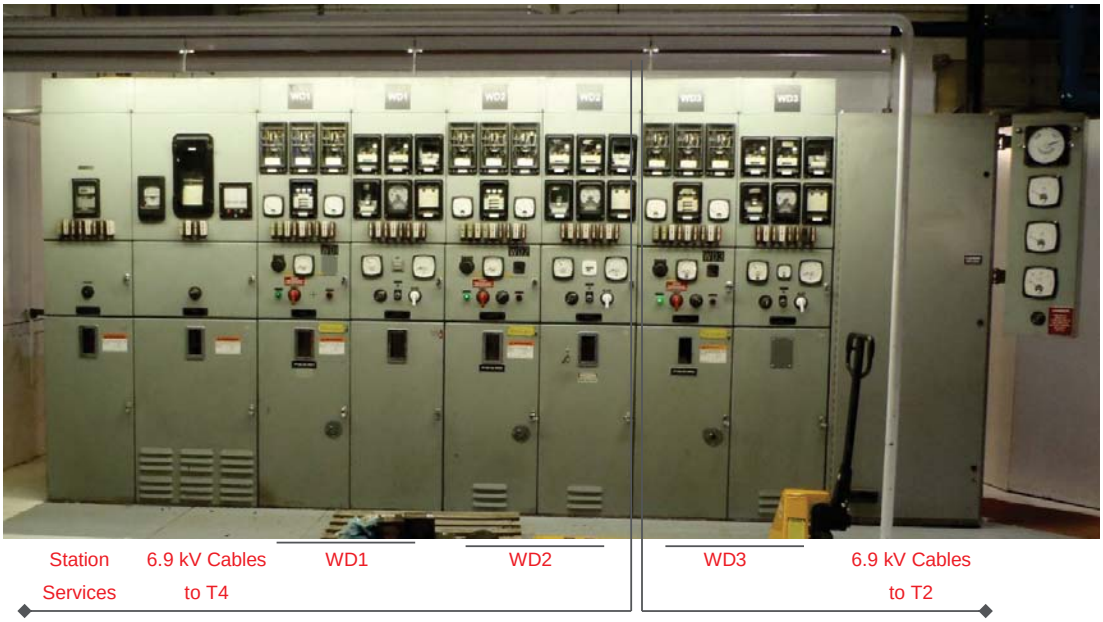


Figure 3-1: Existing 6.9 kV Switchgear

The Brush switchgear is equipped with bulk-oil circuit breakers. Typical service life expectancy for this type of equipment is 35 years and after 44 years of service, this switchgear is obsolete and has to be replaced.

It is not necessary to replace any other electrical component upstream of the P126 switchgear. The size of the power cables between the P126 and the S150 switchgears, as well as the 52-5 circuit breaker rating, are sufficient to cover power increase of the new WD1 and WD2 unit.

Description of New Equipment

The existing switchgear will be completely dismantled to make room for new 6.9 kV switchgear, which will have three (3) circuit breakers (WD1, WD2 and WD3) and five (5) potential transformers. The cables between WD1, WD2 and the new switchgear will be replaced by single phased 15 kV – 1000 MCM cables, while the existing cables connected to WD3 will be reused.

3.3.2 Step-Up Transformers T2 & T4

Description of Existing Situation

WD1 and WD2 are connected to T4, a 6.9-34.5 kV step-up transformer located in the S150 substation. Built by FPE (Federal Pioneer) in 1973, T4 has a nominal rating of 9 MVA (ONAN), up to 12 and 15 MVA with 1 and 2 stages of cooling fans.



Figure 3-2: T4 6.9-34.5 kV Step-up Transformer

The WD3 is connected to T2, a 6.9-138 kV step-up transformer located in the S150 substation. Built by Westinghouse in 1968, T2 has a nominal rating of 12 MVA (ONAN) up to 16 MVA (ONAF) with the installed cooling fans.



Figure 3-3: T2 6.9-138 kV Step-up Transformer

With T4 at 39 and T2 at 44 years of service, they are physically in good condition (no rust, no leaks). Typical service life expectancy for this type of equipment is 45 years, however, many power transformers are still in service without problems after 55 years and even more. Therefore, many users rely on sample oil analysis to follow insulation aging and predict the end of life of power transformers.

The last oil analysis report seems to be in 2010 and shows no sign of insulation aging or degradation. Oil analysis is due since it should be done every year, especially when a power transformer is getting closer to its end of life. However, based on the 2010 results, one can expect another 10-15 years of service with these power transformers. Therefore we see no immediate reason to replace these power transformers in the short term (0-5 years).

Description of New Situation

With WD1 and WD2 at 2 x 6.74 MW (13.5 MW or 16.9 MVA at 0.80 PF), T4 has the required capacity (15 MVA ONAF) but will be fully loaded. With WD3 at 6.74 MW, T2 will be well below its nominal rating of 12 MVA (ONAN). Regular oil analysis will be required to make sure that increased load is not aging T4 too much.

3.4 Commissioning and Start-Up

The Commissioning and Start-Up activities are split into two (2) categories:

- Commissioning Pre-Operational Verification;
- Commissioning Operational Verification.

Cost for the Contractor and Professional Services firm were included in this section of the estimate, cost for the Generator Supplier's involvement were included in the cost of the units. Estimate includes time, material, lodging, and travel for these resources.

Commissioning activities required for new generators, associated auxiliary equipment, MCC, and switchgear are accounted for in this section.

4. INDIRECT COSTS - BASIS OF ESTIMATE

4.1 Professional Services

EPCM services will be required to complete the design, procure the required equipment and services, and manage the construction. The estimate is based on the assumption that all the services would come from one firm.

4.2 Owner's Costs

Owner's cost used in the estimate were provided by the YEC and are separated into the following categories:

- Financing – Accounts for financing during construction period up to start-up date;
- Studies – Cost of previous and current studies (i.e., geotechnical, environmental, preliminary engineering, etc.);
- Management – Accounts for salary, benefits, and expenses of owner's project team personnel, including safety inspector and expenses;
- Commissioning and Decommissioning - Accounts for plant personnel that will be required to support the commissioning of the new units and the shutting down of WD1 & WD2 (which includes recovering certain system components and preparing the units so that they can be handed over to the General Contractor);

- Training – Accounts for the cost to train YEC operators (on site) on the new generators and associated systems to be installed;
- Permits – Account for the physical cost of environmental and construction permits;
- Insurance - Blanket and third-party insurance coverage, required coverage is accounted for in existing policy. General Contractor will provide its own insurance coverage;
- Escalation – Accounts for inflationary costs over the life of the project; a 2% annual rate was applied;
- Public Relations & Legal – Accounts for the cost of legal counsel and public relation activities with respect to the project.

Owner's Costs Notes

The following were considered to be "sunk operational costs" as a result no amount was associated with these activities in the estimate.

- Site maintenance (snow clearing, cleanup, janitorial, etc.);
- Utilities distribution (water, electricity, compressed air, etc.).

4.3 Freight

The cost of getting the generator units to a port of choice (Vancouver or Skagway) has been included in the generator price. It has been considered that all other equipment and material can be sourced or delivered to the lower BC mainland.

The costs included in the freight section of the estimate corresponds to the freight related expenses that would be incurred to get the generators, equipment, and material to site from Vancouver. These freight costs have been broken into two (2) categories:

1. Freight of Generators;
2. Freight of all other Equipment and Material.

4.3.1 Freight of Generators

Weight of generators was a major consideration in the freight; fully assembled the generator units are approximately 120 t each and can practically be broken into two (2) sub-assemblies:

1. Engine (approximately 80 t);
2. Frame & Alternator (approximately 50 t).

The freight analysis for the cost estimate resulted in two (2) freight options that were considered appropriate for the transportation of the generators:

1. Reception of units at Skagway followed by transport by road to site;
2. Reception of units in Vancouver followed by transport to Whitehorse via air freight. (This option was retained for the cost estimate).

Air Freight Option

The air freight option considers delivery of the generator sub-assemblies to the port of Vancouver which would then follow the below sequence of events:

1. Transportation to Vancouver International Airport;
2. Manipulation to load assemblies onto cargo plane;
3. Flight to Whitehorse Airport;
4. Manipulation to transfer from plane to truck in Whitehorse;
5. Transportation to P126.

The weight of the sub-assemblies limited the options available for air cargo; the aircraft required to ship the units to Whitehorse would be an Antonov 124. Due to the length of the runway in Whitehorse, four (4) trips would be required to get the generators to Whitehorse (each sub-assembly would have to be shipped separately).

Skagway to Site Road Option

From Skagway, the units could be delivered via road to Whitehorse, which is a distance of approximately 180 km. Even with the units broken down to their sub-assemblies weight is still a concern due to weight limitations on two (2) bridges along the route (especially the first bridge which is just past the port). It was confirmed that the standard weight limitation for the first bridge is 80 t, the largest sub-assembly is less then the 80 t limit, however, the equipment expected to be used for transport the equipment is approximately 50 t which results in a combined weight that would exceed the bridge limit. An option does exist to transfer the units over the bridge via a rail system, however, this would possibly require all or a portion of the bridge to be closed down for up to three (3) days. As the implications and costs were not able to be confirmed by the issue of the estimate, the air freight option was thus retained for the cost estimate. Another unknown with the road transport option was the road weight limitations during the spring freeze thaw period which may be an issue depending on when the units are expected to be shipped to the site.

However, it is important to note that even though the second option has shown a few issues, it is still worth pursuing at this stage.

4.3.2 Transport of Auxiliary Equipment and Material

The auxiliary equipment, material, and Contractor equipment will be shipped to the site from Vancouver to Skagway via a barge. It is important to note that it was assumed that a significant coordination would be possible to ensure all material could make it onto one barge from a scheduling perspective. In the cost estimate, two (2) return barge trips have been estimated. One to take the equipment and material to the site and another at the end of the project to return the Contractor's equipment to Vancouver.

4.3.3 Transport and Disposal of Mirrlees

It was considered that the two (2) Mirrlees units would be disposed of in the south and would be transported there via a barge. Disposal costs have also been accounted for in the transport costs.

4.3.4 General Freight Conclusions

Overall freight for the mandate is approximately 9% of the project cost; with freight of the generators representing approximately 75% of this cost. There are still a number of factors that need to be investigated with respect to the transportation. It is recommended that YEC allocate resources to this aspect of the project in the next phase to insure that costs surrounding the freight are optimized.

General Freight Notes

- The option of flying the units from Europe to the site was explored but proved to be not feasible as the loaded planes could not cross the at Atlantic without refueling.
- It was confirmed it is not an option to transport the units via rail from Skagway as there is only passenger transport on those tracks.
- There may be an optimization that can be made in the barge transport, i.e., the old Mirrlees unit may be able to be shipped on the empty barge that was used to ship equipment and material to the site. This item should be part of the transportation study to be completed during the next phases of the project.
- YEC had mentioned that there is a port in Haines, Alaska that could be used as a delivery point; the road to Whitehorse is longer, however, there may be fewer concerns with respect to weight issues on bridges. This item should be part of the transportation study to be completed during the next phases of the project.
- Some details on the investigation that was done on the freight can be found in Appendix D.

4.4 Spare Parts and First Fill

Spare parts accounts for all consumable parts for the first six (6) months of operation along with an inventory of non-capital replacement parts for maintenance of the machines. This cost was estimated to be 3% of the cost of one (1) machine. This also accounts for products such as oil, grease, glycol etc., required to perform mechanical completion and checkout of equipment during the construction phase.

Capital Spare parts, diesel fuel and natural gas are not included in the Spare Parts and First Fill.

4.5 General Notes on Indirect Costs

Supplier Services, i.e., services required from major equipment manufacturers for their assistance during the erection, start-up and commissioning phases of the project have been included in the cost of the equipment.

Construction Indirect Costs, which account for all expenses incurred by the Contractor while performing the necessary on-site services, have been include in the cost of the General Contractor included in the direct costs.

The costs include:

- Site offices and trailers c/w associated costs;
- Temporary facilities (warehouse, sanitary, first aid, lay down etc.);
- Site safety and security (infrastructure only - no personnel);
- Maintenance and support services;
- Insurance.

5. GENERAL ESTIMATE EXCLUSIONS

The following cost items are excluded from the estimate:

- All costs incurred as a result of extreme weather conditions;
- Force majeure;
- Major strikes;
- Changes in scope;
- New government regulations;
- Any costs associated with the accelerated delivery of equipment and materials, or premiums necessary to procure items in short supply;
- Contaminated soil excavation/disposal/removal;
- Major asbestos material disposal/removal;
- Working capital;
- Taxes;
- Land acquisition costs.
- LNG plant and natural gas network exterior to the plants building envelope;

- Control systems, other then those directly associated with the control of WD1, WD2, and WD3 generators;
- Building systems and services (i.e., fire suppression, security, telecom, drainage, building electrical, battery and chargers, water, etc.);
- Operational costs.

6. PRELIMINARY SCHEDULE

The schedule developed for the project is tight and there is minimal room for slippage. The first unit is foreseen to be in service as of October 1, 2014, with the second unit coming online approximately one month later.

March 1, 2014, the date in which the Mirrlees are to be shutdown, has been identified as a critical date within the schedule. This date represents the boundary between the pre-construction and construction phases of the project, both of which have interdependent critical paths. It is paramount that the initial award of the Generator Supplier contract be completed by early May 2013 to ensure that the project schedule is preserved.

March 1, 2014 is also a significant date as this is when the new units are foreseen to arrive on site. This is important from a risk management perspective as the new units need to arrive on site before the exiting machines are taken off-line.

Milestone Dates

Below is a list of key milestone dates in the project:

YEC Board Meeting	February 20, 2013
Award Contract for EPCM	April 1, 2013
YEC Board Meeting	May 8, 2013
Award Contract for Generator Engineering	May 10, 2013
Receive First Supplier Documents from Generator Supplier	July 1, 2013
Award Final Contract for Generators	August 1, 2013
Award Contract for Switchgear	August 1, 2013
Issue RFP for General Contractor	November 1, 2013
Award Contract for General Contractor	January 1, 2014
Generators Shipped from Manufacturers	January 15, 2014
Switchgear Shipped from Manufacturers	February 1, 2014

WD1 & WD2 Shutdown (WD3 On stand-by)	March 1, 2014
YEC Employees Complete Isolation of WD1&WD2	March 15, 2014
WD3 Shutdown	April 1, 2014
Start-Up & Commissioning Complete Unit 1	October 1, 2014
Start-Up & Commissioning Complete Unit 2	November 1, 2014

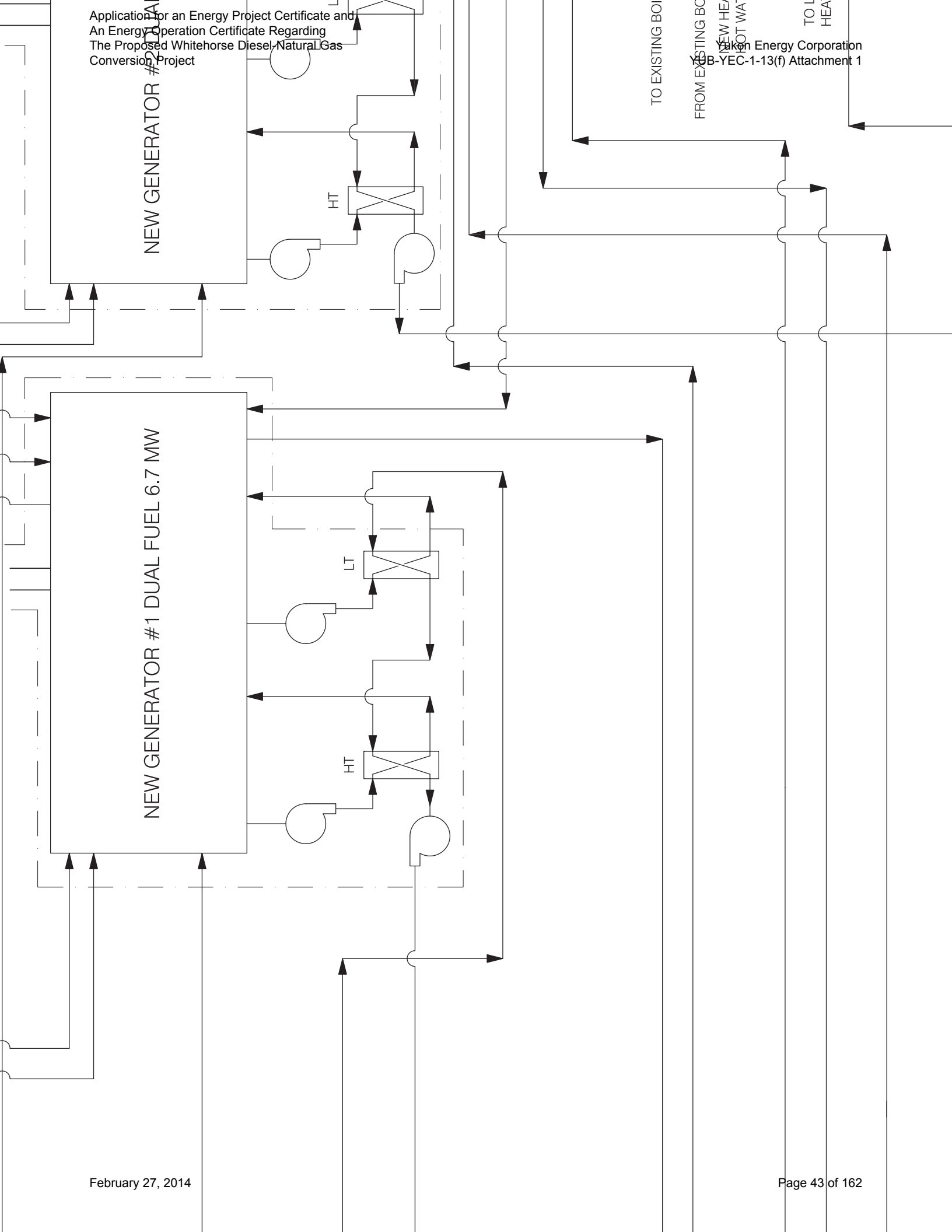
The preliminary schedule for the project can be found in Appendix H.

7. GENERATOR SUPPLIERS

A market analysis was done in the previous study by BBA; the conclusion of this analysis was that there are very few recognized/proven suppliers in the market that can supply the unit YEC would like to install. The criterion that has the most significant influence on limiting the number of suppliers is for duel fuel (natural gas/diesel). At the time when BBA obtained budgetary quotes from potential suppliers (June 2012), only Wärtsilä and MAN had a unit that met the required specifications. Since then MAN retracted their quote as their current duel fuel model is being phased out (due to poor efficiency). Their new (not market tested) model is expected to be released 2015-2016.

Appendix A

Preliminary Process Flow Diagram


NEW GENERATOR #2 DUAL FUEL 6.7 MW
LT
HT
NEW GENERATOR #1 DUAL FUEL 6.7 MW
LT
HT
TO EXISTING BOI
FROM EXISTING BO
NEW HEA
HOT WAT
TO L
HEA

Appendix B

General Arrangement Sketch

NEW GEN #1

NEW GEN #2

EXHAUST

EXHAUST

ACCESSORIES RACK

STARTING AIR COMPRESSOR

STARTING AIR COMPRESSOR

DIESEL DAY TANK, PUMP AND FILTER

SILENCER

AIR TANK

AIR TANK

AIR TANK

AIR TANK

AIR TANK

GAS TRAIN

HEAT EXCH.HR

HEAT EXCH.HT

HEAT EXCH.LT

NEW RADIATOR

FUTURE EXHAUST

INSTRUMENT AIR COMPRESSORS

MIRRLEES

RTU

1HP PUMP

COMPRESSOR #1

COMPRESSOR #2

COMPRESSED AIR TANKS

12.5HP PUMP LUBE OIL?

600V MCC PANELS

No. 3 CONTROL PANEL

WD3

WD4

WD5

ALT. TERM BOX

ENGINE CONTROL CABINET

ALT. TERM BOX

ENGINE CONTROL CABINET

P126-52-WD4

SYNCRO

Appendix C

Estimate References

1. DATE, CURRENCY AND EXCHANGE RATE

The capital cost estimate is based on prices for Q1 2013 in Canadian Dollars (CAD) unless noted otherwise. The exchange rate used for the project was 1 USD = 1 CAD. No other exchange rates were used.

2. LABOUR RATES AND LABOUR PRODUCTIVITY FACTORS

For the purpose of defining the "work week", all estimated costs for labour are based on ten (10) hours per day, through seven (7) days per week, for a total of seventy (70) hours work weeks. There is no allowance for a second working team (night shift). The present estimate is structured and based on the philosophy that contracts will be awarded to reputable Contractors on a lump-sum basis.

Table 1 presents union wage rates for major construction trades as well as factored construction equipment rates thus resulting in an all-in blended rate for the various trades.

Table 1: Capital Cost Estimate Labour Rates

Crew Type	Labour Rate			Equipment Costs	Total
	Direct	Indirect	Sub-Total		
Site Works - Civil	$73.20	$44.60	$117.80	$67.20	$185.00
Concrete Works	$74.00	$48.00	$122.00	$12.90	$134.90
Metal Works	$79.50	$51.30	$130.80	$38.40	$169.20
Architectural Finishes	$74.20	$48.10	$122.30	$8.20	$130.50
Mechanical - Process	$78.00	$51.30	$129.30	$26.50	$155.80
Mechanical - Building	$74.80	$50.10	$124.90	$23.40	$148.30
Piping	$73.80	$49.80	$123.60	$21.80	$145.40
Piping Insulation	$71.30	$44.30	$115.60	$7.60	$123.20
Electrical	$79.50	$51.80	$131.30	$4.90	$136.20
Automation / Telecom	$78.30	$51.40	$129.70	$1.70	$131.40

In this table, the crew rates are composed of direct and indirect labour rates, plus the required construction equipment per trade to accomplish their tasks. The direct costs are calculated on an assumption of 70 hours per week, considering 40 hours at the regular rate, 20 hours applying an overtime multiplier of 1.5 and the remaining 10 hours applying an overtime multiplier of 2 to the regular rate. These rates include a mix of skilled, semi-skilled and unskilled labours for each trade as well as the fringe benefits on top of gross wages. Direct supervision by the foremen and surveyors is built into the direct costs.

The indirect cost component consists of allowances for small tools, consumables, supervision by the general foreman, management team, Contractors' on-site temporary construction facilities, mobilization/demobilization, Contractors' overhead and profit. Also included are the costs related to the transportation of the employees from their residence to the construction site. Fly-in fly-out (FIFO) costs have been determined based on working a, three (3) weeks on one (1) week off, shift rotation. A sufficient employee allowance of $1,000 per rotation has been included for commuting from the Western or Central provinces, to the site.

The construction equipment rates are based on the rates proposed by "La Direction Générale des Acquisitions du Centre de Services Partagés du Québec", detailed within edition dated April 1, 2012. The cost used for fuel (diesel) in this estimate is 1.20 $/litre, assuming a rebate of certain taxes. In brief, the crew rates are developed for each discipline (by speciality), and established, based on the assumption that all hourly workers are unionized.

Many terms are used to describe productivity in the construction industry; performance factor, production rate, unit person-hour rate and others. Traditionally, productivity has been defined as the ratio of input/output, i.e., the ratio of the input of an associated resource (usually expressed in person-hour) to real output (in creating economic value). Labour productivity in the construction industry is the physical progress achieved per person-hour, e.g., person-hours per linear meter of conduit laid or person-hours per cubic meter of concrete poured. The two (2) most important measures of labour productivity are:

- The effectiveness with which labour is used in the construction process;
- The relative efficiency of labour, doing what is required, at a given time and place.

Table 2 presents the labour productivity factors applied in the capital cost estimate:

Table 2: Productivity Factors Used for the Capital Cost Estimate

Activity	Productivity Factor
Site Works - Civil	1.495
Concrete Works	1.570
Structural Works	1.676
Architectural Finishes	1.601
Mechanical / Equipment	1.714
Piping	1.801
Electrical	1.751
Automation / Telecom.	1.739
Average	1.668

3. MOBILIZATION AND DEMOBILIZATION

The General Contractor will be from outside the Yukon thus the cost of mobilization and demobilization are an important element to consider in the cost estimate. The cost associated with this element has been built into the labour rates used in the estimate.

4. LODGING

As per the preliminary schedule, much of the site work would be done during the spring and early summer. Lodging can sometimes be an concern in the area during the summer months, however, due to the number of external resources required for the job (20-40) this should not be a major issue. Also, it has been identified that certain trades are available locally (i.e., for piping and electrical), where possible the GC will be encouraged to use local labour.

Appendix D

Freight References

Air Freight – Volga Airlines

De : Peter Baldauf [mailto:peter@volga-dnepr.us]
Envoyé : 1 février 2013 15:47
À : peter@volga-dnepr.us; Marcoux, Jocelyn; 'Axel Kaldschmidt'
Cc : 'Sales'
Objet : RE: Transport of generators to Withehorse, Yukon

Jocelyn,

Thank you for your request; we are pleased to offer the following:

Quotation Ref #	**326221**
Aircraft	**AN-124 100**
Route	**YVR – YXY**
Cargo	**Generator**
Payload	**See below**
Date	**First availability is currently February 8th**
Price	**US $ 725,000 NET/NET* initial flight up to 70 tons**
	US $ 270,000 NET/NET* for each consecutive flight YVR - YXY

Exclusions

Supplementary information
* Prices are valid not longer than 30 days
* Prices are based on current (on the date of quotation) fuel prices and are subject to revision due to fuel price fluctuation;
* Prices will absorb +/-5% of the fuel prices fluctuation, otherwise will increase/decrease accordingly

Notes:
Price is subject to Ruslan International standard terms and conditions.
Charter price excludes all cargo handling/terminal charges
Special conditions and/or exclusions may apply relating to: Royalties, non-objection fees, crane and special equipment hire, fuel escalation, carriage of cargo attendants, war risk insurance, U.S. cabotage (domestic) flights and flights carrying dangerous goods. Details of such conditions are available on request.

To support your charter operation, our Engineering & Logistics Centre provide a comprehensive range of ground logistics & services including; Load planning & Engineering consultation, Route surveys, Haulage, Crane hire, Insurance, Packing and Documentation.

To find out more about these services and to receive a written quotation, please contact your charter sales representative or email our logistics division on sales@volga-dnepr.us

I look forward to hearing any feedback you can provide.

Thank you and Best Regards, Peter Baldauf

Volga-Dnepr Unique Air Cargo, Inc
Sales Executive
9400 Grogan's Mill Road
Suite 220
The Woodlands, Texas 77380
Main: 832 585-8611 x-115
Cell: 832 488-4695
Fax: 832 585-8618
E-mail: Peter@volga-dnepr.us

VOLGA-DNEPR AIRLINES

Волга Днепр

From: peter@volga-dnepr.us [mailto:peter@volga-dnepr.us]
Sent: Thursday, January 31, 2013 6:22 PM
To: Marcoux, Jocelyn; Axel Kaldschmidt
Cc: Sales
Subject: Re: Transport of generators to Withehorse, Yukon

Understood, will quote per trip
Sent from my Verizon Wireless BlackBerry

From: "Marcoux, Jocelyn" <Jocelyn.Marcoux@bba.ca>
Date: Thu, 31 Jan 2013 18:34:58 -0500
To: Peter Baldauf<peter@volga-dnepr.us>; 'Axel Kaldschmidt'<axel@volga-dnepr.us>
Cc: 'Sales - VD UAC'<Sales@volga-dnepr.us>
Subject: RE: Transport of generators to Withehorse, Yukon

Hi Peter,

It has to be YXY, that is where they will be installed. Quote me only the motor, or for separate trips for the frames.

We can also send the frame by road, the biggest problem we have is the motors, they cannot go by road because of a bridge limitation.

Regards,

Jocelyn Marcoux

Estimateur Senior, Mécanique & Tuyauterie, Gestion de Projet



BBA inc. 630, boul. René-Lévesque Ouest, bureau 1900, Montréal, Québec H3B 1S6 CANADA
T +1 514.866.2111, poste 5759 **F** +1 514.866.2116
Courriel : jocelyn.marcoux@bba.ca Site Internet : bba.ca

De : Peter Baldauf [mailto:peter@volga-dnepr.us]
Envoyé : 31 janvier 2013 18:06
À : Marcoux, Jocelyn; 'Axel Kaldschmidt'
Cc : 'Sales - VD UAC'
Objet : RE: Transport of generators to Withehorse, Yukon

Jocelyn,

The MAX payload we can bring into YXY is 80 tons. Is YEG (Edmonton) an option? We can bring up to 109tons in there.

Thank you and Best Regards, Peter Baldauf

Volga-Dnepr Unique Air Cargo, Inc
Sales Executive
9400 Grogan's Mill Road
Suite 220
The Woodlands, Texas 77380
Main: 832 585-8611 x-115
Cell: 832 488-4695
Fax: 832 585-8618
E-mail: Peter@volga-dnepr.us



From: Marcoux, Jocelyn [mailto:Jocelyn.Marcoux@bba.ca]
Sent: Thursday, January 31, 2013 4:32 PM
To: Axel Kaldschmidt
Cc: Sales - VD UAC
Subject: RE: Transport of generators to Withehorse, Yukon

Hi Axel,

We can take apart the motor (70 M tons) and shipped separately the frames (49 x 2 = 98 M tons) it would be a total of 3 trips from YVR-YXY. We need a budget price the job will be done 2014.

Regards,

Jocelyn Marcoux
Estimateur Senior, Mécanique & Tuyauterie, Gestion de Projet



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T +1 514.866.2111, poste 5759 **F** +1 514.866.2116
Courriel : jocelyn.marcoux@bba.ca Site Internet : bba.ca

De : Axel Kaldschmidt [mailto:axel@volga-dnepr.us]
Envoyé : 31 janvier 2013 14:58
À : Marcoux, Jocelyn
Cc : Sales - VD UAC
Objet : RE: Transport of generators to Withehorse, Yukon

Jocelyn,

From initial look at your request, there are already some concerns in regard to AN124 operations for this flight.

1) At the current weight of 119 MT for this generator, it will exceed the limitation of the AN124. Is there any way to lighten the generator?
2) According to the information we are initially looking at, Whitehorse is NOT a viable airport for AN124 or any larger aircraft. The runway is not strong/rigid enough to support our aircraft with this much weight. It would be difficult to operate it in empty with no cargo.
3) At this point Edmonton would be the closest suitable airport to operate from.

We will study this more overnight and see if we can offer any additional suggestions or alternatives.

Regards
Axel

Axel Kaldschmidt
Senior Account Executive
Volga-Dnepr Unique Air Cargo
The Woodlands, TX

Tel: 832-585-8611
Fax: 832-585-8618
Cell: 713-498-8785

From: Marcoux, Jocelyn [mailto:Jocelyn.Marcoux@bba.ca]
Sent: Thursday, January 31, 2013 8:23 AM

To: sales@volga-dnepr.us
Cc: kvus@volga-dnepr.us
Subject: TR: Transport of generators to Withehorse, Yukon

Hi,

I need to know if the plane AN-124 can transport two generators (see Drawing), From Vancouver, BC, Canada and land in Whitehorse, Yukon, CANADA.

How much would it cost to take the generators from Vancouver and ship it to Whitehorse, Canada ?

How long of runway is needed to accept the AN-124 with this cargo ?

More info on the cargo; If you look at the drawing section you will find the **transport measurements**;

top left section (front view), the last measurement (**Bottom**) gives you the transport width = 3 345 mm

bottom section (side view), the last measurement (**Bottom**) gives you the transport length = 11 187 mm

bottom section (side view), the measurement (**right on top of motor**) gives you the transport height (without wastegate) = 4 074 mm

the top right hand side, the Dry (Shipping) Weight is 119 308 kg (119.3 ton)

This drawing comes from our supplier Wartsila in Finland.

Our client is in need of a response from us, to find a solution of shipping the generators, by the end of this week.

Best regards

Jocelyn Marcoux
Estimateur Senior, Mécanique & Tuyauterie, Gestion de Projet

BBA

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T +1 514.866.2111, poste 5759 **F** +1 514.866.2116
Courriel : jocelyn.marcoux@bba.ca Site Internet : bba.ca

Air Freight – Polet Airlines

De: Polet Airlines USA <Sales.USA@PoletAirlines.com>
Envoyé: 31 janvier 2013 14:14
À: Marcoux, Jocelyn
Objet: Re: Transport of generators to Withehorse, Yukon

Jocelyn,

The indication price YVR-YXY is $500,000USD, net. That will exclude crane hire cost at both airports.

Sincerely,

Dmitry Avdeev, MBA
Sales Manager
Polet Airlines
Tel. +1(212)279-3707
Fax: +1(212)279-6499
Email: Sales.USA@PoletAirlines.com
Personal: DAvdeev@PoletAirlines.com
http://www.PoletAirlines.com

On 1/31/13 2:06 PM, Marcoux, Jocelyn wrote:
> Hi Dmitry,
>
> We are doing a study and we need a budget price
> (in today's money), the generator's motors will be shipped march 2014.
> From Vancouver, BC to Whitehorse, Yukon, Canada.
>
> Regards,
>
> *Jocelyn Marcoux***
>
> *Estimateur Senior, Mécanique & Tuyauterie, Gestion de Projet*
>
> *cid:image002.jpg@01CDA7C1.BF4EED80* <http://www.bba.ca/accueil-bba-fr.htm>*
> *
> *BBA inc.* 630, boul. René-Lévesque Ouest, bureau 1900, Montréal,
> Québec H3B 1S6 CANADA
> *T*+1 514.866.2111, poste 5759 *F*+1 514.866.2116
> Courriel :jocelyn.marcoux@bba.ca <mailto:jocelyn.marcoux@bba.ca>Site
> Internet : bba.ca <http://www.bba.ca/>
>
> *De :*Polet Airlines USA [mailto:Sales.USA@PoletAirlines.com]
> *Envoyé :* 31 janvier 2013 11:30
> *À :* Marcoux, Jocelyn
> *Objet :* Re: Transport of generators to Withehorse, Yukon
>
> Yes, we probably can. Please send me all details as well as
> dates/deadlines for the move.
>
> Sincerely,

>
> Dmitry Avdeev, MBA
> Sales Manager
> Polet Airlines
> Tel. +1(212)279-3707
> Fax: +1(212)279-6499
> Email: Sales.USA@PoletAirlines.com <mailto:Sales.USA@PoletAirlines.com>
> Personal: DAvdeev@PoletAirlines.com <mailto:DAvdeev@PoletAirlines.com>
> http://www.PoletAirlines.com
>
> On 1/31/13 11:26 AM, Marcoux, Jocelyn wrote:
> > Hi Dmitry,
> >
> > Can you take Only the motor at 70 Ton ?
> >
> > Regards,
> >
> > *Jocelyn Marcoux***
> >
> > *Estimateur Senior, Mécanique & Tuyauterie, Gestion de Projet*
> >
> > *cid:image002.jpg@01CDA7C1.BF4EED80*
> <http://www.bba.ca/accueil-bba-fr.htm>*
> > *
> > *BBA inc.* 630, boul. René-Lévesque Ouest, bureau 1900, Montréal,
> > Québec H3B 1S6 CANADA
> > *T*+1 514.866.2111, poste 5759 *F*+1 514.866.2116
> > Courriel :jocelyn.marcoux@bba.ca <mailto:jocelyn.marcoux@bba.ca>Site
> > Internet : bba.ca <http://www.bba.ca/>
> >
> > *De :*Polet Airlines USA [mailto:Sales.USA@PoletAirlines.com]
> > *Envoyé :* 31 janvier 2013 10:24
> > *À :* Marcoux, Jocelyn
> > *Objet :* Re: Transport of generators to Withehorse, Yukon
> >
> > Jocelyn,
> >
> > Thanks for your request. This is too heavy for AN-124-100. We can take
> > the heaviest piece of 100-105 tons max.
> >
> > Sincerely,
> >
> > Dmitry Avdeev, MBA
> > Sales Manager
> > Polet Airlines
> > Tel. +1(212)279-3707
> > Fax: +1(212)279-6499
> > Email: Sales.USA@PoletAirlines.com
> <mailto:Sales.USA@PoletAirlines.com> <mailto:Sales.USA@PoletAirlines.com>
> > Personal: DAvdeev@PoletAirlines.com
> <mailto:DAvdeev@PoletAirlines.com> <mailto:DAvdeev@PoletAirlines.com>
> > http://www.PoletAirlines.com
> >
> > On 1/31/13 9:05 AM, Marcoux, Jocelyn wrote:

> > > Hi,
> > >
> > > I need to know if the plane AN-124 can transport two
> > > generators (see Drawing), From Vancouver, BC, Canada and land in
> > > Whitehorse, Yukon, CANADA.
> > >
> > > How much would it cost to take the generators
> > > from Vancouver and ship it to Whitehorse, Canada ?
> > >
> > > How long of runway is needed to accept the
> > > AN-124 with this cargo ?
> > >
> > > More info on the cargo; If you look at the drawing
> > > section you will find the *_transport measurements_*;
> > >
> > > top left section (front view), the last measurement
> > > (*_Bottom_*) gives you the transport width = 3 345 mm
> > >
> > > bottom section (side view), the last measurement
> > > (*_Bottom_*) gives you the transport length = 11 187 mm
> > >
> > > bottom section (side view), the measurement
> (*_right on
> > > top of motor_*) gives you the transport height (without wastegate) = 4
> > > 074 mm
> > >
> > > the top right hand side, the Dry (Shipping) Weight is
> > > 119 308 kg (119.3 ton)
> > >
> > > This drawing comes from our supplier Wartsila in
> > Finland.
> > >
> > > Our client is in need of a response from us, to find a
> > > solution of shipping the generators, by the end of this week.
> > >
> > > Best regards
> > >
> > > *Jocelyn Marcoux***
> > >
> > > *Estimateur Senior, Mécanique & Tuyauterie, Gestion de Projet*
> > >
> > > *cid:image002.jpg@01CDA7C1.BF4EED80*
> > <http://www.bba.ca/accueil-bba-fr.htm>*
> > > *
> > > *BBA inc.* 630, boul. René-Lévesque Ouest, bureau 1900, Montréal,
> > > Québec H3B 1S6 CANADA
> > > *T*+1 514.866.2111, poste 5759 *F*+1 514.866.2116
> > > Courriel :jocelyn.marcoux@bba.ca <mailto:jocelyn.marcoux@bba.ca>Site
> > > Internet : bba.ca <http://www.bba.ca/>
> > >

Barge Freight – West Coast Tug & Barge

West Coast Tug & Barge Ltd
PO Box 10
Suite 3 - 730 13th Avenue
Campbell River, BC
Canada, V9W 4Z9

Tel 250.286.1234
e-**Fax** 888.492.7301
info@westcoasttug.ca
www.westcoasttug.ca

SERVICE QUOTATION

QUOTE REFERENCE #:	BBA - 040213 - 01	DATE REFERENCE:	February 4, 2013

To: Gaetan Dagenais
BBA Inc.
514-866-2111
gaetan.dagenais@bba.ca

PURCHASE ORDER #:	

QUOTE ACCEPTED BY:
SIGNATURE
DATE

	DESCRIPTION OF SERVICE		COSTS
Please Initial	CONTAINER FREIGHT TRANSPORT: To charter a tug and barge to transport 10 containers from Vancouver, BC to Skagway, AK, and then return the containers back to Vancouver, BC. This is quoted a charter service and includes 1 day standby for loading and 1 day standby for unloading. Additional time for standby/loading/unloading will be track by the skipper onboard the vessel, and billed as per the terms described below.	$	166,714.29
Please Initial	STANDBY/LOADING/UNLOADING TIME: Additional time involved, outside the regular scope of work described above, will be billed on an hourly basis based on a 24 hour operation to a maximum of $7,000.00 per day.	$	300.00 per hour

Sub Total	**$**	**166,714.29**
HST # 898832530	**$**	-
Quotation total	**$**	-

Terms: This quotation is for the transportation services outlined only, it does not include any terminal fees, fuel surcharge, assist boats, Port fees, or any Custom fees unless specially outlined. Our terms and conditions are listed on the reverse side of our Bill of Lading. A copy will be supplied on confirmation of quote. Payment terms are COD unless credit terms are granted prior to the commencement of the job. Once credit has been approved the terms are net 30 days 2% per month (26.8% per annum). This quotation is valid for 10 days unless otherwise specified. Once we receive acceptance by way of a faxed signed and dated copy we will require 14 days to schedule and confirm arrangements.

"PROPLELLING BUSINESSES FORWARD SINCE 1976"

Hi Jocelyn,

The barge is 200' x 54' and has a capacity of 2,200 MT. I have quoted this job as a charter service so you may utilize the entire capacity of the barge. The only potential difference in cost would come from addition standby/loading/unloading time, and that would be charged as per the terms described in the service quotation. Just an fyi…we do have a 230' x 60' barge as well with a capacity of 3,800 MT. If you require additional capacity, I could provide a quote for that barge as well?! Let me know!

Thanks,
Graeme

From: Marcoux, Jocelyn [mailto:Jocelyn.Marcoux@bba.ca]
Sent: February-05-13 4:13 AM
To: Graeme McNeill
Cc: Dagenais, Gaétan
Subject: RE: need a location price

Hi,

Tanks for the quotation. What is the capacity of the barge ? Can we put more than 10 containers on board ? Any Extra costs ?

Regards,

Jocelyn Marcoux
Estimateur Senior, Mécanique & Tuyauterie, Gestion de Projet

BBA inc. 630, boul. René-Lévesque Ouest, bureau 1900, Montréal, Québec H3B 1S6 CANADA
T +1 514.866.2111, poste 5759 **F** +1 514.866.2116
Courriel : jocelyn.marcoux@bba.ca Site Internet : bba.ca

De : Graeme McNeill [mailto:Graeme.McNeill@westcoasttug.ca]
Envoyé : 4 février 2013 17:18
À : Dagenais, Gaétan
Cc : Marcoux, Jocelyn
Objet : RE: need a location price

Hi There,

Attached is a service quotation to transport a barge load of containers between Vancouver, BC and Skagway, AK, and then return to Vancouver, BC. This is quoted on a charter basis and included 1 day standby time for loading and 1 day standby time for unloading. If you have any questions or concerns, please don't hesitate to contact me directly. Thanks for the opportunity to quote your work, I look forward to your response.

Kind Regards,

GRAEME MCNEILL, B.Comm
Sales Representative
PO Box 10, Suite 3 - 730 13th Avenue
Campbell River, BC, V9W 4Z9
Tel: 250.287.4433 Ext 205 Cell: 250.203.9282 e-Fax: 888.492.7301
Email: Graeme.McNeill@westcoasttug.ca
Website: www.westcoasttug.ca

"PROPELLING BUSINESSES FORWARD SINCE 1976."

Please consider the environment before printing.

From: Dagenais, Gaétan [mailto:Gaetan.Dagenais@bba.ca]
Sent: February-04-13 1:55 PM
To: info@westcoasttug.ca
Subject: TR: need a location price

Hi

I just want to know if you are available to give some rate for a barge

I am waiting for your answer, I have to close my project next day

Best regards

Note can you send your answer also to

Jocelyn.Marcoux@bba.ca

Gaetan Dagenais
Estimateur sénior.

BBA inc. 630, boul. René-Lévesque Ouest, bureau 1900, Montréal, Québec H3B 1S6 CANADA
T +1 514.866.2111, poste **5994** **F** +1 514.866.2116
Courriel : gaetan.dagenais@bba.ca Site Internet : bba.ca

De : Dagenais, Gaétan
Envoyé : 1 février 2013 08:58
À : 'info@westcoasttug.ca'
Objet : need a location price

Hi

I just want to know how much it cost for a location of a barge, We need a budget price and the project will be done in summer 2014 but the price should be in dollar today

We suppose to received our equipment in container (10) in Vancouver an than we have to go to Skagway

Then we have to take some material in container in Skagway and come to Vancouver

Thanks

I waited for your answer

Gaetan Dagenais
Estimateur sénior.

BBA inc. 630, boul. René-Lévesque Ouest, bureau 1900, Montréal, Québec H3B 1S6 CANADA
T +1 514.866.2111, poste **5994** **F** +1 514.866.2116
Courriel : gaetan.dagenais@bba.ca Site Internet : bba.ca

AVIS
Ce courriel et toute information qui y est jointe sont confidentiels et peuvent être assujettis au secret professionnel. Si vous l'avez reçu par inadvertance, détruisez-le et communiquez avec nous.

NOTICE
This e-mail and any information enclosed are confidential and may be subject to professional secrecy. If you received this e-mail by mistake, please destroy it and contact us.



Whitehorse Diesel Generating Plant
Conversion and Upgrades

Stage 1 – WD1 and WD2 Replacement
Final Report and Cost Estimate



Rail Freight – White Pass

De : Ed Hanousek [mailto:EHanousek@wpyr.com]
Envoyé : 4 février 2013 16:31
À : Marcoux, Jocelyn
Cc : Mark Schaefer; Allison Haas
Objet : RE: Transport of generators to Whitehorse

Jocelyn;
Thank you for your inquiry, White Pass is currently not set up for hauling freight, we do not have the rail cars or other equipment needed in order to handle freight on the railroad, our current business is hauling passengers.
The best method for hauling freight from tide water in Skagway to the Yukon is via truck and trailer on the Klondike Highway.

E.C.Hanousek
Superintendent Rail Operations

From: Marcoux, Jocelyn [mailto:Jocelyn.Marcoux@bba.ca]
Sent: Tuesday, January 29, 2013 2:13 PM
To: Ed Hanousek
Cc: Mark Schaefer; Allison Haas
Subject: Transport of generators to Whitehorse

Hi,

We are doing a study for our client, Yukon Energy, to replace two existing generators at their plant in Whitehorse.

In our study the logistic of getting the machines to Whitehorse is a big concern and the question we have is; can those be shipped from Skagway via WPYR rail system ? Is any of these weight and sized equipment can be shipped via your rail system ? Can regular 20 Foot container be shipped via train ? And what would be the cost ? we have the manpower and equipment for loading/unloading. We also have to take the old one back to Skagway.

I have attached a drawing, but they have total shipping dimension in one piece = 3 345 mm width x 4 074 mm high x 11 187 mm long for 119.3 Ton.

If this is too big, they can be taken apart and shipped separately, the motor = 2 640 mm width x 3 800 mm high x 7 500 mm long for 70 Ton.

Anything will help. Best Regards,

Road Freight - Mommoet

De: Marcoux, Jocelyn
Envoyé: 5 février 2013 17:42
À: 'Willie Gavinchuk'
Cc: 'Gilles Emond'; 'John Tomas'
Objet: RE: Prix de transport

Importance: Haute

Hi Willie,

When we talked last week following my e-mail below, I understood you would send me a "**budget Proposal**" for the transport of my generators to Whitehorse.

Can you just confirm by e-mail what would be your **budget price** for the following options;

Option 1; from the port of Skagway to Whitehorse (inside the generator Bldg.).
Transport of 2 motors (70Tons/Ea.) from Skagway to Whitehorse (172 Km) = _____$
Transport of 2 Frames (49Tons/Ea.) from Skagway to Whitehorse (172 Km) = _____$
Transport of 8 pieces of old generators from Whitehorse to Skagway (172 Km) = _____$
Transport of 8 pieces of old generators from Port of Vancouver to scrapyard (2 Km) = _____$

Option 2; from the Vancouver to Whitehorse (inside the generator Bldg.).
Transport of 2 motors (70Tons/Ea.) from Port of Vancouver to Vancouver airport (45 Km) = _____$
Transport of 2 motors (70Tons/Ea.) from Whitehorse airport to Yukon Energy, Whitehorse (5 Km) = _____$
Transport of 2 Frames (49Tons/Ea.) from Port of Vancouver to Vancouver airport (45 Km) = _____$
Transport of 2 Frames (49Tons/Ea.) from Whitehorse airport to Yukon Energy, Whitehorse (5 Km) = _____$
Transport of 8 pieces of old generators from Whitehorse to Skagway (172 Km) = _____$
Transport of 8 pieces of old generators from Port of Vancouver to scrapyard (2Km) = _____$

Again, it is a budget price I need and I understand that further investigation will be needed to confirm the feasibility of crossing the bridge in Skagway.

Can I expect a response by tomorrow ?

Best regards,

Jocelyn Marcoux
Estimateur Senior, Mécanique & Tuyauterie, Gestion de Projet

BBA inc. 630, boul. René-Lévesque Ouest, bureau 1900, Montréal, Québec H3B 1S6 CANADA
T +1 514.866.2111, poste 5759 **F** +1 514.866.2116
Courriel : jocelyn.marcoux@bba.ca Site Internet : bba.ca

De : Marcoux, Jocelyn
Envoyé : 31 janvier 2013 14:41
À : 'Willie Gavinchuk'
Cc : Gilles Emond; John Tomas
Objet : RE: Prix de transport

Hi Willie,

I am still waiting for your options, but I have been working on others. Seems like the motors and frames separately, could be flown from Vancouver to Whitehorse.

I will still need your price to take them from the port of Vancouver to the airport, glide them in the plane, from Whitehorse's Airport to the site. 3 plane trip will be done, 1 with the frames and 1 for each of the motors.

Figure also to take the old Mirlees in parts (4 each) to Vancouver via Skagway, they will be cut in parts by somebody else.

Best Regards,

Jocelyn Marcoux
Estimateur Senior, Mécanique & Tuyauterie, Gestion de Projet

BBA

BBA inc. 630, boul. René-Lévesque Ouest, bureau 1900, Montréal, Québec H3B 1S6 CANADA
T +1 514.866.2111, poste 5759 **F** +1 514.866.2116
Courriel : jocelyn.marcoux@bba.ca Site Internet : bba.ca

De : Willie Gavinchuk [mailto:Willie.Gavinchuk@mammoet.com]
Envoyé : 28 janvier 2013 17:30
À : Marcoux, Jocelyn
Cc : Gilles Emond; John Tomas
Objet : Re: Prix de transport

Jocelyn

MAMMOET uses rubber tired equipment not tracks. To transport just the engine at 70te, the transport equipment would add additional 55te for a gross weight of 125te, far in excess of the limits stated.

If the engine was removed from the skid and shipped in a rigid transport frame with jacking provisions, crossing the bridge may be feasible if the bridge can be closed for 3 days to allow the crossing on a slide track.

Regards
Willie Gavinchuk
1-780-449-0552 ext 8565
1-780-914-1815 cell

On 2013-01-28, at 15:02, "Marcoux, Jocelyn" <Jocelyn.Marcoux@bba.ca> wrote:

Hi all,

We asked the railway owners and nothing goes or went thrue the train the tunel and narrow track doesn't allow it. But the limitations also state below and attached in yellow …. Are we or can we say that we are within these limits ??

WEIGHT LIMITATION 290
The weight limit of the Skagway Transfer Bridge and Barge Facility Dock is 80 tons, gross. Track pressure for tracked equipment shall not exceed 1,500 pounds per square foot. No single unit of cargo or trailered combination of cargo is permitted to use the facility if it exceeds these weight limits.

Best regards,

Jocelyn Marcoux
Estimateur Senior, Mécanique & Tuyauterie, Gestion de Projet
<image001.jpg>

BBA inc. 630, boul. René-Lévesque Ouest, bureau 1900, Montréal, Québec H3B 1S6 CANADA
T +1 514.866.2111, poste 5759 **F** +1 514.866.2116
Courriel : jocelyn.marcoux@bba.ca Site Internet : bba.ca

De : Willie Gavinchuk [mailto:Willie.Gavinchuk@mammoet.com]
Envoyé : 28 janvier 2013 16:54
À : Gilles Emond; Marcoux, Jocelyn
Cc : John Tomas
Objet : FW: Prix de transport

Based on the limits of the bridge (80te) and the weight of the engine (70te), disassembly will be required.

The historical Whitepass and Yukon railway may have been used to deliver the original in parts many years ago.

Willie Gavinchuk
780-485-8565 Direct
780-914-1815 Cell

From: Gilles Emond
Sent: Monday, January 28, 2013 2:48 PM
To: Willie Gavinchuk
Subject: FW: Prix de transport

Here you go Willie…

Regards,

G

From: Marcoux, Jocelyn [mailto:Jocelyn.Marcoux@bba.ca]
Sent: Friday, January 18, 2013 9:19 AM
To: Gilles Emond
Subject: RE: Prix de transport

Mr Emond,

Je vous renvoie le dessins de la nouvelle génératrice, en espérant que vous pourrez l'utiliser. De même je vous envoie deux dessins des anciens modèles existants. Si vous avez des problèmes faite le moi savoir.

Salutations,

Jocelyn Marcoux
Estimateur Senior, Mécanique & Tuyauterie, Gestion de Projet
<image001.jpg>

BBA inc. 630, boul. René-Lévesque Ouest, bureau 1900, Montréal, Québec H3B 1S6 CANADA
T +1 514.866.2111, poste 5759 **F** +1 514.866.2116
Courriel : jocelyn.marcoux@bba.ca Site Internet : bba.ca

De : Gilles Emond [mailto:Gilles.Emond@mammoet.com]
Envoyé : 18 janvier 2013 08:20

À : Marcoux, Jocelyn
Objet : RE: Prix de transport

Bonjour M. Marcoux,

Pouvez-vous nous faire parvenir les dimensions et poids pour les 2 types de génératrices, ils nous est impossible d'ouvrir l'attachement fournie.

Salutations,

Mammoet Canada de l'Est Ltée.
Gilles Emond

Directeur des Projets

12400 boul. Industriel
Montréal, Québec
Canada H1B 5M5

Phone: +1 (514) 645-4333 x4010
Facsimile: +1 (514) 645-5222
Cell phone: +1 (519) 239-8082
E-mail: Gilles.Emond@mammoet.com

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Visit our corporate website at www.mammoet.com

From: Marcoux, Jocelyn [mailto:Jocelyn.Marcoux@bba.ca]
Sent: Tuesday, January 08, 2013 4:48 PM
To: Gilles Emond
Subject: Prix de transport

Bonjour Mr. Emond,

Suite à notre conversation téléphonique je vous fait parvenir les specs. des génératrices et autres documents pertinents pour le transport des unités vers Whitehorse. Comme je vous disais le port de Skagway, Alaska me semblais être une option valable dans la mesure où nous pouvons passer par la route vers Whitehorse ensuite. Prévoir que les génératrices arriveront à Montréal pour être prises en charge et transportées par vous à partir de là, je voudrais une solution complète ou vous les entrez même à l'intérieur du bâtiment chez mon client, n'oubliez pas qu'il faut sortir, charger et ramener au sud les deux génératrices existantes.

Si vous avez d'autres questions appeler moi.

Salutations,

Port of Skagway
Tariff No. 2

RULES, REGULATIONS AND CHARGES FOR MISCELLANEOUS SERVICES

SECTION 1	**ITEM**
WEIGHT LIMITATION	290

The weight limit of the Skagway Transfer Bridge and Barge Facility Dock is 80 tons, gross. Track pressure for tracked equipment shall not exceed 1,500 pounds per square foot. No single unit of cargo or trailered combination of cargo is permitted to use the facility if it exceeds these weight limits.

DEFINITIONS 300

(A) WHARFAGE

Wharfage is the charge assessed against freight passing or conveyed over the city's transfer bridge; it is the charge for use of the transfer bridge and does not include charges for any service.

(B) STORAGE – FREE TIME

Free time is the specified number of days during which cargo may occupy space assigned to it within the staging area without being subject to demurrage or storage charges.

Free time shall not exceed: Inbound – five days
Outbound – seven days

The following days shall not be included in the computation of free time:

(1) Day(s) while vessel is loading and/or discharging cargo.
(2) Days observed as holidays by the city:

New Year's Day..... January 1st
Martin Luther King Day .... 3rd Monday in January
President's Day..... 3rd Monday in February
Seward's Day.....Last Monday in March
Memorial Day.....Last Monday in May
Fourth of July.....July 4th
Labor Day ..... 1st Monday in September
Alaska Day.....October 18th
Veteran's Day .....November 11th
Thanksgiving Day..... 4th Thursday in November
Christmas Day.....December 25th

Appendix E

Generator Supplier References

De: Mark.kennedy@wartsila.com
Envoyé: 25 janvier 2013 11:35
À: Joncas, Denis
Objet: RE: Quote

Hi Denis,

For 2 x 16V34DF equipment supply you are looking at a **budgetary** price in the order of $11M. This is for equipment delivered to a suitable Canadian port.

We can provide a firm offer when we have received the RFP and have a better understanding of the scope of supply required for this project.

Sincerely,

Mark Kennedy
Business Development Manager
Wärtsilä Canada Incorporated

1771 Savage Road
Richmond, BC V6V1R1
Canada

Office +1 604-244-8181
Mobile +1 604-218-1567
mark.kennedy@wartsila.com

De: Mark.kennedy@wartsila.com
Envoyé: 25 janvier 2013 16:59
À: Joncas, Denis
Cc: Gagnon, Christian
Objet: RE: Quote

Hi Denis,

To be honest the equipment items we discussed are not material in cost to change the budgetary quote eg blackstart. Transport is a factor though and we will do more work on this when the RFP comes out. Delivering to Skagway is fine for the budgetary quote provided, however more work will need to be done to accurately understand the road transport costs to site. There are a number of variables on this one.

Hope that is OK.

Sincerely,

Mark Kennedy
Business Development Manager
Wärtsilä Canada Incorporated

1771 Savage Road
Richmond, BC V6V1R1
Canada

Office +1 604-244-8181
Mobile +1 604-218-1567
mark.kennedy@wartsila.com



BUDGETARY PROPOSAL

June 22, 2012

Customer **BBA Engineering**

Attn. Mr. Denis Joncas
Principal Engineer
348 Boul Sir Wilfred-Laurier, Mont-Saint-Hilaire, J3H 3N9
Quebec Canada

Subject: **Offer for BBA Project in Yukon Territory**.

Dear Mr. Joncas,

We are pleased to offer you power generation equipment and services for a stationary power plant according to the scope of supply below.

The prime movers consist of 3 Wärtsilä 16V34DF engines. The total output of the stationary power plant specified at the outgoing feeder terminal is 20,301 kW. These output values are based on the following conditions:

Average ambient temperature	20 °C
Maximum ambient temperature	30 °C
Relative humidity	50 %
Altitude	500 m
Generator voltage	13800 V
Frequency	60 Hz
Power factor	0.80
Service voltage	480 V
Liquid fuel viscosity (pilot fuel)	10 cSt
Liquid fuel lower heating value	41,700 kJ/kg
Gas fuel main gas supply pressure	6.0 bar(a)
Gas fuel lower heating value	36.8 MJ/Nm3
Gas fuel methane number	89
Heat rate (LHV)	See attached sheet

Price

The total price (budgetary) for equipment according to the scope of supply below is $CAD 13,405,000.

This information is confidential and proprietary to Wärtsilä. No distribution or duplication in any form of any material contained herein is permitted without the prior approval of Wärtsilä.



Project name: BBA Budgetary
Project number: TBA
Quotation number: TBA
Document creation date: June 21, 2012

Price conditions

The price does not include customs duty, taxes or any other charges outside the country of origin.

Payment terms

To be determined.

Delivery terms

CIF (Canadian Port of Choice), according to Incoterms 2010.

Delivery time

Delivery time will be conditional to unsold production capacity. The equipment will be ready for shipment from our factory not later than 7 months after the date of signature of the Wärtsilä Supply Contract and receipt of advance payment as defined therein.

General

The following documents shall form an integral part of this offer.

Exhibit A	Scope of supply
Exhibit B	Wärtsilä Standard Supply Contract (available upon request from Wärtsilä)

This offer excludes any other items not specifically described in Exhibit A under Wärtsilä's responsibility, as well as access roads, site leveling, soil improvement (unless included in Exhibit A), disposal of soil and construction materials and debris, and all works and materials due to soil or site contamination.

Warranty period

The warranty period with respect to the Equipment begins at the Delivery and ends twelve (12) months from the date of the performance test certificate or eighteen (18) months from the date of the Delivery, whichever first occurs.

Project name: BBA Budgetary
Project number: TBA
Quotation number: TBA
Document creation date: June 21, 2012

Validity

This offer is valid up to July 30, 2012.

We trust our offer meets with your approval and look forward to further discussion. Should you require further information, please do not hesitate to contact us.

Sincerely,

Mark Kennedy

Mark Kennedy

WÄRTSILÄ CANADA

Power Plants



Project name: BBA Budgetary
Project number: TBA
Quotation number: TBA
Document creation date: June 21, 2012

Section	Description	QTY	Responsibility of Wärtsilä	Responsibility of Owner
Total	TOTAL			
A	POWER GENERATION EQUIPMENT			
A1	GENERATING SET			
A1.1	ENGINE			
	Wärtsilä 16V34DF engine	3	x	
A1.2	GENERATOR			
	Generator: 13,800 Volt; 60 Hz	3	x	
	Flexible coupling	3	x	
A1.3	BASE FRAME FOR ENGINE AND GENERATOR			
	Common base frame for engine and generator	3	x	
	Steel springs (set)	3	x	
	Fastening equipment (set)	3	x	
A1.4	CONNECTIONS			
	Flexible connections between engine and external piping	3	x	
	- Flexible hoses and gaskets (set)	1	x	
	- Cooling water bellows (set)	1	x	
	- Exhaust gas bellows	1	x	
	- Charge air bellows compensator	1	x	
A1.5	ENGINE PLATFORMS			
	Engine maintenance platform prefabricated	3	x	
A2	MECHANICAL AUXILIARY SYSTEMS			
A2.1	AUXILIARY MODULES			
	Engine auxiliary module	3	x	
	- Fuel oil filter	1	x	
	- Fuel feed pump	1	x	
	- Return fuel pump	1	x	
	- Return fuel tank	1	x	
	- Pre heating unit	1	x	
	- Thermostatic valve high temperature water system	1	x	
	- Thermostatic valve low temperature water system	1	x	
	- Pressure increasing pump	1	x	
	- Piping and insulation	1	x	
	- Valves and gauges	1	x	
	- Module control panel	1	x	
	Exhaust gas module	3	x	
	- Low temperature expansion tank	1	x	
	- Charge air silencer	1	x	
	- Exhaust gas branch pipe	1	x	
	- Purge fan unit	1	x	
	- Safety vent piping	1	x	

Project name: BBA Budgetary
Project number: TBA
Quotation number: TBA
Document creation date: June 21, 2012

Section	Description	QTY	Responsibility of Wärtsilä	Responsibility of Owner
	- Piping and insulation	1	x	
	- Oil mist separator	1	x	
	Auxiliary module platform	3	x	
A2.2	FUEL SYSTEM			
A2.2.1	LIGHT FUEL OIL SYSTEM			
	Light fuel oil unloading pump unit	1		x
	Light fuel oil tank with a volume of 2,000 m3	1		x
	Light fuel oil tank equipment	1		x
	Light fuel oil transfer pump unit	1		x
	Light fuel oil feeder unit	1	x	
	Light fuel oil flow meter for total fuel consumption measurement	1	x	
	Piping and valves light fuel oil system inside engine hall	1	x	
	Piping and valves light fuel oil system outside engine hall	1		x
A2.2.6	GAS SYSTEM			
	Main safety shut off valve unit	1	x	
	City gate (Gas filtering, heating, tariff-metering)	1		x
	Main gas flow measuring unit	1	x	
	- Flow meter	1	x	
	- Closing valves	2	x	
	Gas regulating unit	3	x	
	- Regulating valves	1	x	
	- Gas filter	1	x	
	- Shut-off valves	2	x	
	- Ventilation valves	3	x	
	- Manual shut-off valve	1	x	
	- Steel frame	1	x	
	Piping and valves fuel gas system inside engine hall	1	x	
	Piping and valves fuel gas system outside engine hall	1		x
A2.3	LUBRICATING OIL SYSTEM			
	Lubricating oil unloading pump unit: fresh oil	1		x
	Lubricating oil storage tank for fresh oil with a volume of 16 m3	1		x
	Equipment for lubricating oil storage tank: fresh oil	1		x
	Separator cleaning device (mobile), cleaning unit	1	x	
	Separator cleaning device (mobile), connection kit	1	x	
	Separator cleaning device (mobile), cleaning liquid	1	x	
	Lubricating oil service tank with a volume of 13 m3	1		x
	Lubricating oil service tank equipment	1		x
	Lubricating oil transfer pump unit (mobile)	1	x	
	Lubricating oil transfer pump unit (stationary)	1	x	



Project name: BBA Budgetary
Project number: TBA
Quotation number: TBA
Document creation date: June 21, 2012

Section	Description	QTY	Responsibility of Wärtsilä	Responsibility of Owner
	Piping and valves lubricating oil system inside engine hall	1	x	
	Piping and valves lubricating oil system outside engine hall	1		x
A2.4	COMPRESSED AIR SYSTEM			
	Starting air bottle	2	x	
	Starting air compressor unit - double	1	x	
	Instrument air compressor unit	2	x	
	Instrument air bottle	2	x	
	Piping and valves compressed air system (set)	1	x	
A2.5	COOLING SYSTEM			
	Cooling radiator	3	x	
	Cooling radiator ladder and railings	3	x	
	Maintenance water tank unit (fresh water)	1	x	
	Piping and valves maintenance water system (set)	1	x	
	Piping and valves cooling system inside engine hall	1	x	
	Piping and valves cooling system outside engine hall	1		x
A2.6	CHARGE AIR SYSTEM			
	Charge air filter	3	x	
	Weather hood	3	x	
	Ducting charge air system (set)	6	x	
A2.7	EXHAUST SYSTEM			
	Exhaust gas silencer	3	x	
	Bellows for exhaust gas silencer	6	x	
	Ducting exhaust gas system (set)	3	x	
	Bellows for exhaust gas ducting	3	x	
	Safety vent counter flanges including rupture disk (for exhaust gas ducting)	6	x	
	Insulation exhaust gas ducting (set)	3	x	
	Exhaust gas stack pipe	3	x	
A2.8	OILY WATER SYSTEM			
	Oily water transfer pump unit	2	x	
	Sludge transfer pump unit	1	x	
	Piping and valves oily water treatment system (set)	1		x
A2.9	WATER TREATMENT SYSTEM			
	Water booster unit	1		x
	Piping and valves treated water system (set)	1		x
A2.10	FIRE PROTECTION SYSTEM			
A2.10.1	FIRE PROTECTION, COMMON			
	Fire water system container	1		x
	- Diesel engine driven pump unit	1		x



Project name: BBA Budgetary
Project number: TBA
Quotation number: TBA
Document creation date: June 21, 2012

Section	Description	QTY	Responsibility of Wärtsilä	Responsibility of Owner
	- Electric motor driven pump unit	1		x
	- Jockey pump	1		x
	- Control system	1		x
	- Sprinklers (set)	1		x
	- Portable fire extinguisher	1		x
	- Piping (set)	1		x
	Fire water tank	1		x
	Fire water tank equipment	1		x
	Water monitor	1	x	
	Outdoor hydrant	6	x	
	Outdoor hose cabinet	6	x	
	Portable fire extinguisher (dry powder type)	6	x	
	Piping and valves fire water system inside engine hall	1	x	
	Underground piping and valves fire water system outside engine hall	1		x
A2.10.2	FIRE PROTECTION, ENGINE HALL			
	Hydrant valve pairs	6		x
	Standpipe hose cabinet	6		x
	Portable fire extinguisher (dry powder type)	12		x
	Mobile foam unit	2		x
A2.10.4	FIRE PROTECTION, ELECTRICAL BUILDING			
	Portable fire extinguisher (CO2 type)	6		x
	Portable fire extinguisher (CO2 type)	1		x
	Portable fire extinguisher (dry powder type)	1		x
A2.10.8	FIRE PROTECTION, FIRE FIGHTING PUMP HOUSE / CONTAINER			
	Wet pipe sprinkler system	1		x
	Portable fire extinguisher (dry powder type)	1		x
A7	AUTOMATION SYSTEM			
A7.1	OPERATOR'S STATION			
	WOIS workstation	2	x	
	WISE workstation	1	x	
	Uninterrupted power supply (UPS)	1	x	
A7.2	CONTROL PANELS			
	Central common control panel (CFA)	1	x	
	Central generating set control panel (CFC)	3	x	
	Differential protection relay	3	x	
	Auxiliary module panel (BJA)	3	x	
A7.3	MAINTENANCE SYSTEMS			
	Eldoc system	1	x	

Project name: BBA Budgetary
Project number: TBA
Quotation number: TBA
Document creation date: June 21, 2012

Section	Description	QTY	Responsibility of Wärtsilä	Responsibility of Owner
	Mama system	1	x	
A7.5	CABLES AND ACCESSORIES			
	Control and instrumentation cables	1	x	
A8	ELECTRICAL SYSTEMS			
A8.1	MAIN SWITCHGEAR (MV SYSTEM)			
	Main busbar	1		x
	Generator cubicle	3		x
	Neutral point cubicle	3		x
	Outgoing feeder cubicle	3		x
	Station auxiliary transformer feeder cubicle	2		x
	Measuring cubicle	1		x
	Generator cubicle cable (set)	3		x
	Generator neutral point cable (set)	3		x
	Outgoing feeder cubicle cable (set)	3		x
	Cable terminations and cable fittings	1		x
A8.2	STATION SERVICE SYSTEM (LV SYSTEM)			
	Station auxiliary transformer	2	x	
	Black start unit	1	x	
	- Diesel generating set	1	x	
	- Light fuel oil tank	1	x	
	- Radiator	1	x	
	- Exhaust gas ducting and silencer	1	x	
	- Interconnecting pipes, valves and flanges (set)	1	x	
	- Electric panel	1	x	
	- Steel frame	1	x	
	- Container	1	x	
	Low voltage switchboard	1	x	
	Radiator panels	3	x	
	Frequency converter (for cooling radiator)	3	x	
	Frequency converter (for engine hall inlet ventilation, generator side)	3		x
	Frequency converter (for engine hall inlet ventilation, auxiliary side)	3		x
	Frequency converter (for engine hall outlet ventilation)	3		x
	Station auxiliary transformer medium voltage cables (set)	2		x
	Station auxiliary transformer low voltage cables (set)	2		x
	Low voltage cables (set)	1		x
	Cable ladders	3		x
	Cable terminations and cable fittings	1		x
A8.3	DC SYSTEM			
	DC system - 24 VDC (grounded)	2	x	



Project name: BBA Budgetary
Project number: TBA
Quotation number: TBA
Document creation date: June 21, 2012

Section	Description	QTY	Responsibility of Wärtsilä	Responsibility of Owner
	DC system - 110 VDC (floating)	2	x	
A8.4	HIGH VOLTAGE SYSTEM (HV SYSTEM)			
A8.4.3	CONNECTION WITH LOCAL INDUSTRY			
	Local electrical study	1		x
	Local interconnect study	1		x
	Distribution cable	1		x
	Physical connection with local industry	1		x
A8.5	PLANT ELECTRIFICATION AND EARTHING			
	Safety earthing system (above ground)	1		x
	Lighting and building electrification	1		x
	- Electrification engine hall, material	1		x
	- Electrification electrical building, material	1		x
	- Electrification fire fighting pump house, material	1		x
	- Electrification material for guard house	1		x
	- Electrification workshop and warehouse, material	1		x
	- Electrification administration building, material	1		x
	- Electrification material for fuel unloading station	1		x
	- Electrification lubricating oil unloading station, material	1		x
	- Electrification MV / LV house, material	1		x
	Lightning protection system	1		x
	Fire detection system	1		x
	- Fire detection engine hall, material	1		x
	- Fire detection electrical building, material	1		x
	- Fire detection fire fighting pump house, material	1		x
	- Fire detection service building, material	1		x
	- Fire detection guard house, material	1		x
	- Fire detection accommodation building, material	1		x
	- Fire detection workshop and warehouse, material	1		x
	- Fire detection administration building, material	1		x
	- Fire detection MV / LV house, material	1		x
	Gas detection system	1	x	
	- Gas detection engine hall, material	1	x	
A9	TOOLS			
	Engine maintenance tools (set)	1	x	
	Engine hand tools (set)	1	x	
	Tools for turbocharger (set)	1	x	
	Oil quality test equipment	1	x	
B	CIVIL AND STRUCTURAL			
B1	ENGINE HALL			
	Substructures engine hall	1		x



Project name: BBA Budgetary
Project number: TBA
Quotation number: TBA
Document creation date: June 21, 2012

Section	Description	QTY	Responsibility of Wärtsilä	Responsibility of Owner
	- Foundations engine	1		x
	- Foundations engine hall	1		x
	- Concrete slabs and ramps	1		x
	- Plumbing and sanitary installations below 0-level	1		x
	Superstructures engine hall, material	1		x
	- Steel frame	1		x
	- Steel frame charge air / exhaust gas pipe module support	1		x
	- Foundation bolts	1		x
	- External walls	1		x
	- Internal walls	1		x
	- Intermediate floor	1		x
	- Roof	1		x
	- Doors	1		x
	- Windows	1		x
	- Finishing	1		x
	- Plumbing and sanitary installations above 0-level	1		x
	Superstructures engine hall, installation	1		x
	Process ventilation engine and auxiliary hall, material	1		x
	Process ventilation engine and auxiliary hall, installation	1		x
	Cranes engine hall, material	1		x
	Cranes engine hall, installation	1		x
B3	ELECTRICAL / CONTROL BUILDING			
	Substructures electrical / control building	1		x
	- Foundations	1		x
	- Concrete slabs and ramps	1		x
	- Plumbing and sanitary installations below 0-level	1		x
	Superstructures electrical / control building, material	1		x
	- Steel frame	1		x
	- Foundation bolts	1		x
	- External walls	1		x
	- Internal walls	1		x
	- Roof	1		x
	- Doors	1		x
	- Windows	1		x
	- Finishing	1		x
	- Plumbing and sanitary installations above 0-level	1		x
	- Comfort ventilation and air conditioning	1		x
	Superstructures electrical / control building, installation	1		x
B5	OTHER POWER PLANT BUILDINGS			
B5.3	FIRE FIGHTING PUMP HOUSE / CONTAINER			



Project name: BBA Budgetary
Project number: TBA
Quotation number: TBA
Document creation date: June 21, 2012

Section	Description	QTY	Responsibility of Wärtsilä	Responsibility of Owner
	Substructures fire fighting pump house	1		x
	Superstructures fire fighting pump house, material	1		x
	Superstructures fire fighting pump house, installation	1		x
B11	OIL STORAGE AND CONTAINMENT AREAS			
B11.1	DAY TANK CONTAINMENT AREA			
	Substructures day tank containment area	1		x
	- Substructures for fresh lubricating oil storage tank with a volume of 16 m3	1		x
	- Substructures for lubricating oil service tank with a volume of 13 m3	1		x
	Day tank containment area slab and wall	1		x
B11.2	FUEL STORAGE CONTAINMENT AREA			
	Substructures fuel storage containment area	1		x
	- Substructures for light fuel oil storage tank with a volume of 2,000 m3	1		x
	Fuel storage containment area slab and wall	1		x
B11.6	LUBRICATING OIL HANDLING FACILITIES			
	Substructures lubricating oil unloading station	1		x
B12	AUXILIARY STRUCTURES			
B12.2	SUPPORTING STRUCTURES			
	Substructures exhaust gas stack	1		x
	Superstructures exhaust gas stack, material	1		x
	Superstructures exhaust gas stack, installation	1		x
	Substructures exhaust gas pipes	1		x
	Superstructures exhaust gas pipes, material	1		x
	Superstructures exhaust gas pipes, installation	1		x
	Substructures pipe bridge	1		x
	Substructures pipe stair	1		x
	Substructures pipe supports	1		x
	Superstructures charge air filter and ventilation unit platform, material	1		x
	Superstructures charge air filter and ventilation unit platform, installation	1		x
B12.4	OIL / WATER COLLECTING AND SEPARATING STRUCTURES			
	Substructures oily water collection and separating structures	1		x
	Superstructures oily water collection and separating structures, material	1		x
	Superstructures oily water collection and separating structures, installation	1		x
B12.5	WATER TREATMENT STRUCTURES			



Project name: BBA Budgetary
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Quotation number: TBA
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Section	Description	QTY	Responsibility of Wärtsilä	Responsibility of Owner
	Superstructures water treatment structures, material	1		x
	Superstructures water treatment structures, installation	1		x
B13	POWER TRANSMISSION AREAS			
B13.1	AUXILIARY TRANSFORMER AREAS			
	Substructures black start unit (container)	1		x
	Superstructures black start unit (container), material	1		x
	Superstructures black start unit (container), installation	1		x
	Substructures auxiliary transformer	1		x
	Conduits in auxiliary transformer area, material and work	1		x
	Fence auxiliary transformer area, material and work	1		x
B14	SITE WORKS			
B14.1	EXISTING STRUCTURES AND DEMOLITION			
	Demolition of existing structures	1		x
	Removal / relocation of existing cables and pipes	1		x
B14.2	SITE PREPARATION			
	Site clearing	1		x
	Removal of contamination	1		x
	Top soil removal	1		x
	Site levelling (cutting and filling)	1		x
	Site excavation	1		x
	Site blasting	1		x
	Site filling, material and work	1		x
	Soil improvement, material and work	1		x
B14.3	UNDERGROUND NETWORK			
	Gas pipe to plant	1		x
	Water pipe to plant	1		x
	Sewage pipe to plant	1		x
	Drainage system, material and work	1		x
	Underground piping, material and work	1		x
	- Sewage	1		x
	- Oily water sewage	1		x
	- Water	1		x
	- Gas	1		x
	Sewage treatment and pump stations, material	1		x
	Sewage treatment and pump stations, installation	1		x
	Underground conduits, cables and lighting pole foundations, material and work	1		x
	Earthing network, material	1		x
	Earthing network, installation	1		x
B14.4	LANDSCAPING			



Project name: BBA Budgetary
Project number: TBA
Quotation number: TBA
Document creation date: June 21, 2012

Section	Description	QTY	Responsibility of Wärtsilä	Responsibility of Owner
	Landscaping, material and work	1		x
	- Lawns	1		x
B14.5	PAVING AND SURFACING			
	Access road, material and work	1		x
	Roads and parking areas, material and work	1		x
	Gravel areas, material and work	1		x
	Curb stones, material and work	1		x
B14.6	SITE ACCESSORIES			
	Fence, material	1		x
	Fence, installation	1		x
B14.7	SHELTERS AND OTHER STRUCTURES			
	Substructures shelters and other structures	1		x
	Superstructures shelters and other structures, material	1		x
	Superstructures shelters and other structures, installation	1		x
C	SURVEYS, ENGINEERING AND DOCUMENTATION			
C1	SURVEYS AND INVESTIGATIONS			
	Soil investigation (made according to Wärtsilä directives)	1		x
	Topographical site survey	1		x
	Seismic survey	1		x
	Environmental study / modelling	1		x
C2	ENGINEERING			
C2.1	ENGINEERING MANAGEMENT			
	Engineering management of engineering activities supplied by Wärtsilä	1	x	
	- Constructability review / design review for Items and work under the responsibility of Wärtsilä	1	x	
	- Prepare and maintain engineering schedule	1	x	
	Engineering management of engineering activities supplied by Client	1		x
C2.2	PROCESS ENGINEERING			
	Process engineering of items supplied by Wärtsilä	1	x	
	Process engineering of items supplied by Client	1		x
C2.3	MECHANICAL ENGINEERING			
	Mechanical engineering of items supplied by Wärtsilä	1	x	
	Mechanical engineering of items supplied by Client	1		x
C2.4	ELECTRICAL ENGINEERING			
	Electrical engineering of items supplied by Wärtsilä	1	x	
	Electrical engineering of items supplied by Client	1		x
C2.5	CIVIL AND STRUCTURAL ENGINEERING			
	Civil engineering of items supplied by Wärtsilä	1	x	



Project name: BBA Budgetary
Project number: TBA
Quotation number: TBA
Document creation date: June 21, 2012

Section	Description	QTY	Responsibility of Wärtsilä	Responsibility of Owner
	Civil engineering of items supplied by Client	1		x
C3	DOCUMENTATION			
C3.1	CONCEPTUAL DESIGN DOCUMENTS			
	Site layout drawing	1	x	
	Power house plan and section drawings	1	x	
	Colour program	1	x	
	Process main flow diagrams	1	x	
	Main single line diagram	1	x	
C3.2	BASIC DESIGN DOCUMENTS			
	Site layout drawing	1	x	
	Power house plan and section drawings	1	x	
	Process main flow diagrams and device lists (detailed)	1	x	
	Main single line diagram (detailed)	1	x	
	Front layout of main electrical cabinets	1	x	
	Dimensional drawings of major equipment	1	x	
	Generating set drawing	1	x	
	Dimensional drawing of generating set foundation	1	x	
	Off-site inspection and test plan (quality plan)	1	x	
C3.3	DETAILED DESIGN DOCUMENTS			
	As per detailed engineering scope of supply list	1	x	
C3.4	CONSTRUCTION AND COMMISSIONING DOCUMENTS			
	Site quality plan	1	x	
C3.6	COMMERCIAL OPERATION DOCUMENTS			
	Station manuals in English (set)	1	x	
	- As hard copy	1	x	
	- On digital media	3	x	
	- Installed into Wärtsilä Information System (WISE)	1	x	
	Station manuals (set) [Language is Spanish]	1	x	
	- As hard copy	1	x	
	- Information structure [In specified language]	1	x	
	- Operating instructions [In specified language]	1	x	
	- Unit and process descriptions [In specified language]	1	x	
	- Manuals for essential OEM equipment [In specified language]	1	x	
	- Brochures [In English]	1	x	
	- Data sheets [In English]	1	x	
	- Drawings [In English]	1	x	
	- On digital media	3	x	
	- Information structure [In specified language]	1	x	
	- Operating instructions [In specified language]	1	x	
	- Unit and process descriptions [In specified language]	1	x	



Project name: BBA Budgetary
Project number: TBA
Quotation number: TBA
Document creation date: June 21, 2012

Section	Description	QTY	Responsibility of Wärtsilä	Responsibility of Owner
	- Manuals for essential OEM equipment [In specified language]	1	x	
	- Brochures [In English]	1	x	
	- Data sheets [In English]	1	x	
	- Drawings [In English]	1	x	
	- Installed into Wärtsilä Information System (WISE)	1	x	
	- Information structure [In specified language]	1	x	
	- Operating instructions [In specified language]	1	x	
	- Unit and process descriptions [In specified language]	1	x	
	- Manuals for essential OEM equipment [In specified language]	1	x	
	- Brochures [In English]	1	x	
	- Data sheets [In English]	1	x	
	- Drawings [In English]	1	x	
D	TRANSPORTATION TO CANDIAN PORT OF CHOICE			
D1	TRANSPORTATION OF ITEMS SUPPLIED BY Wärtsilä			
D1.1	MATERIAL AND SERVICES FOR LOGISTICS			
	Packing and marking of equipment	1	x	
	Arranging of export license or other export authorisation (if needed)	1	x	
	Notification to buyer of time and place of delivery of equipment	1	x	
D1.2	COLLECTION TRANSPORT			
	Loading of equipment at place of manufacturing	1	x	
	Transportation of equipment from place of manufacturing to place of shipment	1	x	
	Transport insurance from place of manufacturing to place of shipment	1	x	
	Unloading equipment at place of shipment	1	x	
	Warehousing in country of shipment (up to 8 month from notice to proceed)	1	x	
	Containerizing of loose cargo at place of shipment	1	x	
	Pre shipment inspection	1	x	
	Pre shipment inspection assistance	1	x	
	Loading of equipment on Ship at port / place of shipment	1	x	
	Fixing cargo on Ship	1	x	
D1.3	MAIN TRANSPORT			
	Engaging and instructing freight forwarder	1	x	
	Arranging of bill of lading	1	x	
	Preparation of origin country documents required for destination customs clearance	1	x	
	Transportation of equipment from port / place of shipment to port / place of destination	1	x	



Project name: BBA Budgetary
Project number: TBA
Quotation number: TBA
Document creation date: June 21, 2012

Section	Description	QTY	Responsibility of Wärtsilä	Responsibility of Owner
	Main transport / freight insurance	1	x	
	Unloading of equipment at port / place of destination	1	x	
	Transportation of equipment from port of entry to warehouse	1		x
	Unloading of equipment at warehouse	1		x
	Warehousing in country of destination	1		x
	Arrange import license or import permit (if required)	1		x
	Import taxes and duties (if required)	1		x
D1.4	SITE TRANSPORT			
	Transport route preparation (if required)	1		x
	- Bridge reinforcements	1		x
	- Pavements for existing roads	1		x
	- Removal of obstacles	1		x
	Loading of equipment on truck at warehouse	1		x
	Transportation of equipment from warehouse to project site	1		x
	Transport insurance from warehouse to project site	1		x
	Unloading of equipment at final destination	1		x
	Destination inspection (if required)	1		x
	Destination inspection assistance	1		x
E	TAXES / DUTIES / PERMITS / INSURANCE			
E1	TAXES / DUTIES			
	Sales / VAT tax and local taxes	1		x
	Construction labour tax	1		x
	Other taxes / duties (if required)	1		x
E2	PERMITS			
	Local business permit	1		x
	Construction permitting, approvals, stamps, etcetera	1		x
	Building permit	1		x
	Water permit	1		x
	Environmental permit	1		x
	Permitting procedures	1		x
	Local fees for doing construction	1		x
	Other permits (if required)	1		x
E3	INSURANCE			
	General commercial liability insurance	1		x
	Workers compensation and employers liability insurance	1		x
	Property and liability coverage	1		x
	Other insurances (if required)	1		x
F	PROJECT MANAGEMENT			
F1	PROJECT MANAGEMENT AT WÄRTSILÄ			

Project name: BBA Budgetary
Project number: TBA
Quotation number: TBA
Document creation date: June 21, 2012

Section	Description	QTY	Responsibility of Wärtsilä	Responsibility of Owner
	Project management [Items and work under the responsibility of Wärtsilä]	1	x	
	Maintain project schedule [Items and work under the responsibility of Wärtsilä]	1	x	
G	CONSTRUCTION MANAGEMENT			
G2	TECHNICAL ASSISTANCE DURING INSTALLATION			
	Mechanical advisor 1	1	x	
	Mechanical advisor 2	1	x	
	Electrical advisor 1	1	x	
	Electrical advisor 2	1	x	
	Civil advisor 1	1	x	
	Civil advisor 2	1	x	
H	TEMPORARY INSTALLATIONS AND ARRANGEMENTS			
H1	ROADS AND WORKING AREAS			
	Temporary access road to site	1		x
	Temporary roads at site	1		x
	Preparation for engine intake	1		x
	Preparing of working areas	1		x
	Lay down area [provide]	1		x
	Lay down area [preparation]	1		x
H2	SITE OFFICE AND STAFF ARRANGEMENTS			
	Site office for Wärtsilä personnel including air conditioning, heating and social facilities	1		x
	Site office for Client	1		x
	Furniture for Wärtsilä site office	1		x
	Computers, phones and other office furnishings for Wärtsilä site office	1		x
H3	UTILITIES			
	Telephone, telefax and internet connection to site	1		x
	Electricity source and hook up, main electrical panel	1		x
	Electricity consumption during construction	1		x
	Water source and hook up	1		x
	Water consumption during construction	1		x
H4	WASTE MANAGEMENT DURING CONSTRUCTION			
	Dust control	1		x
	Sewage collection and treatment	1		x
	Waste disposal Wärtsilä generated	1		x
	Hazardous waste disposal Wärtsilä generated	1		x
H5	SECURITY			
	Temporary fencing	1		x
	General security and site access control	1		x



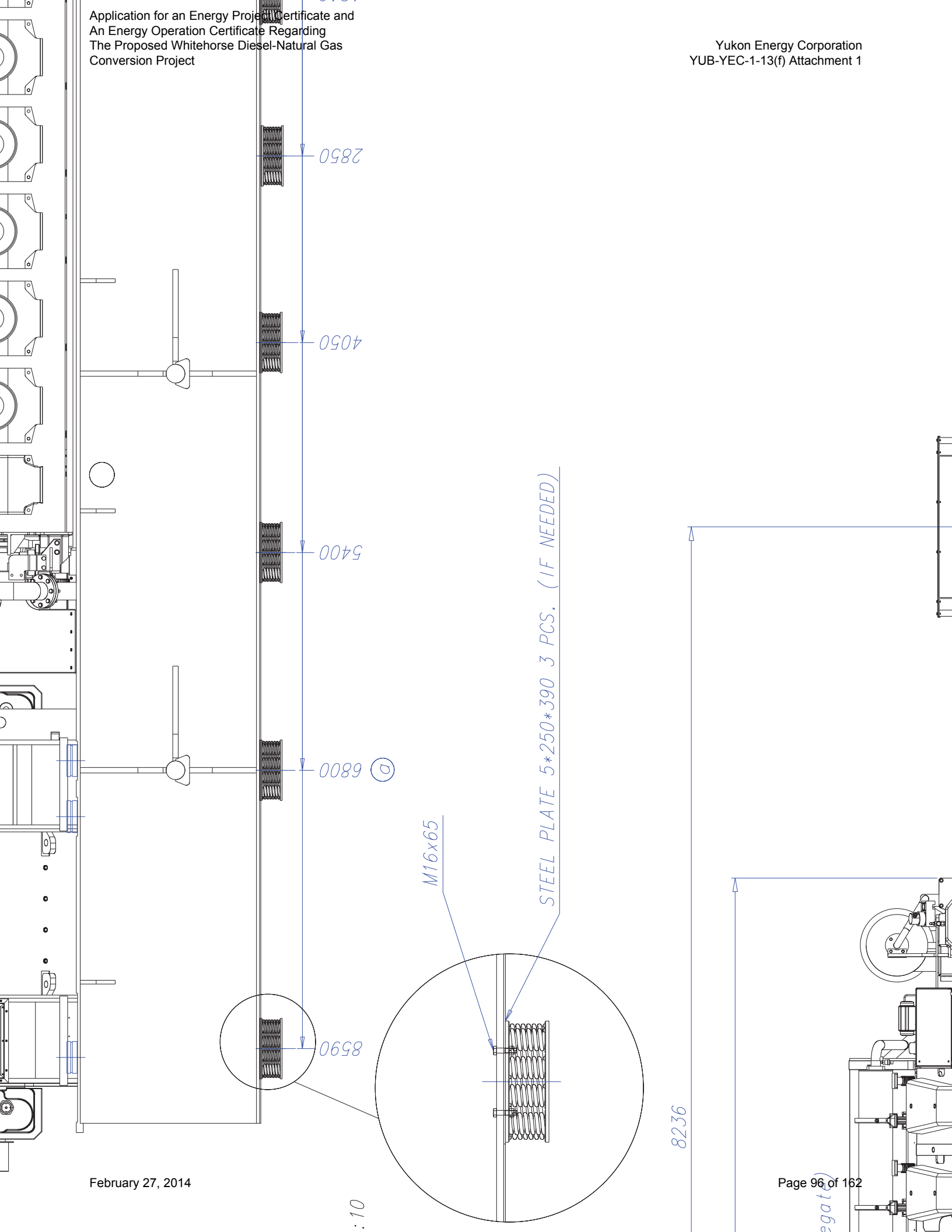
Project name: BBA Budgetary
Project number: TBA
Quotation number: TBA
Document creation date: June 21, 2012

Section	Description	QTY	Responsibility of Wärtsilä	Responsibility of Owner
	Security of Wärtsilä supplied equipment	1		x
H6	SAFETY			
	General safety and fire protection	1		x
	Safety for Wärtsilä personnel and Wärtsilä contractors	1		x
H7	DEMOBILIZATION			
	Restoring of areas used by Wärtsilä	1		x
I	INSTALLATION			
I1	MECHANICAL INSTALLATION			
I1.1	MECHANICAL INSTALLATION OF ITEMS SUPPLIED BY Wärtsilä			
	Process tanks	1		x
	Fuel and water storage tanks	1		x
	Piping and ducting	1		x
	Engine generating sets, units and mechanical systems	1		x
I1.3	MECHANICAL INSTALLATION OF ITEMS SUPPLIED BY Client			
	Process tanks	1		x
	Fuel and water storage tanks	1		x
	Piping and ducting	1		x
	Engine generating sets, units and mechanical systems	1		x
I2	ELECTRICAL INSTALLATION			
	Installation of control and low voltage cables	1		x
	Installation of control, DC and auxiliary panels	1		x
	Installation of low voltage switchgears	1		x
	Installation of medium voltage cubicles	1		x
	Installation of medium voltage cables	1		x
	Installation of station auxiliary transformers	1		x
	Installation of transmission line	1		x
	Installation of cable raceways	1		x
	Installation of safety earthing system	1		x
	Installation of lighting and building electrification	1		x
	Installation of lightning protection system	1		x
	Installation of fire detection system	1		x
	Installation of gas detection system	1		x
J	COMMISSIONING AND START-UP			
J1	INITIAL FILLINGS			
	Initial fillings of fuel oil	1		x
	Initial fillings of lubricating oil	1		x
	Initial fillings fresh engine water	1		x
J2	TECHNICAL ASSISTANCE DURING TESTING AND			



Project name: BBA Budgetary
Project number: TBA
Quotation number: TBA
Document creation date: June 21, 2012

Section	Description	QTY	Responsibility of Wärtsilä	Responsibility of Owner
	COMMISSIONING			
	Commissioning manager (man days)	30	x	
	Mechanical advisor (man days)	40	x	
	Operational advisor (man days)	5	x	
	Electrical advisor (man days)	30	x	
	PLC programmer (man days)	30	x	
	Engine automation and instrumentation tuning (man days)	30	x	
J3	TESTING PROCEDURES			
J3.1	WORKSHOP TESTS			
	Engine test according to standard program	3	x	
	Third party inspectors (if required)	1		x
J3.2	CUSTOMER WITNESS WORKSHOP TEST			
	Allowance (number of persons)	1		x
	Travel (number of persons)	1		x
	Board and lodging (number of days)	7		x
	Local transportation (number of days)	7		x
J3.3	TESTS AND COMPLETION AT SITE			
	Fuel during start-up and commissioning	1		x
	Lubricating oil during start-up and commissioning	1		x
	Fresh engine water during start-up and commissioning	1		x
J4	TRAINING			
J4.1	TRAINING AT WÄRTSILÄ FACILITY			
	Advanced engine training course	1	x	
	Power plant introduction course	1	x	
	Power plant electrification course	1	x	
	Trainees travel to training facility for training course(s) provided by Wärtsilä Finland (number of trips)	12		x
	Board and lodging trainees during training course(s) provided by Wärtsilä Finland (number of days)	60		x
	Local transportation trainees during training course(s) provided by Wärtsilä Finland (number of days)	60		x
	Allowance trainees during training course(s) provided by Wärtsilä Finland (number of days)	60		x
J4.2	TRAINING AT SITE			
	Operation and maintenance training (number of days)	10	x	
	Electrical training (number of days)	5	x	
	Travel (number of persons)	2	x	
	Board and lodging training instructor (number of days)	21	x	
	Local transportation training instructor (number of days)	21	x	
	Training material (per person)	5	x	

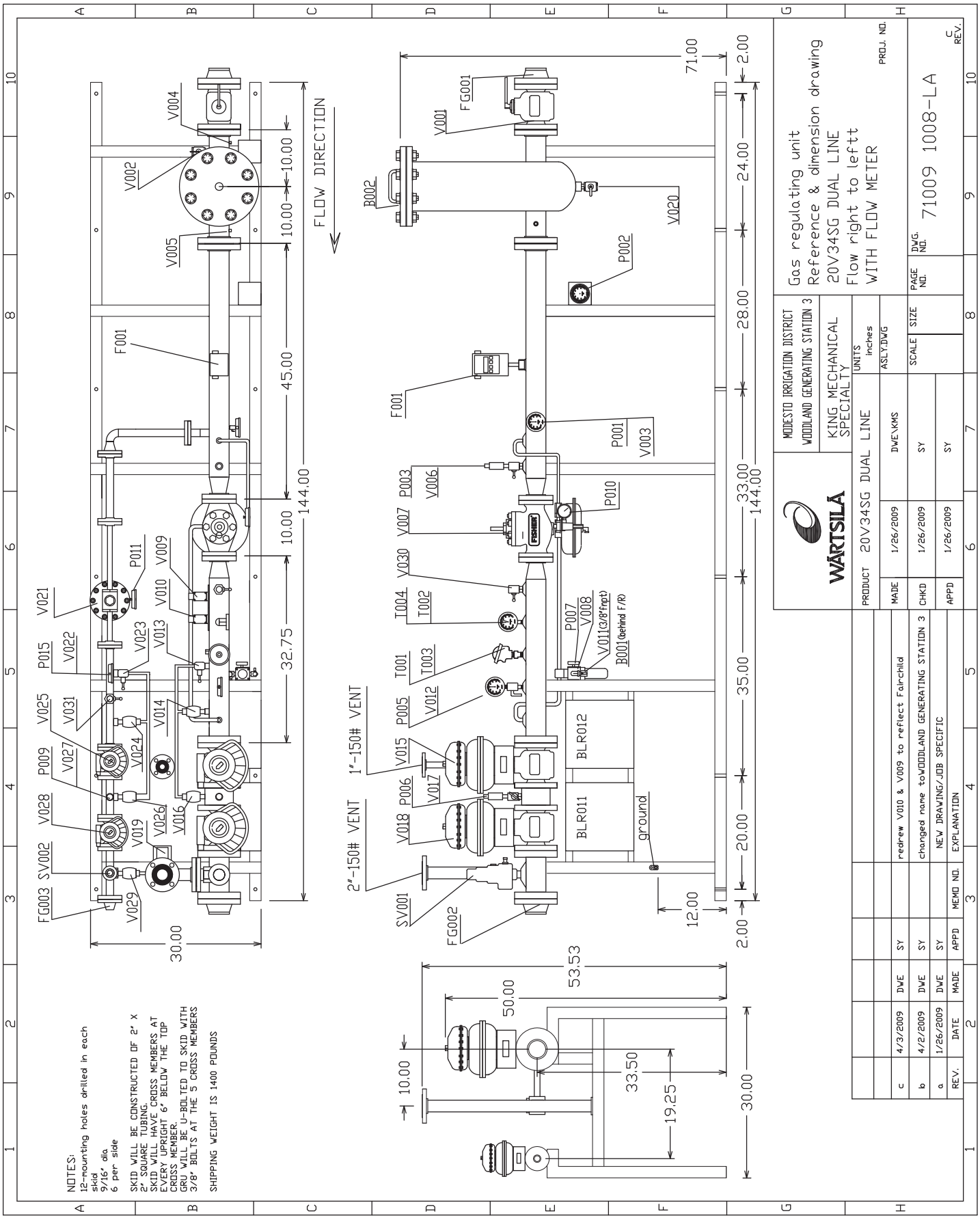

2850
4050
5400
6890
8590
M16x65
STEEL PLATE 5*250*390 3 PCS. (IF NEEDED)
8236



Project name: BBA Budgetary
Project number: TBA
Quotation number: TBA
Document creation date: June 21, 2012

Inside the Power House




NOTES:
12-mounting holes drilled in each skid
9/16" dia.
6 per side
SKID WILL BE CONSTRUCTED OF 2" X 2" SQUARE TUBING.
SKID WILL HAVE CROSS MEMBERS AT EVERY UPRIGHT 6" BELOW THE TOP CROSS MEMBER.
GRU WILL BE U-BOLTED TO SKID WITH 3/8" BOLTS AT THE 5 CROSS MEMBERS
SHIPPING WEIGHT IS 1400 POUNDS
FLOW DIRECTION
1"-150# VENT
2"-150# VENT
ground
BLR012
BLR011
MODESTO IRRIGATION DISTRICT
WOODLAND GENERATING STATION 3
KING MECHANICAL SPECIALTY
WÄRTSILÄ
PRODUCT 20V34SG DUAL LINE
Gas regulating unit
Reference & dimension drawing
20V34SG DUAL LINE
Flow right to leftt
WITH FLOW METER
71009 1008-LA
REV. C
REV. | DATE | MADE | APPD | MEMO NO. | EXPLANATION
c | 4/3/2009 | DWE | SY | redrew V010 & V009 to reflect Fairchild
b | 4/2/2009 | DWE | SY | changed name toWOODLAND GENERATING STATION 3
a | 1/26/2009 | DWE | SY | NEW DRAWING/JOB SPECIFIC

Appendix F

General Contractor References

Enerserv Quotation

Au service de l'énergie

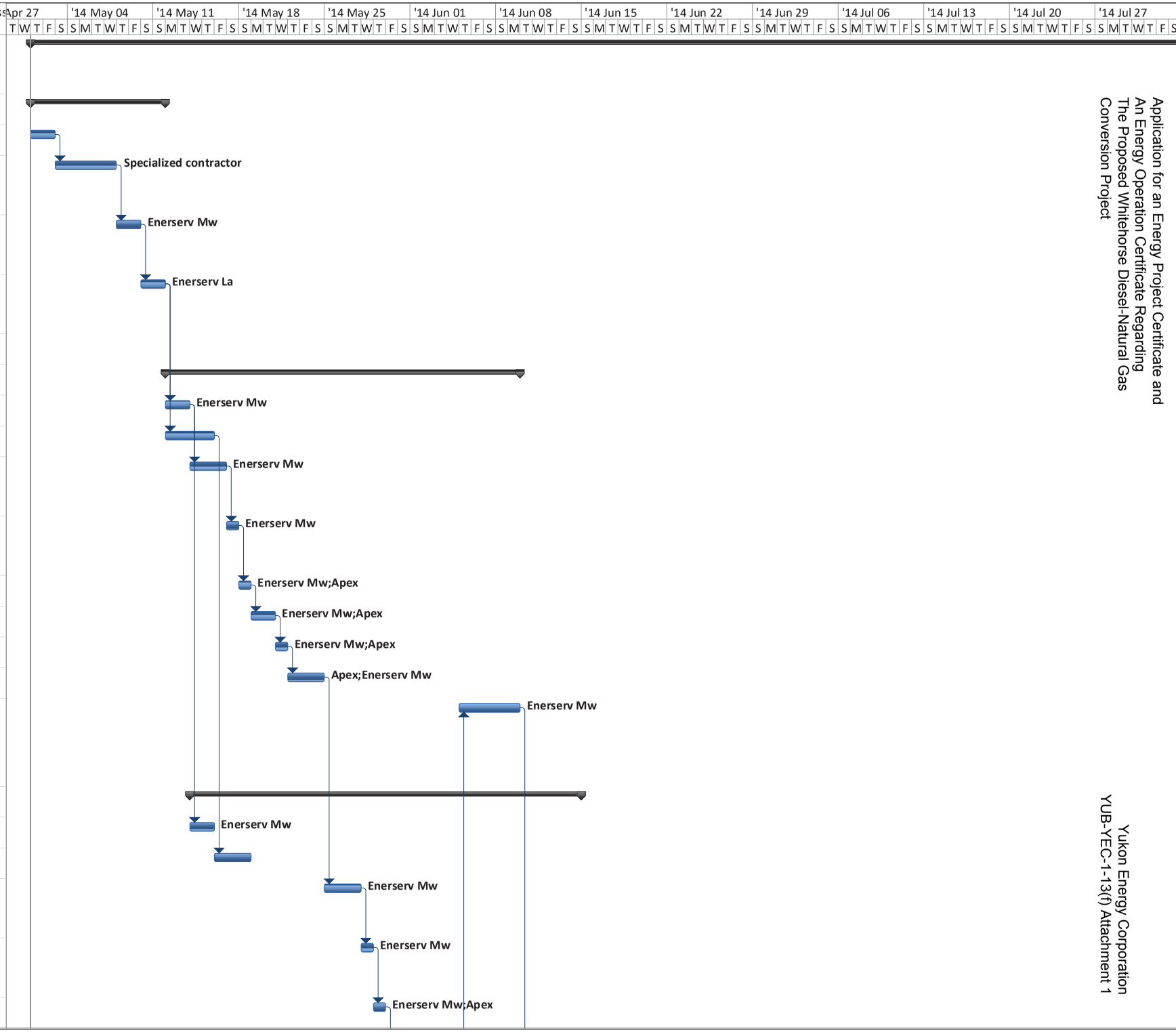
EnerServ

Budget

Client : BBA **Customer :**	**Projet #:** WD1 & WD2 **Project #:** Replacement rev 1	**Date :**	2013-02-06 aaaa-mm-jj / yyyy-mm-dd

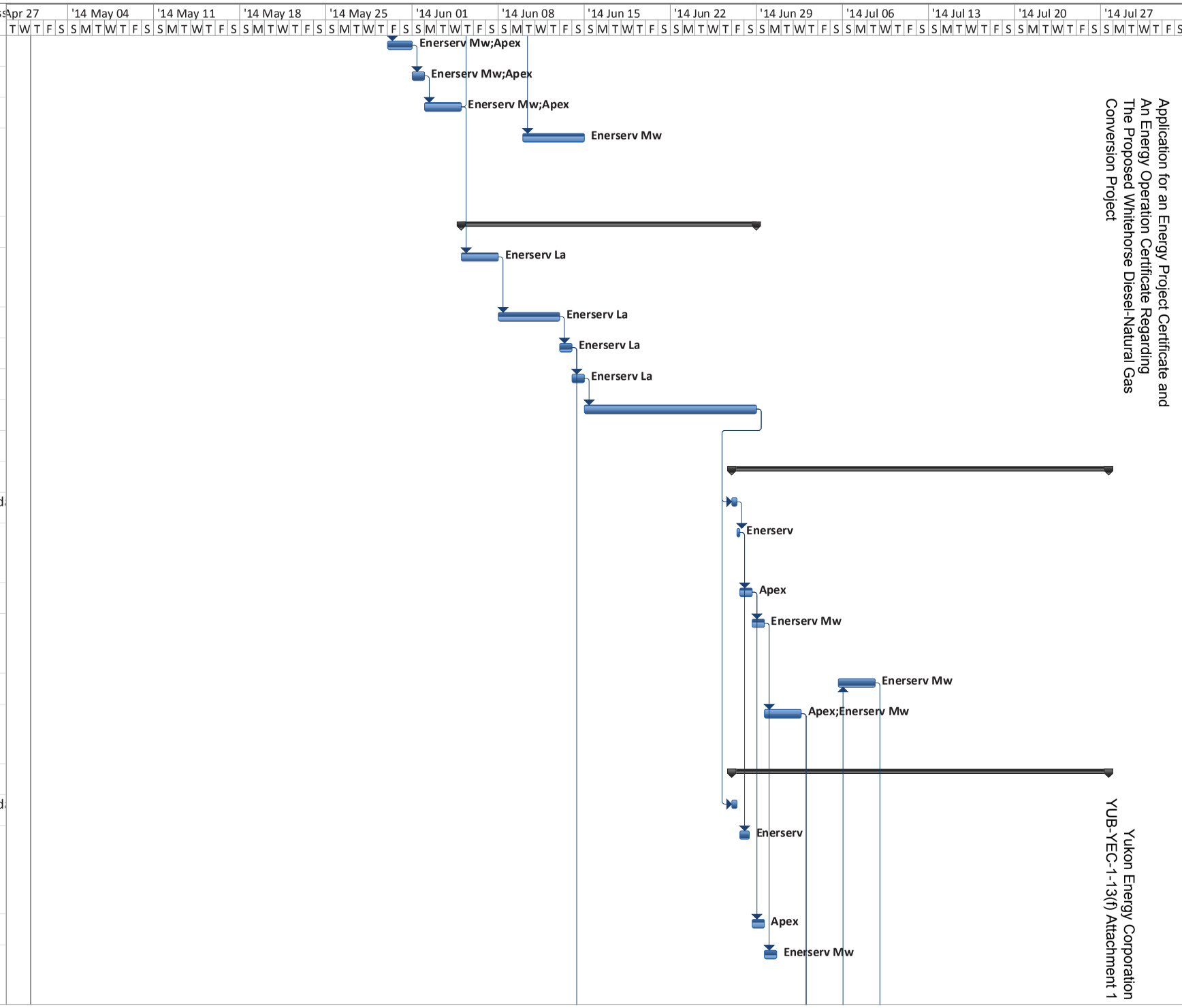
Préparation	80 heures	9 200,00 $
Ingénierie	0 heures	- $
Gestion Projet	140 heures	16 100,00 $
Mobilisation Démobilisation	336 heures	47 700,00 $
Travaux	5500 heures	529 665,00 $
Sous-Traitant		51 750,00 $
Outillage		43 980,00 $
Rapport	0 heures	- $
Sous-Total		698 395,00 $
Consommables		1,50%
Grand Total		708 870,93 $

on	Start	Finish	Predecess
4	**Thu 14-05-01**	**Tue 14-08-12**	
ys	**Thu 14-05-01**	**Sun 14-05-11**	
s	Thu 14-05-01	Fri 14-05-02	
s	Sat 14-05-03	Wed 14-05-07	3
s	Thu 14-05-08	Fri 14-05-09	4
s	Sat 14-05-10	Sun 14-05-11	5
ys	**Mon 14-05-12**	**Mon 14-06-09**	
s	Mon 14-05-12	Tue 14-05-13	6
s	Mon 14-05-12	Thu 14-05-15	6
s	Wed 14-05-14	Fri 14-05-16	9
	Sat 14-05-17	Sat 14-05-17	11
	Sun 14-05-18	Sun 14-05-18	12
s	Mon 14-05-19	Tue 14-05-20	13
	Wed 14-05-21	Wed 14-05-21	14
s	Thu 14-05-22	Sat 14-05-24	15
s	Thu 14-06-05	Mon 14-06-09	26
ys	**Wed 14-05-14**	**Sat 14-06-14**	
s	Wed 14-05-14	Thu 14-05-15	9
s	Fri 14-05-16	Sun 14-05-18	10
s	Sun 14-05-25	Tue 14-05-27	16
	Wed 14-05-28	Wed 14-05-28	21
	Thu 14-05-29	Thu 14-05-29	22



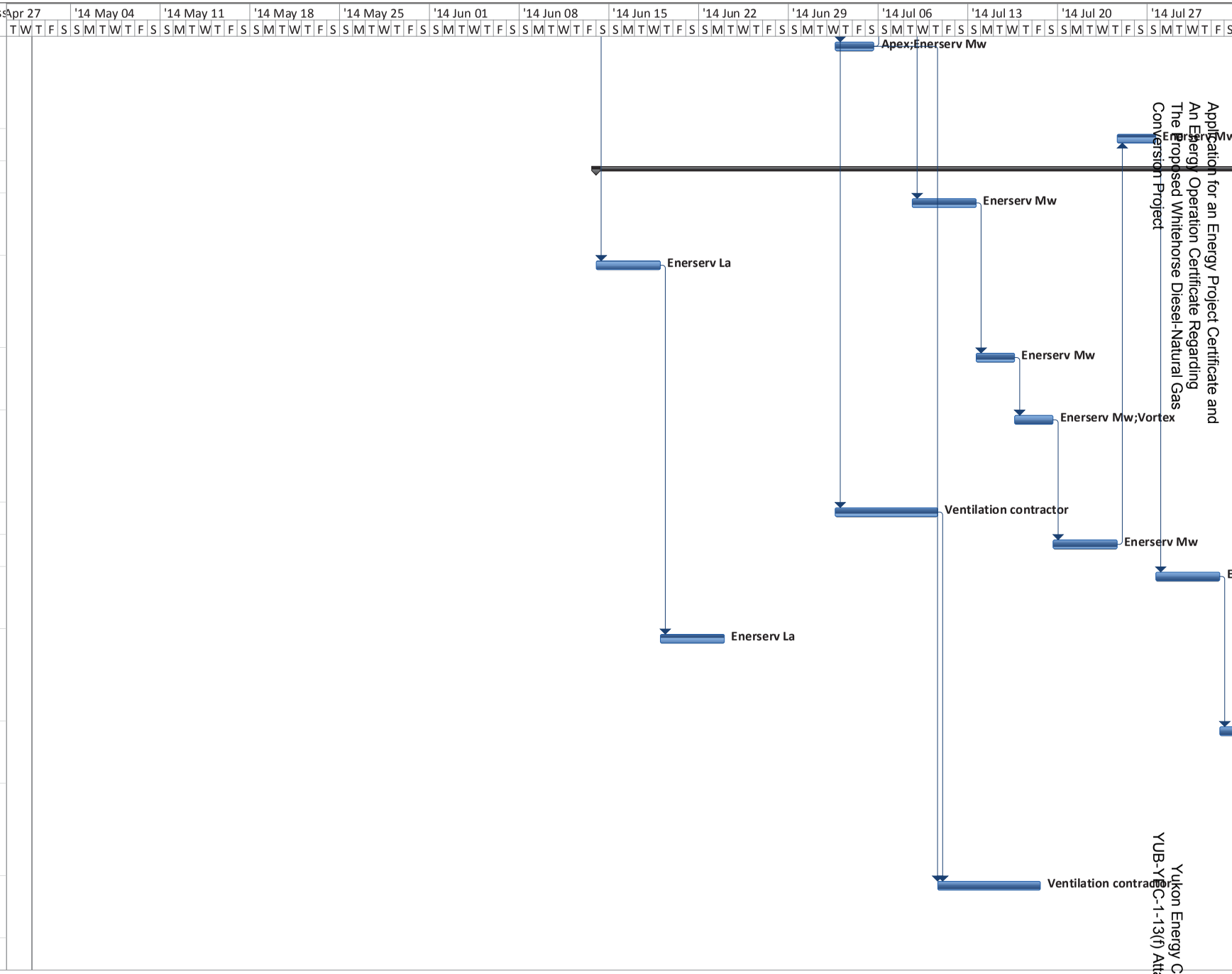
Récapitulative
Jalons externes
Récapitulatif inactif
Report récapitulatif manuel
Fin uniquement
Récapitulatif du projet
Tâche inactive
Tâche manuelle
Récapitulatif manuel
Échéance
Tâches externes
Jalon inactif
Durée uniquement
Début uniquement
Avancement

on	Start	Finish	Predecess
s	Fri 14-05-30	Sat 14-05-31	23
	Sun 14-06-01	Sun 14-06-01	24
s	Mon 14-06-02	Wed 14-06-04	25
s	Tue 14-06-10	Sat 14-06-14	17
ys	**Thu 14-06-05**	**Sat 14-06-28**	
s	Thu 14-06-05	Sat 14-06-07	26
s	Sun 14-06-08	Thu 14-06-12	29
	Fri 14-06-13	Fri 14-06-13	30
	Sat 14-06-14	Sat 14-06-14	31
ys	Sun 14-06-15	Sat 14-06-28	32
days	**Fri 14-06-27**	**Sun 14-07-27**	
	Fri 14-06-27	Fri 14-06-27	33FS-2 d
ays	Fri 14-06-27	Fri 14-06-27	36
	Fri 14-06-27	Sat 14-06-28	37
	Sat 14-06-28	Sun 14-06-29	38
s	Sat 14-07-05	Tue 14-07-08	47
s	Sun 14-06-29	Wed 14-07-02	39
days	**Fri 14-06-27**	**Sun 14-07-27**	
	Fri 14-06-27	Fri 14-06-27	33FS-2 d
ays	Fri 14-06-27	Sat 14-06-28	37
	Sat 14-06-28	Sun 14-06-29	38
	Sun 14-06-29	Mon 14-06-30	39



Récapitulative
Récapitulatif du projet
Tâches externes
Jalons externes
Tâche inactive
Jalon inactif
Récapitulatif inactif
Tâche manuelle
Durée uniquement
Report récapitulatif manuel
Récapitulatif manuel
Début uniquement
Fin uniquement
Échéance
Avancement

on	Start	Finish	Predecess
s	Wed 14-07-02	Sat 14-07-05	41
s	Thu 14-07-24	Sun 14-07-27	55
days	**Sat 14-06-14**	**Tue 14-08-12**	
s	Tue 14-07-08	Sun 14-07-13	40
s	Sat 14-06-14	Wed 14-06-18	31
s	Sun 14-07-13	Wed 14-07-16	50
s	Wed 14-07-16	Sat 14-07-19	52
s	Wed 14-07-02	Thu 14-07-10	41
s	Sat 14-07-19	Thu 14-07-24	53
s	Sun 14-07-27	Fri 14-08-01	48
s	Thu 14-06-19	Mon 14-06-23	51
s	Fri 14-08-01	Mon 14-08-04	56
s	Mon 14-08-04	Thu 14-08-07	58
s	Thu 14-07-10	Fri 14-07-18	47;54
s	Tue 14-08-07	Tue 14-08-12	59



Application for an Energy Project Certificate and An Energy Operation Certificate Regarding The Proposed Whitehorse Diesel-Natural Gas Conversion Project

Yukon Energy Corporation YUB-YEC-1-13(f) Attachment 1

e	Récapitulative	Jalons externes	Récapitulatif inactif	Report récapitulatif manuel	Fin uniquement	]
tionnement	Récapitulatif du projet	Tâche inactive	Tâche manuelle	Récapitulatif manuel	Échéance	
	Tâches externes	Jalon inactif	Durée uniquement	Début uniquement	Avancement	

Apex Industrial Movers and Pro-Tech Industrial Movers
8035 Alexander Road, Delta, B.C. V4G 1C6
Apex Ph: 604-293-0278 PIM Ph: 604-946-9665
Fax: 604-946-0623

Divisions of Pacific Industrial Movers LP, part of the PACIFIC group of Companies

February 4, 2013

Enerserv Inc
1117 Roberval
South Granby, QC J2J 0N3
Email: carl@enerserv.ca

Apex Reference #2013111

Attention: Mr. Carl Richard

Dear Mr. Richard:

Re: Mobilization, Demobilization and Crew and Equipment Daily Rate

We understand that the generators weight 120 ton each.

I have broken the quotation into two separate parts. The first part is for the mobilization and demobilization of crew and equipment. The second part is the daily rate for our crew and equipment.

Part 1 – Mobilization and Demobilization:

Project Location:
Delta and Whitehorse

Scope of Work:
- Apex will mobilize our crew and equipment to Whitehorse
- We will demobilize our crew and equipment to Delta

Price for the above defined work per occurance..... $36,200.00 CDN
(Price for two occurrences..... $72,400.00 CDN)

Proposal Includes:
- Mobilization and demobilization
- Crew and jacking equipment
- Meals and lodging
- Fuel surcharge

Part 2 – Jacking and Sliding Generators to Pad – Daily Rate:

Project Location:
Whitehorse

Scope of Work:
- Apex's crew will jack and slide the generator from the transport trailer and place it to the pad

Price for the daily rate……..... $5,925.00 CDN

Proposal Includes:
- Foreman
- Rigging crew (three)
- Jack and sliding gear
- Meals and lodging
- Fuel surcharge

Proposal Does Not Include:
- Transporting of the generators to site
- Any indoctrination at the site
- Premium time rates for Saturday or Sunday; The premium time rates are as follows:
- Saturday
    - Foreman – $32.00 per hour
    - Riggers – $32.00 per hour – three riggers
- Sunday
    - Foreman – $64.00 per hour
    - Riggers – $64.00 per hour – three riggers

Subjects:
- To free and clear access to the offloading location and the generator pads

---

Please review the below noted General Conditions of Quotation. In addition to other issues, this attachment contains important facts regarding our insurance coverage. Canadian HST is not included in this quotation. Our operations department will generate a work procedure for our work, however, any engineer stamped documents or drawings, if required, will be additional to this quotation.

We sincerely appreciate the opportunity to quote your requirements. If we can be of any further assistance, please do not hesitate to contact us at (604) 293-0278.

Sincerely,

Doug Elliot

De : Carl Richard [mailto:carl@enerserv.ca]
Envoyé : 7 février 2013 14:40
À : 'Gagnon, Christian'
Cc : 'bruno@enerserv.ca'; 'Clinton, Tyson'; 'Desage, Christophe'; 'Marcoux, Jocelyn'
Objet : RE: Energy-5954018-proposition budgétaire pour l'installation de (2) nouvelles génératrices

Christian

Tel que demandé voici la révision pour un horaire de 70h par semaine.

Merci

Carl Richard
Conseiller Technique Senior - Senior Tehnical Field Advisor

EnerServ

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De : Gagnon, Christian [mailto:Christian.Gagnon@bba.ca]
Envoyé : 7 février 2013 10:31
À : 'Carl Richard'
Cc : bruno@enerserv.ca; Clinton, Tyson; Desage, Christophe; Marcoux, Jocelyn
Objet : RE: Yukon Energy-5954018-proposition budgétaire pour l'installation de (2) nouvelles génératrices

Bonjour Carl,

Un petit point pour la proposition budgétaire mais néanmoins important. Est-ce possible de corriger sur les entêtes et de me retourner les documents?
Le projet est pour **WD1 et WD2**. (Mention WD2 et WD3)

Également, nos hypothèses sont basées sur 70 heures / semaine (10 heures par jour).

De : Carl Richard [mailto:carl@enerserv.ca]
Envoyé : 6 février 2013 22:41
À : Gagnon, Christian
Cc : bruno@enerserv.ca
Objet : RE: Yukon Energy-5954018-proposition budgétaire pour l'installation de (2) nouvelles génératrices

Christian

Tel que convenu voici mon estimé du projet. Désolé si je n'ai pas eu le temps de vous faire un estimé formel mais l'information qui vous intéresse est dans le texte qui suit.

1- Nous avons assumé que l'horaire de travail est de 50h par semaine donc 5 jours de 10h.
2- Il y aurait une démobilisation partiel du site durant le murissement du béton. Dans cette période il y aurait seulement 2 journaliers sur site pour préparer les bases de béton des cooling system (à l'extérieur du batiment)
3- Pour les travaux de manutention lourd (sans grue) nous utilisons un contracteur spécialisé.
4- Dans l'échéancier nous avons mentionner les travaux de ventilation par un contracteur mais je n'ai pas de provision dans mon budget pour ces travaux il en va de même pour les travaux électrique.
5- L'équipe prévu pour Enerserv dans le budget est : 1 ingénieur / chargé de projet, 4 mécaniciens, 2 journaliers, et 1 soudeur (fourni par Vortex)
6- Dans le budget nous avons inclus les outils, camion, logement, consommables, béton, 10k de matériaux de construction divers et 2 mobilisation et démobilisation.
7- Nous avons assumé que toute la tuyauterie était fourni pré fabriqué par Vortex. Nous avons tout de même prévu un soudeur pour faire le dernier spool sur site pour l'ajustement final.

Estimation des travaux

Enerserv : 683 000$
Déménageur industriel : 180 000 (Il y a probablement moyen d'optimiser pour réduire leur temps sur site et couper la facture de 30 000)

Merci

Carl Richard
Conseiller Technique Senior - Senior Tehnical Field Advisor

EnerServ

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De : Gagnon, Christian
Envoyé : 16 janvier 2013 12:21
À : 'carl@enerserv.ca'
Cc : Clinton, Tyson
Objet : RE: Yukon Energy-5954018-proposition budgétaire pour l'installation de (2) nouvelles génératrices

Bonjour Carl,

SVP Prévoir la proposition budgétaire en **Anglais**

Merci

Christian Gagnon, tech.
Chargé de projet, Service Mécanique-Énergie

BBA inc. 375, boul. Sir-Wilfrid-Laurier, Mont-Saint-Hilaire, Québec J3H 6C3 CANADA
T +1 450.464.2111, poste 5929 **F** +1 450.464.0901
Courriel : christian.gagnon@bba.ca Site Internet : bba.ca

De : Gagnon, Christian
Envoyé : 16 janvier 2013 09:53
À : 'carl@enerserv.ca'
Cc : Clinton, Tyson
Objet : Yukon Energy-5954018-proposition budgétaire pour l'installation de (2) nouvelles génératrices

Bonjour Carl,

Objet : Yukon Energy-Whitehorse

Suite à notre discussion, tu trouveras en pièces jointes quelques documents de référence et photos.

Étendue des travaux

- Enlèvement et disposition hors du site des (2) génératrices Mirrlees (WD1 et WD2) ainsi que des auxiliaires associés (conduits à fumée, tuyauteries).
- Mise à niveau des ''Mounting blocks'' existants. Remplir les cavités pour supporter les nouvelles génératrices.
- Installation de (2) nouvelles génératrices d'environ 6.7 MW Dual fuel (Gaz naturel et diesel).
- Installation des radiateurs à l'extérieur sur des bases de béton.
- Inclure les coûts associés à la mobilisation, frais de transport, hébergement, dépenses et à la démobilisation.
- Inclure dans la proposition les coûts pour les équipements de levage requis pour les activités mentionnés.

L'échéancier préliminaire pour ces travaux prévoit ces travaux à la fin du printemps/été 2014. Le but est de mettre en service au moins une génératrice vers la fin de l'été.

Les génératrices actuelles ont un poids similaire au nouvelle. Voir dessin ci-joint. La WD1 et WD2 sont un peu différente cependant en poids et en dimensions.
Les nouvelles génératrices auraient un poids approximatif de 120 T.

Les dimensions des nouvelles seraient d'environ :
L:11.3 m (37 ft)
H: 4.472 m (11 ft)
W: 3.3 m (15 ft)
L'installation est prévue sur les Mounting Blocks existants. Par contre, les nouvelles génératrices seraient montés directement sur une base

Tel que discuté, ne pas inclure pour le moment:

- Les travaux de tuyauterie.
- Les travaux électrique.
- Les travaux pour les conduits à fumée (exhaust stack)
- Le transport des nouvelles génératrices jusqu'au site.
- Nous te reviendrons avec des données plus précises à cet effet dans quelques semaines si tu as de l'intérêt pour ces travaux également.

Si tu as besoin d'autres photos, je pourrais t'acheminer celles-ci éventuellement par le biais d'un site ftp ou autre.

SVP Nous acheminer ta proposition budgétaire pour le 1 février.

Si tu as des questions, n'hésite pas à me contacter.

Merci de ta collaboration.

Salutations,

Christian Gagnon, tech.
Chargé de projet, Service Mécanique-Énergie

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Appendix G

Cost Estimate

Summary Cost Estimate

BBA

Yukon Energy Corporation
Whitehorse Power Plant (P126)
WD1 and WD2 Replacement

Costs Summary

Document :	Summary cost report
Revison :	R02
Description :	Conventional Project Mode
Date :	2013-02-21
Project :	5954018
Client project no. :	
Prepared by :	Christian Gagnon
Checked by :	Christophe Desage

Direct costs summary

	Total Material	Total Labour	Total
Supply of Generators and Auxilia	11,000,000 $	0 $	11,000,000 $
Installation Contract	1,426,112 $	3,408,369 $	4,834,481 $
Electrical - High Voltage	613,540 $	92,540 $	706,080 $
Contingency	2,062,617 $	683,416 $	2,746,033 $
Direct costs total:	15,102,270 $	4,184,325 $	19,286,594 $

Indirect costs summary

	Total Expenses	Total Labour	Total
Commissioning and Start-Up	20,000 $	320,000 $	340,000 $
Professional Services	280,000 $	3,301,200 $	3,581,200 $
Owners Cost	1,003,000 $	1,351,030 $	2,354,030 $
Freight	2,733,430 $	0 $	2,733,430 $
Spare Parts and First Fill	210,000 $	0 $	210,000 $
Contingency:	890,226 $	995,101 $	1,885,327 $
Indirect costs total	5,136,656 $	5,967,331 $	11,103,987 $
Grand Total:	20,238,926 $	10,151,656 $	30,390,582 $

BBA	Whitehorse Diesel Generating Plant Conversion and Upgrades **Stage 1 – WD1 and WD2 Replacement** **Final Report and Cost Estimate**	YUKON ENERGY

Summary by Sub-Sector Cost Estimate

BBA

Yukon Energy Corporation
Whitehorse Power Plant (P126)
WD1 and WD2 Replacement

Costs Summary

Document :	Summary cost report
Revison :	R02
Description :	Conventional Project Mode
Date :	2013-02-19
Project :	5954018
Client project no. :	
Prepared by :	Christian Gagnon
Checked by :	Christophe Desage

Direct costs summary

		Total Material	Total Labour	Total
Supply of Generators and Auxiliary Equipment		**11,000,000 $**	**0 $**	**11,000,000 $**
		11,000,000 $	0 $	11,000,000 $
Installation Contract		**1,426,112 $**	**3,408,369 $**	**4,834,481 $**
A- Demolition work		5,000 $	342,500 $	347,500 $
B- Installation of New Generators		111,600 $	720,900 $	832,500 $
C- Diesel System		102,695 $	83,572 $	186,267 $
D- Natural Gas System		37,700 $	196,770 $	234,470 $
E- Lubricating Oil System		33,190 $	90,944 $	124,134 $
F- Compressed Air Systems		4,200 $	105,000 $	109,200 $
G- Cooling System		68,608 $	319,353 $	387,960 $
H- Ventilation System		349,860 $	161,722 $	511,581 $
I- Exhaust System		89,670 $	232,025 $	321,695 $
J- Water Treatment System		14,200 $	44,200 $	58,400 $
K- Heating & Heat Recovery Syst		318,590 $	328,344 $	646,934 $
L- Automation Installation		30,000 $	197,800 $	227,800 $
M- Electrical Installation		218,800 $	462,840 $	681,640 $
N- P126 Building Modifications		42,000 $	122,400 $	164,400 $
Electrical - High Voltage		**613,540 $**	**92,540 $**	**706,080 $**
		613,540 $	92,540 $	706,080 $
	Contingency	2,062,617 $	683,416 $	2,746,033 $
	Direct costs total:	15,102,270 $	4,184,325 $	19,286,594 $

Indirect costs summary	Total Expenses	Total Labour	Total
Commissioning and Start-Up	20,000 $	320,000 $	340,000 $
	20,000 $	320,000 $	340,000 $
Professional Services	280,000 $	3,301,200 $	3,581,200 $
A-Engineering	0 $	2,143,800 $	2,143,800 $
B-Procurement	0 $	135,000 $	135,000 $
C-Construction Management	0 $	1,022,400 $	1,022,400 $
D-Expenses	280,000 $	0 $	280,000 $
Owners Cost	1,003,000 $	1,351,030 $	2,354,030 $
A-Financing	480,000 $	0 $	480,000 $
B-Studies	0 $	320,000 $	320,000 $
C-Management	70,000 $	800,800 $	870,800 $
D-Commissioning & Decommissi	0 $	200,200 $	200,200 $
E-Training	0 $	30,030 $	30,030 $
F-Permits	5,000 $	0 $	5,000 $
G-Insurance	0 $	0 $	0 $
H-Escalation	348,000 $	0 $	348,000 $
I-Public Relations & Legal	100,000 $	0 $	100,000 $
Freight	2,733,430 $	0 $	2,733,430 $
	2,733,430 $	0 $	2,733,430 $
Spare Parts and First Fill	210,000 $	0 $	210,000 $
	210,000 $	0 $	210,000 $
Contingency:	890,226 $	995,101 $	1,885,327 $
Indirect costs total:	5,136,656 $	5,967,331 $	11,103,987 $
Grand Total:	20,238,926 $	10,151,656 $	30,390,582 $

BBA	Whitehorse Diesel Generating Plant Conversion and Upgrades **Stage 1 – WD1 and WD2 Replacement** **Final Report and Cost Estimate**	YUKON ENERGY

Detailed Cost Estimate

BBA

Yukon Energy Corporation
Whitehorse Power Plant (P126)
WD1 and WD2 Replacement

Cost Estimate

Document :	**Summary cost report**
Revison :	**R02**
Description :	**Conventional Project Mode**
Date :	**2013-02-19**
Project :	**5954018**
Client project no. :	
Prepared by :	**Christian Gagnon**
Checked by :	**Christophe Desage**

Item	*Description*	*Package #*	*Qty*	*Unit*	*Unit Price*	*Total Material*	*Cont. %*	*Cont. Mat.*	*M.H. Unit*	*M.H. Total*	*Total M.H.*	*Cont. %*	*Cont. M.H.*	*Total*
Supply of Generators and Auxiliary Equipment														
	Generators dual fuel 6.7 MW with auxiliary equipment		2	Unit(s)	5,500,000 $	11,000,000 $	15	1,650,000 $	0.00		0	0 $	0	0 $	12,650,000 $
		Total subsection				11,000,000 $		1,650,000 $			0	0 $		0 $	12,650,000 $
		Total section				11,000,000 $		1,650,000 $			0	0 $		0 $	12,650,000 $

Item	Description	Package #	Qty	Unit	Unit Price	Total Material	Cont. %	Cont. Mat.	M.H. Unit	M.H. Total	Total M.H.	Cont. %	Cont. M.H.	Total
Installation Contract														
	A- Demolition work													
	Opening of the building for the removal of the two Mirrlees generators		1	Lot	0 $	0 $	0	0 $	210.00	210	33,600 $	15	5,040 $	38,640 $
	Removal of auxiliary equipment and stack of old generators		1	Lot	0 $	0 $	0	0 $	420.00	420	77,700 $	15	11,655 $	89,355 $
	Removal of existing cables		1	Lot	0 $	0 $	0	0 $	140.00	140	19,600 $	15	2,940 $	22,540 $
	Removal of existing Switchgear from Mirrlees WD1 and WD2 generators		1	Lot	0 $	0 $	0	0 $	140.00	140	19,600 $	15	2,940 $	22,540 $
	Removal of the (2) generators Mirrlees WD1 and WD2		1	Lot	0 $	0 $	0	0 $	600.00	600	111,000 $	15	16,650 $	127,650 $
	Removal of the existing mezzanine and existing ventilation systems		1	Lot	0 $	0 $	0	0 $	280.00	280	51,800 $	15	7,770 $	59,570 $
	Removal of the existing piping of Mirrlees generators		1	Lot	0 $	0 $	0	0 $	140.00	140	22,400 $	15	3,360 $	25,760 $
	Site Preparation & Access to Back side of Bldg.		1	Lot	5,000 $	5,000 $	15	750 $	40.00	40	6,800 $	15	1,020 $	13,570 $
				Total subsection		5,000 $		750 $		1,970	342,500 $		51,375 $	399,625 $

Item	Description	Package #	Qty	Unit	Unit Price	Total Material	Cont. %	Cont. Mat.	M.H. Unit	M.H. Total	Total M.H.	Cont. %	Cont. M.H.	Total
Installation Contract														
B- Installation of New Generators														
	Closing of the building after the entry of the new generators		1	Lot	10,000 $	10,000 $	15	1,500 $	280.00	280	44,800 $	15	6,720 $	63,020 $
	Concrete - Drilling for Rebars & Epoxy set - Mounting Block WD1/WD2		40	Unit(s)	13 $	500 $	15	75 $	5.00	200	27,000 $	15	4,050 $	31,625 $
	Concrete - Cleaning of Existing Bases		2	Unit(s)	2,000 $	4,000 $	15	600 $	40.00	80	10,800 $	15	1,620 $	17,020 $
	Concrete - Generator Mounting Block WD1		15	Meter(s)^3	800 $	12,000 $	15	1,800 $	30.00	450	60,750 $	15	9,113 $	83,663 $
	Concrete - Generator Mounting Block WD2		17	Meter(s)^3	800 $	13,600 $	15	2,040 $	30.00	510	68,850 $	15	10,328 $	94,818 $
	Concrete - WD1 - Non-shrink grout		2	Meter(s)^3	1,000 $	2,000 $	15	300 $	35.00	70	9,450 $	15	1,418 $	13,168 $
	Concrete - WD2 - Non-shrink grout		2	Meter(s)^3	1,000 $	2,000 $	15	300 $	35.00	70	9,450 $	15	1,418 $	13,168 $
	Engine platforms (supply included with Generators)		2	Lot	0 $	0 $	0	0 $	160.00	320	54,400 $	15	8,160 $	62,560 $
	Generators Installation (included reassembly the 2 sections)		2	Lot	0 $	0 $	0	0 $	900.00	1,800	288,000 $	15	43,200 $	331,200 $
	Lifting - Installation of new radiators, stack and auxiliary		2	Lot	0 $	0 $	0	0 $	280.00	560	89,600 $	15	13,440 $	103,040 $
	Mezzanine (new-same size as existing but higher)		5	Ton(s)	3,500 $	17,500 $	15	2,625 $	40.00	200	34,000 $	15	5,100 $	59,225 $
	New Garage Door and Frame		1	Unit(s)	30,000 $	30,000 $	15	4,500 $	60.00	60	10,200 $	15	1,530 $	46,230 $
	Structure - Guards/hand rail/ stairs from generator access and auxiliary equipments		2	Lot	10,000 $	20,000 $	15	3,000 $	40.00	80	13,600 $	15	2,040 $	38,640 $
		Total subsection				111,600 $		16,740 $		4,680	720,900 $		108,135 $	957,375 $

Item	Description	Package #	Qty	Unit	Unit Price	Total Material	Cont. %	Cont. Mat.	M.H. Unit	M.H. Total	Total M.H.	Cont. %	Cont. M.H.	Total
Installation Contract														
C- Diesel System														
	Concrete foundation for day tank		1	Meter(s)³	495 $	495 $	15	74 $	7.20	7	972 $	15	146 $	1,687 $
	Diesel auxiliary components		2	Lot	10,000 $	20,000 $	15	3,000 $	40.00	80	12,800 $	15	1,920 $	37,720 $
	Diesel Control panel		2	Unit(s)	4,000 $	8,000 $	40	3,200 $	20.00	40	6,400 $	40	2,560 $	20,160 $
	Diesel day tank Double wall 2300 Liters		2	Unit(s)	5,000 $	10,000 $	15	1,500 $	20.00	40	6,400 $	15	960 $	18,860 $
	Diesel feed pump 2"		2	Unit(s)	4,000 $	8,000 $	15	1,200 $	20.00	40	6,400 $	15	960 $	16,560 $
	Diesel Flow meter 2"		2	Unit(s)	5,000 $	10,000 $	40	4,000 $	10.00	20	3,200 $	40	1,280 $	18,480 $
	Diesel strainer 2"		2	Unit(s)	2,000 $	4,000 $	15	600 $	5.00	10	1,600 $	15	240 $	6,440 $
	Diesel transfer pump 2" (package skid mounted with control panel)		1	Unit(s)	30,000 $	30,000 $	15	4,500 $	30.00	30	4,800 $	15	720 $	40,020 $
	Piping 2" CS sch. 80 / fit.3000 and valves class 800 diesel system inside engine hall		60	Meter(s)	70 $	4,200 $	15	630 $	4.20	252	37,800 $	15	5,670 $	48,300 $
	Water separator		1	Unit(s)	8,000 $	8,000 $	15	1,200 $	20.00	20	3,200 $	15	480 $	12,880 $
				Total subsection		102,695 $		19,904 $		539	83,572 $		14,936 $	221,107 $
D- Natural Gas System														
	Gas detection system		1	Unit(s)	2,000 $	2,000 $	40	800 $	20.00	20	3,200 $	40	1,280 $	7,280 $
	Gas Flow meter		1	Unit(s)	7,000 $	7,000 $	40	2,800 $	20.00	20	3,200 $	40	1,280 $	14,280 $
	Gas Flow meter installation (supply included with Generators)		1	Unit(s)	0 $	0 $	0	0 $	20.00	20	3,200 $	40	1,280 $	4,480 $
	Natural Gas System Equipment (gas train / supply included with Generators / skid mounted)		2	Unit(s)	0 $	0 $	0	0 $	40.00	80	12,800 $	15	1,920 $	14,720 $
	Piping - Natural gas - Welding of future connexions 6" for the existing generators (blank flanges for future use)		5	Unit(s)	500 $	2,500 $	15	375 $	20.00	100	16,000 $	15	2,400 $	21,275 $
	Piping 3" CS sch.40 Vent pipe natural gas system		60	Meter(s)	95 $	5,700 $	15	855 $	4.90	294	30,870 $	15	4,631 $	42,056 $
	Piping 6" CS sch. 40 and valves class 150 natural gas system inside engine hall		100	Meter(s)	205 $	20,500 $	15	3,075 $	8.50	850	127,500 $	15	19,125 $	170,200 $
				Total subsection		37,700 $		7,905 $		1,384	196,770 $		31,916 $	274,291 $

Item	Description	Package #	Qty	Unit	Unit Price	Total Material	Cont. %	Cont. Mat.	M.H. Unit	M.H. Total	Total M.H.	Cont. %	Cont. M.H.	Total
Installation Contract														
E- Lubricating Oil System														
	Concrete foundations for lubricating oil service tank		1	Meter(s)³	495 $	495 $	15	74 $	7.20	7	972 $	15	146 $	1,687 $
	Concrete foundations for lubricating oil storage tank		1	Meter(s)³	495 $	495 $	15	74 $	7.20	7	972 $	15	146 $	1,687 $
	Lubricating and Control Valves - Installation of Equipment (supply included with Generators)		1	Lot	0 $	0 $	0	0 $	140.00	140	22,400 $	15	3,360 $	25,760 $
	Lubricating -Equipment for oil storage tank		2	Unit(s)	2,000 $	4,000 $	15	600 $	40.00	80	12,800 $	15	1,920 $	19,320 $
	Lubricating oil storage tank for fresh oil 5000 liters		1	Unit(s)	10,000 $	10,000 $	15	1,500 $	30.00	30	4,800 $	15	720 $	17,020 $
	Lubricating oil unloading pump unit : fresh oil		2	Unit(s)	2,000 $	4,000 $	15	600 $	20.00	40	6,400 $	15	960 $	11,960 $
	Lubricating oil used / service tank 5000 liters		1	Unit(s)	10,000 $	10,000 $	15	1,500 $	30.00	30	4,800 $	15	720 $	17,020 $
	Piping 2" CS sch. 80 / fit.3000 and valves class 800 lubricating fresh oil system inside engine hall		30	Meter(s)	70 $	2,100 $	15	315 $	4.20	126	18,900 $	15	2,835 $	24,150 $
	Piping 2" CS sch. 80 / fit.3000 and valves class 800 lubricating service oil system inside engine hall		30	Meter(s)	70 $	2,100 $	15	315 $	4.20	126	18,900 $	15	2,835 $	24,150 $
				Total subsection		33,190 $		4,979 $		586	90,944 $		13,642 $	142,754 $
F- Compressed Air Systems														
	Compressed Air Systems (Start-up and Instrument air) Installation (supply included with Generators)		2	Lot	0 $	0 $	0	0 $	210.00	420	67,200 $	15	10,080 $	77,280 $
	Piping 2" CS Steel sch.40 and valves for compressed air system (set)		60	Meter(s)	70 $	4,200 $	15	630 $	4.20	252	37,800 $	15	5,670 $	48,300 $
				Total subsection		4,200 $		630 $		672	105,000 $		15,750 $	125,580 $

Item	Description	Package #	Qty	Unit	Unit Price	Total Material	Cont. %	Cont. Mat.	M.H. Unit	M.H. Total	Total M.H.	Cont. %	Cont. M.H.	Total
Installation Contract														
G- Cooling System														
	Concrete Above Ground - Radiators Foundation Pedestrals		1	Meter(s)³	925 $	925 $	15	139 $	45.00	45	6,075 $	15	911 $	8,050 $
	Concrete Foundation - Radiators Footings		12	Meter(s)³	505 $	6,060 $	15	909 $	9.00	108	14,580 $	15	2,187 $	23,736 $
	Cooling System and Control valves Installation (supply included with Generators)		2	Lot	0 $	0 $	0	0 $	210.00	420	67,200 $	40	26,880 $	94,080 $
	Earth Excavation Radiators		130	Meter(s)³	6 $	748 $	15	112 $	0.20	26	4,810 $	15	722 $	6,391 $
	Grating (Exterior Access platform)		1	Lot	3,500 $	3,500 $	15	525 $	20.00	20	3,200 $	15	480 $	7,705 $
	Heat Exchangers and Control valves Installation - HT and LT network (Supply included with Generators)		2	Unit(s)	0 $	0 $	0	0 $	140.00	280	44,800 $	40	17,920 $	62,720 $
	Piping 2" CS sch. 40 and valves class 800 cooling system (diesel cooler) inside engine hall		60	Meter(s)	60 $	3,600 $	15	540 $	4.20	252	40,320 $	15	6,048 $	50,508 $
	Piping 8" CS sch. 40 and valves class 150 cooling system (jacket) inside engine hall		60	Meter(s)	310 $	18,600 $	15	2,790 $	11.40	684	109,440 $	15	16,416 $	147,246 $
	Radiator Panels (Supply included with Generators)		2	Unit(s)	0 $	0 $	0	0 $	20.00	40	6,400 $	40	2,560 $	8,960 $
	Stairs (Exterior Access platform)		15	Meter(s)	2,000 $	30,000 $	15	4,500 $	8.00	120	20,400 $	15	3,060 $	57,960 $
	Structural Backfill - Radiators		115	Meter(s)³	45 $	5,175 $	15	776 $	0.10	12	2,128 $	15	319 $	8,398 $
		Total subsection				68,608 $		10,291 $		2,007	319,353 $		77,503 $	475,754 $
H- Ventilation System														
	Concrete Above Ground - Ventilation Units Foundation Pedestrals		4	Meter(s)³	925 $	3,700 $	15	555 $	45.00	180	24,300 $	15	3,645 $	32,200 $
	Earth Excavation - Ventilation Units		13	Meter(s)³	6 $	75 $	15	11 $	0.20	3	481 $	15	72 $	639 $
	Structural Backfill - Ventilation Units		13	Meter(s)³	45 $	585 $	15	88 $	0.10	1	241 $	15	36 $	949 $
	Structural Steel - Ventilation Units Platform (Outside)		4	Ton(s)	3,500 $	14,000 $	15	2,100 $	40.00	160	27,200 $	15	4,080 $	47,380 $
	Ventilation - Exhaust fan Capacity of 10 000 CFM		1	Unit(s)	6,500 $	6,500 $	15	975 $	30.00	30	4,500 $	15	675 $	12,650 $
	Ventilation - Exhaust fans Capacity of 45 000 CFM		3	Unit(s)	15,000 $	45,000 $	15	6,750 $	80.00	240	36,000 $	15	5,400 $	93,150 $
	Ventilation - System for building. Air intake, Supply fan, heating Coil. Capacity of 10 000 CFM		1	Unit(s)	25,000 $	25,000 $	40	10,000 $	40.00	40	6,000 $	30	1,800 $	42,800 $
	Ventilation - System for generators. Air intake, Supply fan, heating Coil. Capacity of 75 000 CFM		3	Unit(s)	85,000 $	255,000 $	40	102,000 $	140.00	420	63,000 $	30	18,900 $	438,900 $
		Total subsection				349,860 $		122,479 $		1,074	161,722 $		34,608 $	668,668 $

Item	Description	Package #	Qty	Unit	Unit Price	Total Material	Cont. %	Cont. Mat.	M.H. Unit	M.H. Total	Total M.H.	Cont. %	Cont. M.H.	Total
Installation Contract														
I- Exhaust System														
	Concrete Above Ground - Exhaust Duct Supports Foundation Pedestrals		1	Meter(s)³	925 $	925 $	15	139 $	45.00	45	6,075 $	15	911 $	8,050 $
	Concrete Above Ground - Exhaust Stack and Silencer Foundation Pedestrals		1	Meter(s)³	925 $	925 $	15	139 $	45.00	45	6,075 $	15	911 $	8,050 $
	Concrete Foundation - Exhaust Duct Supports Footings		5	Meter(s)³	505 $	2,525 $	15	379 $	9.00	45	6,075 $	15	911 $	9,890 $
	Concrete Foundation - Exhaust Stack and Silencer Footings		12	Meter(s)³	505 $	6,060 $	15	909 $	9.00	108	14,580 $	15	2,187 $	23,736 $
	Earth Excavation Exhaust Duct Supports		50	Meter(s)³	6 $	288 $	15	43 $	0.20	10	1,850 $	15	278 $	2,458 $
	Earth Excavation Exhaust Stack and Silencer		130	Meter(s)³	6 $	748 $	15	112 $	0.20	26	4,810 $	15	722 $	6,391 $
	Exhaust Ductings, Silencer, Stack and components - Installation (supply included with Generators)		2	Lot	0 $	0 $	0	0 $	280.00	560	89,600 $	15	13,440 $	103,040 $
	Opening in the rear wall and sealing		2	Lot	10,000 $	20,000 $	15	3,000 $	140.00	280	44,800 $	15	6,720 $	74,520 $
	Provision for Stack Extension and Hospital Grade Silencer		1	Lot	30,000 $	30,000 $	40	12,000 $	90.00	90	14,400 $	40	5,760 $	62,160 $
	Structural Backfill - Exhaust duct supports		45	Meter(s)³	45 $	2,025 $	15	304 $	0.10	5	833 $	15	125 $	3,286 $
	Structural Backfill - Exhaust stack and silencer		115	Meter(s)³	45 $	5,175 $	15	776 $	0.10	12	2,128 $	15	319 $	8,398 $
	Structural Steel - Exhaust ducts supports		2	Ton(s)	3,500 $	7,000 $	15	1,050 $	40.00	80	13,600 $	15	2,040 $	23,690 $
	Structural Steel - Exhaust Stack and Silencer		4	Ton(s)	3,500 $	14,000 $	15	2,100 $	40.00	160	27,200 $	15	4,080 $	47,380 $
				Total subsection		89,670 $		20,951 $		1,465	232,025 $		38,404 $	381,049 $
J- Water Treatment System														
	Piping 2" CS sch.80 / fit.3000 and valves class 800 Water treatment system		60	Meter(s)	70 $	4,200 $	15	630 $	4.20	252	37,800 $	15	5,670 $	48,300 $
	Water treatment Equipment		1	Unit(s)	10,000 $	10,000 $	40	4,000 $	40.00	40	6,400 $	40	2,560 $	22,960 $
				Total subsection		14,200 $		4,630 $		292	44,200 $		8,230 $	71,260 $

Item	Description	Package #	Qty	Unit	Unit Price	Total Material	Cont. %	Cont. Mat.	M.H. Unit	M.H. Total	Total M.H.	Cont. %	Cont. M.H.	Total
Installation Contract														
K- Heating & Heat Recovery System														
	Automation for Heating network and Heat recovery system (DDC, programming, sensors)		1	Lot	30,000 $	30,000 $	40	12,000 $	280.00	280	42,000 $	40	16,800 $	100,800 $
	Concrete foundation for Heat exchanger - heat recovery system		1	Meter(s)^3	495 $	495 $	20	99 $	7.20	7	972 $	20	194 $	1,760 $
	Concrete foundation for pumps and auxiliary equipment - heat recovery system		1	Meter(s)^3	495 $	495 $	20	99 $	7.20	7	972 $	20	194 $	1,760 $
	Control panel for pumps - Heat recovery system		1	Lot	10,000 $	10,000 $	40	4,000 $	20.00	20	3,000 $	40	1,200 $	18,200 $
	Control Valves and balancing valves for Heat recovery system		1	Lot	20,000 $	20,000 $	40	8,000 $	140.00	140	21,000 $	40	8,400 $	57,400 $
	Expansion tank and glycol tank - Heat recovery system		1	Unit(s)	20,000 $	20,000 $	20	4,000 $	40.00	40	6,000 $	20	1,200 $	31,200 $
	Glycol - Balancing of Heat recovery network		1	Lot	0 $	0 $	0	0 $	40.00	40	6,000 $	20	1,200 $	7,200 $
	Heat Exchanger - Interface with existing boilers network 4 000 000 Btu/hre		1	Unit(s)	20,000 $	20,000 $	20	4,000 $	30.00	30	4,500 $	20	900 $	29,400 $
	Heat Exchangers - Heat Recovery 10 000 000 Btu/hre		2	Unit(s)	40,000 $	80,000 $	20	16,000 $	30.00	60	9,000 $	20	1,800 $	106,800 $
	Piping 4" (avg) CS sch.40 and valves class 150 Heat Recovery Systems		180	Meter(s)	120 $	21,600 $	20	4,320 $	5.70	1,026	153,900 $	20	30,780 $	210,600 $
	Piping 6" CS sch 40 and (6) gate valves 6" class 150 -Return Header - Heat recovery system		1	Lot	8,000 $	8,000 $	20	1,600 $	80.00	80	12,000 $	20	2,400 $	24,000 $
	Piping 6" CS sch 40 and (6) gate valves 6" class 150- Supply Header - Heat recovery system		1	Lot	8,000 $	8,000 $	20	1,600 $	80.00	80	12,000 $	20	2,400 $	24,000 $
	Piping Insulation 2" with clading - Heat recovery network		1	Lot	20,000 $	20,000 $	20	4,000 $	300.00	300	45,000 $	20	9,000 $	78,000 $
	Pump - Interface with existing boilers network 200 USGPM		2	Unit(s)	10,000 $	20,000 $	20	4,000 $	20.00	40	6,000 $	20	1,200 $	31,200 $
	Pumps - Heat recovery system 500 USGPM motor 75 HP		2	Unit(s)	30,000 $	60,000 $	20	12,000 $	20.00	40	6,000 $	20	1,200 $	79,200 $
		Total subsection				318,590 $		75,718 $		2,190	328,344 $		78,869 $	801,521 $

Item	Description	Package #	Qty	Unit	Unit Price	Total Material	Cont. %	Cont. Mat.	M.H. Unit	M.H. Total	Total M.H.	Cont. %	Cont. M.H.	Total
Installation Contract														
L- Automation Installation														
	Control and Instrumentation cables		3000	Meter(s)	10 $	30,000 $	40	12,000 $	0.25	750	105,000 $	40	42,000 $	189,000 $
	Maintenance Systems (Automation / Supply included with Generators)		1	Unit(s)	0 $	0 $	0	0 $	0.00	0	0 $	40	0 $	0 $
	Operator's Station (Automation / Supply included with Generators)		2	Unit(s)	0 $	0 $	0	0 $	0.00	0	0 $	40	0 $	0 $
	Programmation & Integration of Complete System		1	Lot	0 $	0 $	0	0 $	580.00	580	92,800 $	40	37,120 $	129,920 $
		Total subsection				30,000 $		12,000 $		1,330	197,800 $		79,120 $	318,920 $
M- Electrical Installation														
	Cable - 3c - 6 AWG copper conductors 1kV Teck90		1800	Meter(s)	12 $	21,600 $	20	4,320 $	0.25	450	63,000 $	20	12,600 $	101,520 $
	Cable - 3c -12 AWG copper conductors 1kV Teck90		1800	Meter(s)	4 $	7,200 $	20	1,440 $	0.15	270	37,800 $	20	7,560 $	54,000 $
	Cable ladders (drop to Equip.)		360	Meter(s)	160 $	57,600 $	20	11,520 $	3.60	1,296	181,440 $	20	36,288 $	286,848 $
	Cable Tray 12"		100	Meter(s)	170 $	17,000 $	20	3,400 $	3.80	380	53,200 $	20	10,640 $	84,240 $
	Connection - 3c - 6 AWG copper conductors 1kV Teck90		120	Unit(s)	20 $	2,400 $	20	480 $	0.50	60	8,400 $	20	1,680 $	12,960 $
	Connection - 3c -12 AWG copper conductors 1kV Teck90		120	Unit(s)	25 $	3,000 $	20	600 $	0.75	90	12,600 $	20	2,520 $	18,720 $
	Low Voltage Installation - 600 Volt and less (Supply included with Generators)		2	Lot	0 $	0 $	0	0 $	280.00	560	78,400 $	20	15,680 $	94,080 $
	MCC-Motor Control Center		1	Unit(s)	110,000 $	110,000 $	20	22,000 $	200.00	200	28,000 $	20	5,600 $	165,600 $
		Total subsection				218,800 $		43,760 $		3,306	462,840 $		92,568 $	817,968 $
N- P126 Building Modifications														
	Structural Members - Building Reinforcement Bracing Cables 7/8 in.		1	Ton(s)	30,000 $	30,000 $	20	6,000 $	400.00	400	68,000 $	20	13,600 $	117,600 $
	Structural Members - Building Reinforcement cold form girts		1	Ton(s)	12,000 $	12,000 $	20	2,400 $	320.00	320	54,400 $	20	10,880 $	79,680 $
		Total subsection				42,000 $		8,400 $		720	122,400 $		24,480 $	197,280 $
		Total section				1,426,112 $		349,136 $		22,215	3,408,369 $		669,535 $	5,853,152 $

Item	Description	Package #	Qty	Unit	Unit Price	Total Material	Cont. %	Cont. Mat.	M.H. Unit	M.H. Total	Total M.H.	Cont. %	Cont. M.H.	Total
Electrical - High Voltage														
	Cables between WD1 and the 6.9 kV switchgear - Cable type A 1c-1000 kcmil, copper conductor, 15 kV XLPE Copper Wire shield power cable (type MV-90), 100% insulation level		76	Meter(s)	150 $	11,400 $	15	1,710 $	0.75	57	7,980 $	15	1,197 $	22,287 $
	Cables between WD2 and the 6.9 kV switchgear - Cable type A 1c-1000 kcmil, copper conductor, 15 kV XLPE Copper Wire shield power cable (type MV-90), 100% insulation level		140	Meter(s)	150 $	21,000 $	15	3,150 $	0.75	105	14,700 $	15	2,205 $	41,055 $
	Connectors for Cables between WD1 and the 6.9 kV switchgear - Cable type A 1c-1000 kcmil, copper conductor, 15 kV XLPE Copper Wire shield power cable (type MV-90), 100% insulation level		12	Unit(s)	750 $	9,000 $	15	1,350 $	9.00	108	15,120 $	15	2,268 $	27,738 $
	Stress Cones for Cables between WD1 and the 6.9 kV switchgear - Cable type A 1c-1000 kcmil, copper conductor, 15 kV XLPE Copper Wire shield power cable (type MV-90), 100% insulation level		12	Unit(s)	95 $	1,140 $	15	171 $	3.00	36	5,040 $	15	756 $	7,107 $
	Switchgear 6.9 KV		1	Unit(s)	571,000 $	571,000 $	10	57,100 $	355.00	355	49,700 $	15	7,455 $	685,255 $
				Total subsection		613,540 $		63,481 $		661	92,540 $		13,881 $	783,442 $
				Total section		613,540 $		63,481 $		661	92,540 $		13,881 $	783,442 $
Commissioning and Start-Up														
	Commissioning manager (10 days per machine) - Included with Generator Supply		2	Unit(s)	0 $	0 $	0	0 $	0.00	0	0 $	0	0 $	0 $
	Commissioning Operational Verification - Contractor		2	Unit(s)	0 $	0 $	0	0 $	100.00	200	40,000 $	40	16,000 $	56,000 $
	Commissioning Operational Verification - Professional Services		2	Unit(s)	4,000 $	8,000 $	45	3,600 $	200.00	400	80,000 $	40	32,000 $	123,600 $
	Commissioning Pre-Operational Verification - Contractor		2	Unit(s)	0 $	0 $	0	0 $	200.00	400	80,000 $	40	32,000 $	112,000 $
	Commissioning Pre-Operational Verification - Professional Services		2	Unit(s)	6,000 $	12,000 $	45	5,400 $	300.00	600	120,000 $	40	48,000 $	185,400 $
				Total subsection		20,000 $		9,000 $		1,600	320,000 $		128,000 $	477,000 $
				Total section		20,000 $		9,000 $		1,600	320,000 $		128,000 $	477,000 $

Item	Description	Package #	Qty	Unit	Unit Price	Total Material	Cont. %	Cont. Mat.	M.H. Unit	M.H. Total	Total M.H.	Cont. %	Cont. M.H.	Total
Professional Services														
A-Engineering														
	Engineering		1	Lot	0 $	0 $	0	0 $	15,880.00	15,880	2,143,800 $	18	385,884 $	2,529,684 $
				Total subsection		0 $		0 $		15,880	2,143,800 $		385,884 $	2,529,684 $
B-Procurement														
	Freight & Logistics		1	Lot	0 $	0 $	0	0 $	500.00	500	67,500 $	40	27,000 $	94,500 $
	Procurement		1	Lot	0 $	0 $	0	0 $	500.00	500	67,500 $	40	27,000 $	94,500 $
				Total subsection		0 $		0 $		1,000	135,000 $		54,000 $	189,000 $
C-Construction Management														
	Construction Management		1	Lot	0 $	0 $	0	0 $	6,390.00	6,390	1,022,400 $	18	184,032 $	1,206,432 $
				Total subsection		0 $		0 $		6,390	1,022,400 $		184,032 $	1,206,432 $
D-Expenses														
	Construction Management Expenses		1	Lot	180,000 $	180,000 $	40	72,000 $	0.00	0	0 $	0	0 $	252,000 $
	Professional Expenses		1	Lot	100,000 $	100,000 $	40	40,000 $	0.00	0	0 $	0	0 $	140,000 $
				Total subsection		280,000 $		112,000 $		0	0 $		0 $	392,000 $
				Total section		280,000 $		112,000 $		23,270	3,301,200 $		623,916 $	4,317,116 $

Item	Description	Package #	Qty	Unit	Unit Price	Total Material	Cont. %	Cont. Mat.	M.H. Unit	M.H. Total	Total M.H.	Cont. %	Cont. M.H.	Total
Owners Cost														
A-Financing														
	Financing during construction period up to start-up date (4.24% per annum)		1	Lot	480,000 $	480,000 $	18	86,400 $	0.00	0	0 $	0	0 $	566,400 $
				Total subsection		480,000 $		86,400 $		0	0 $		0 $	566,400 $
B-Studies														
	Cost of previous and current studies (i.e.geotechnical, environmental preliminary eng.)		1	Lot	0 $	0 $	0	0 $	2,000.00	2,000	320,000 $	18	57,600 $	377,600 $
				Total subsection		0 $		0 $		2,000	320,000 $		57,600 $	377,600 $
C-Management														
	Salary and benefits of owner's project team personnel (including safety inspector), includes off-site expenses.		1	Lot	70,000 $	70,000 $	18	12,600 $	11,440.00	11,440	800,800 $	18	144,144 $	1,027,544 $
				Total subsection		70,000 $		12,600 $		11,440	800,800 $		144,144 $	1,027,544 $
D-Commissioning & Decommissioning														
	Commissioning & Mirrlees Shutdown (Staff labour and expenses, no fuel)		1	Lot	0 $	0 $	0	0 $	2,860.00	2,860	200,200 $	18	36,036 $	236,236 $
				Total subsection		0 $		0 $		2,860	200,200 $		36,036 $	236,236 $
E-Training														
	Training costs of plant personnel		1	Lot	0 $	0 $	0	0 $	429.00	429	30,030 $	18	5,405 $	35,435 $
				Total subsection		0 $		0 $		429	30,030 $		5,405 $	35,435 $
F-Permits														
	Construction and environmental permits (YESAB assigned to LNG project)		1	Lot	5,000 $	5,000 $	18	900 $	0.00	0	0 $	0	0 $	5,900 $
				Total subsection		5,000 $		900 $		0	0 $		0 $	5,900 $
G-Insurance														
	Blanket and third party insurance coverage - Project is covered under current policy		1	Lot	0 $	0 $	0	0 $	0.00	0	0 $	0	0 $	0 $
				Total subsection		0 $		0 $		0	0 $		0 $	0 $

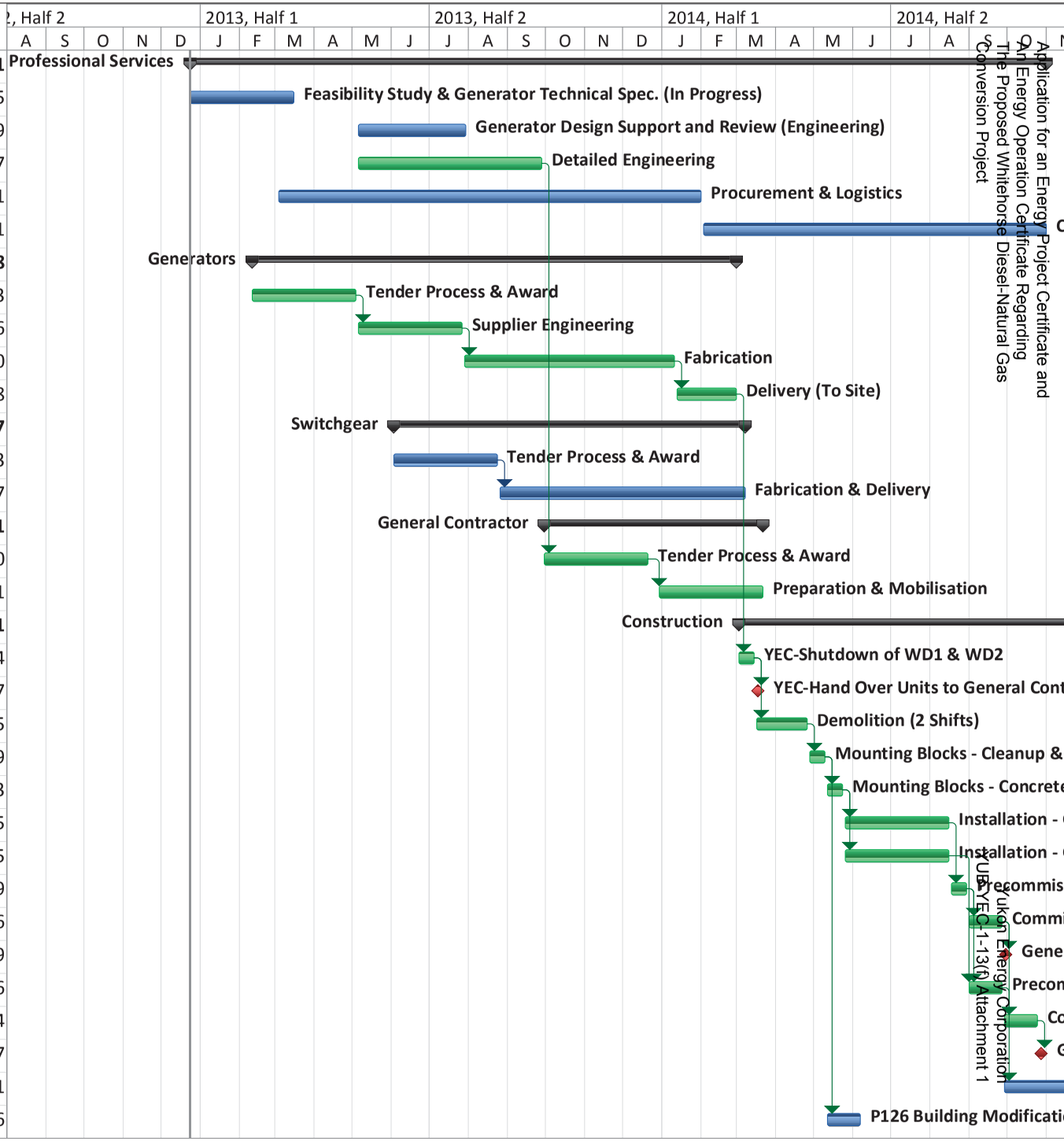
Item	Description	Package #	Qty	Unit	Unit Price	Total Material	Cont. %	Cont. Mat.	M.H. Unit	M.H. Total	Total M.H.	Cont. %	Cont. M.H.	Total
Owners Cost														
H-Escalation														
	Escalation cost (2%)		1	Lot	348,000 $	348,000 $	18	62,640 $	0.00	0	0 $	0	0 $	410,640 $
		Total subsection				348,000 $		62,640 $		0	0 $		0 $	410,640 $
I-Public Relations & Legal														
	Public Relations, Legal Costs		1	Lot	100,000 $	100,000 $	18	18,000 $	0.00	0	0 $	0	0 $	118,000 $
		Total subsection				100,000 $		18,000 $		0	0 $		0 $	118,000 $
		Total section				1,003,000 $		180,540 $		16,729	1,351,030 $		243,185 $	2,777,755 $
Freight														
	Handling - Vancouver airport (generators)		4	Unit(s)	17,500 $	70,000 $	20	14,000 $	0.00	0	0 $	0	0 $	84,000 $
	Handling - Whitehorse airport (generators)		4	Unit(s)	7,500 $	30,000 $	20	6,000 $	0.00	0	0 $	0	0 $	36,000 $
	Transport - Barge From Vancouver to Skagway (auxiliary equipment)		2	Lot	166,715 $	333,430 $	20	66,686 $	0.00	0	0 $	0	0 $	400,116 $
	Transport - From Generator Supplier to Vancouver (included)		1	Lot	0 $	0 $	0	0 $	0.00	0	0 $	0	0 $	0 $
	Transport - From Vancouver airport to Whitehorse airport-Engine and Frame Shipped Separately		4	Unit(s)	500,000 $	2,000,000 $	20	400,000 $	0.00	0	0 $	0	0 $	2,400,000 $
	Transport and disposal off site of the (2) Mirrlees generators		1	Lot	240,000 $	240,000 $	20	48,000 $	0.00	0	0 $	0	0 $	288,000 $
	Transport of equipment & material trucked from Skagway to YEC		40	Lot	1,500 $	60,000 $	20	12,000 $	0.00	0	0 $	0	0 $	72,000 $
		Total subsection				2,733,430 $		546,686 $		0	0 $		0 $	3,280,116 $
		Total section				2,733,430 $		546,686 $		0	0 $		0 $	3,280,116 $
Spare Parts and First Fill														
	Commissioning spare parts (3% of material of one machine) and first fill of lubricating oil and glycol. Diesel fuel and natural gas for start-up are not included.		1	Lot	210,000 $	210,000 $	20	42,000 $	0.00	0	0 $	0	0 $	252,000 $
		Total subsection				210,000 $		42,000 $		0	0 $		0 $	252,000 $
		Total section				210,000 $		42,000 $		0	0 $		0 $	252,000 $

Item	Description	Package #	Qty	Unit	Unit Price	Total Material	Cont. %	Cont. Mat.	M.H. Unit	M.H. Total	Total M.H.	Cont. %	Cont. M.H.	Total
	Grand Total					17,286,082 $		2,952,843 $		64,475	8,473,139 $		1,678,517 $	30,390,582 $

Appendix H

Preliminary Schedule

	Start	Finish
	Mon 12-12-24	**Fri 14-10-31**
enerator Technical Spec. (In Progress)	Mon 12-12-24	Fri 13-03-15
pport and Review (Engineering)	Mon 13-05-06	Mon 13-07-29
s	Mon 13-05-06	Fri 13-09-27
stics	Mon 13-03-04	Fri 14-01-31
ement	Mon 14-02-03	Fri 14-10-31
	Mon 13-02-11	**Fri 14-02-28**
ward	Mon 13-02-11	Fri 13-05-03
	Mon 13-05-06	Fri 13-07-26
	Mon 13-07-29	Fri 14-01-10
	Mon 14-01-13	Fri 14-02-28
	Mon 13-06-03	**Fri 14-03-07**
ward	Mon 13-06-03	Fri 13-08-23
ry	Mon 13-08-26	Fri 14-03-07
	Mon 13-09-30	**Fri 14-03-21**
ward	Mon 13-09-30	Fri 13-12-20
isation	Mon 13-12-30	Fri 14-03-21
	Mon 14-03-03	**Fri 14-11-21**
D1 & WD2	Mon 14-03-03	Fri 14-03-14
s to General Contractor	Mon 14-03-17	Mon 14-03-17
	Mon 14-03-17	Fri 14-04-25
eanup & Concrete	Mon 14-04-28	Fri 14-05-09
oncrete Curing	Mon 14-05-12	Fri 14-05-23
tor No. 1	Mon 14-05-26	Fri 14-08-15
tor No. 2	Mon 14-05-26	Fri 14-08-15
Generator No. 1 (2 Shifts)	Mon 14-08-18	Fri 14-08-29
nerator No. 1	Mon 14-09-01	Fri 14-09-26
rational	Mon 14-09-29	Mon 14-09-29
Generator No. 2	Mon 14-09-01	Fri 14-09-26
nerator No. 2	Mon 14-09-29	Fri 14-10-24
rational	Mon 14-10-27	Mon 14-10-27
Warranty)	Mon 14-09-29	Fri 14-11-21
ications	Mon 14-05-12	Fri 14-06-06



Appendix I

P126 Building Modification References

1. REVIEW OF NBCC 2010 REQUIREMENTS

As described in the P126 Building Modifications section of the report, verification of the structural conformance of the building to NBCC 2010 requirements is part of this study. Specifically, Part-4, Commentary L is the section of the code which pertains to the approach to be used for existing buildings and was the reference document used to establish the basis of BBA's approach for analyses and recommendations for upgrade of the building.

Commentary L supplies guidelines and recommendations for the evaluation of existing buildings for which there has been no change in use or occupancy, or alterations to the building's structure. Discounting the slight modifications observed during the site structural audit (missing bracings), this is the case for the P126 building.

The P126 building was constructed during three (3) different periods: 1968, 1974 and 1991. As defined in Commentary L, the benchmark versions of building code are 1960 for snow and wind loads and 1970 for seismic loads. By definition, benchmark versions define the earliest version that satisfies the life-safety intent of the current 2010 code, if there is no change in use or occupancy.

It can be assumed that the original buildings were designed in compliance with the latest codes of the times, i.e., the 1965 code for the original 1968 portion, the 1970 code for the 1974 portion and the 1990 code for the 1991 addition. If this assumption is correct, then this implies that all portions of the existing building need not be reviewed for 2010 snow and wind loads, and only the 1968 portion of the building needs be reviewed for 2010 seismic compliance.

Paragraph 16 of Commentary L states that buildings designed and built in accordance with previous codes may be considered acceptable, provided that the previous code satisfies the life-safety requirements of the current code and provided that the building, or its use is not altered in such a way as to affect its structural behaviour or increase the loading on the structure.

BBA interprets this to mean that, at the very least, snow and wind design loads from the original 1965, 1970 and 1990 codes can be used in the analyses models, rather than

today's 2010 loads, as these loads should, by virtue of their benchmark years, be acceptable.

This is confirmed by Table L-1, where it is indicated that the original loads used when the building was designed can be maintained, but the NBCC recommends that the 2010 load factors be applied. This is the approach that was adopted by BBA for the structural analyses of the "as-built and reinforced" building.

Commentary L also defines the reliability level of a structure, which combines the system's behavior, the risk level associated with collapse and the building's past performance. Although BBA's interpretation of the reliability level for the P126 building would allow for reductions in load factors, Commentary L does not allow for reductions or any other exemptions for "post-disaster" buildings, regardless of the year of construction.

2. STRUCTURAL ANALYSES

2.1 General

For all three (3) portions of the building, the superstructure consists of a "pre-engineered" building, of similar geometry and construction. Rigid, steel portal frames are provided at each grid line and support cold-rolled purlin and girt sections. From observations on site and review of the original drawings, some wall bays have intermediate girts supporting shorter wall panels, while other bays have no girts and the cladding panels span the complete height of the building.

2.2 Review of 1968 Building

Since the 1968 portion was the most probable portion to cause problems with regards to 2010 seismic requirements, it was decided to first analyze the original design, as per the 1965 building code, in order to establish code compliance and structural integrity. Also, as noted in the report, it had been observed during the site structural audit that portions of the original bracing had either never been installed or been subsequently removed. Understanding the original design for the 1968 portion was considered essential in understanding the "as-built" performance of the combined building. No load factors were

applied for the original building analysis, as the design methods of the times used allowable stress design rather than ultimate limit states.

Results of the analysis of the original 1968 design can be seen in Figures 1 and 2. In Figure 1, it can be observed that all bracings are red, which can either designate non-compliance to code, or alternatively, that they are failing.

Bracing elements normally need to be designed so that their slenderness ratio, kl/r, is less than 300 for tension elements and less than 200 for compression elements. These conditions are the minimum required to avoid buckling and sagging. In the analysis model, the rods are so slender that the computer cannot recognize them as compression members and only allows them to work in tension, which is, in fact, how the members behave in reality. However, regardless of the fact that they are not conforming to design code due to slenderness effects, they are nonetheless able to resist the tension loads applied. This can be seen in Figure 2, where the rod elements were replaced by cables of equivalent diameter. This simulation was done because the design codes will recognize cable elements as being “tension only” structural members and will not designate them as failing due to slenderness requirements. The results show that the original building design is then conforming to 1965 design loads.

3. REVIEW OF COMBINED 1968, 1974 AND 1995 “AS-BUILT” BUILDING ANALYSIS

In the combined, “as-built” structural analysis, the original design loads were applied for wind, snow and seismic loads, except for the 1968 portion, where 2010 seismic loads were applied. NBCC 2010 load factors were applied for all loads, as recommended by Commentary L. In addition, bracings that were noted to be missing during the site audit were also excluded from the analysis. However, girts missing between grids V and VII were included in the model because they are critical for reducing the column un-braced lengths, and are included as additional works to be done for reinforcing.

As can be seen in Figure 3, several columns and most bracings are indicated to be failing under the combination of dead, live and snow load. As mentioned previously, the NBC 2010 does not allow for load factor reductions, and the combination includes factors of 1.25 for dead, 0.5 for live and 1.5 for snow. Because the missing bracings are

causing torsion in the building, this induces failure in the some bracing and columns under ultimate load conditions.

Figure 4 shows the results of the same analysis when the rod bracings are replaced by cables. Although there are less bracings shown as failing, the same columns are red.

It is also important to note that the structural model also reveals that building deflections at the roof eave level (at the top of column VII) can be up to 2'' under the dead + wind load combination. This is much more than the recommended allowable deflection of L/500 or 0.6 in.

4. REVIEW OF REINFORCED BUILDING

Figure 5 shows the results of analysis of the reinforced, combined building.

Existing, 5/8'' rod bracing has been replaced by 7/8'' bracing, and additional bracing of the same size has been added in both the walls and roof in order to stabilize the structure and prevent it from twisting.

New bracings have been located, as much as possible, in such a way as to not interfere with existing mechanical installations or wall openings.

Figures 6 thru 9 show the reinforced roof plan and wall elevations. These also form the basis for estimating the work to be done in order to bring the building in conformance with the NBC 2010 requirements for a post-disaster building.

5. CONCLUSIONS

It is clear from the site audit that the P126 building has not shown any signs of distress or major deterioration, and if untouched, may continue to behave as it has for the past 60 years, depending on actual snow, wind and seismic loads applied.

However, as it stands today, it theoretically cannot resist the ultimate loads required by the NBC 2010 code for post-disaster buildings.

On the positive side, the work required to bring the building up to code is relatively easy to achieve and at a reasonably low cost.

FIGURE 1

1968-CODE - MODEL A36 - With Rod Bracings + With Girts as Designed

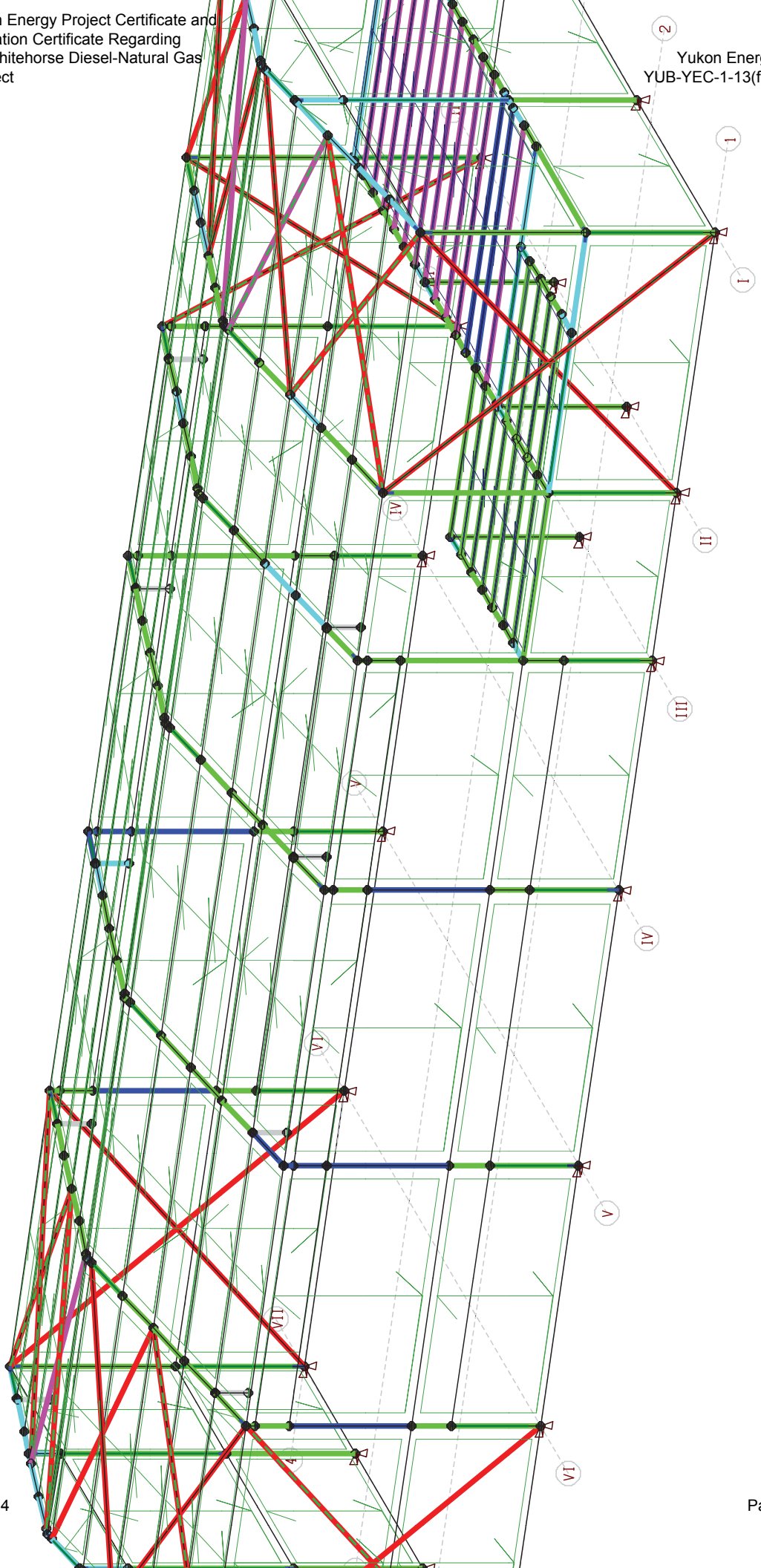


Figure 1 - Original 1968 Design - Rod Bracings

FIGURE 2

1968 - CODE- MODEL A36 - With Cable Bracings + With Girts

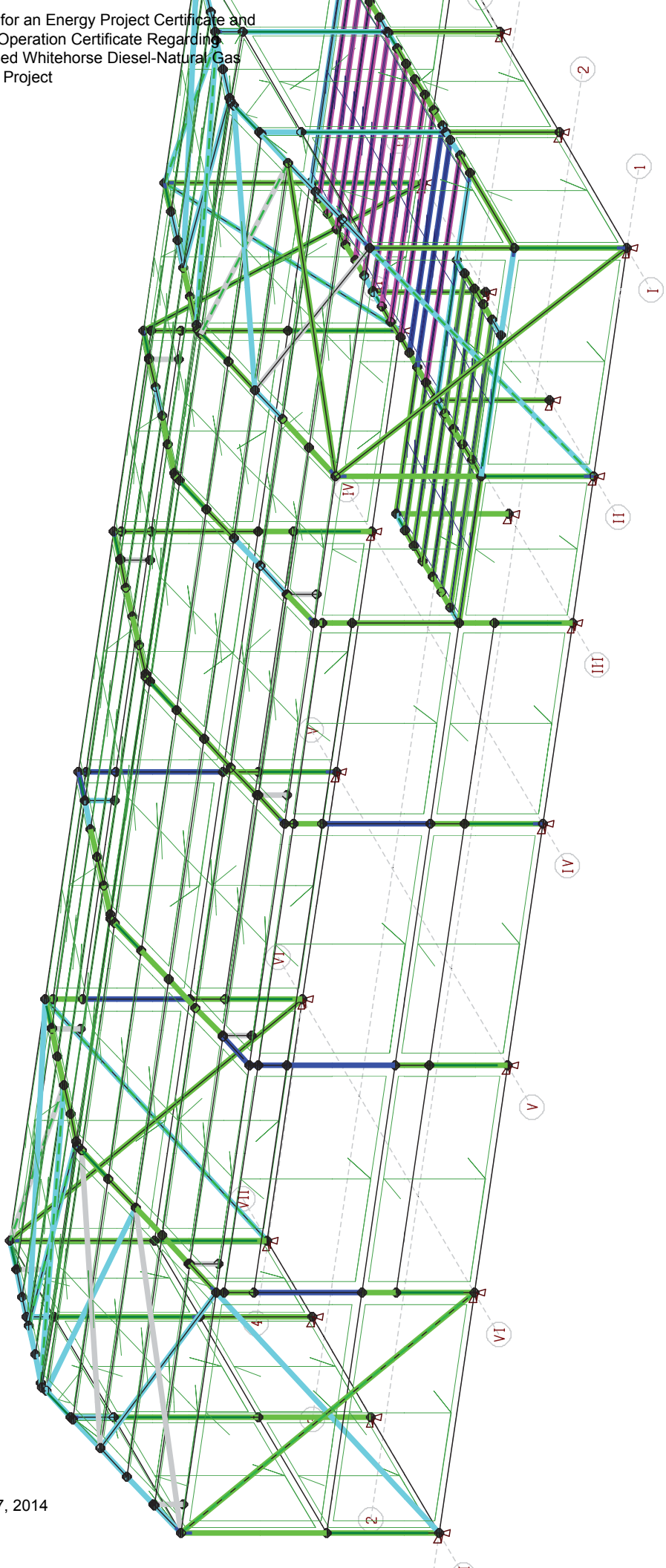


Figure 2 - 1968 Original Design with Cable Bracing

FIGURE 3

2010-CODE – MODEL A36 -a-A572-With Rod Bracings +With Girts At River Side

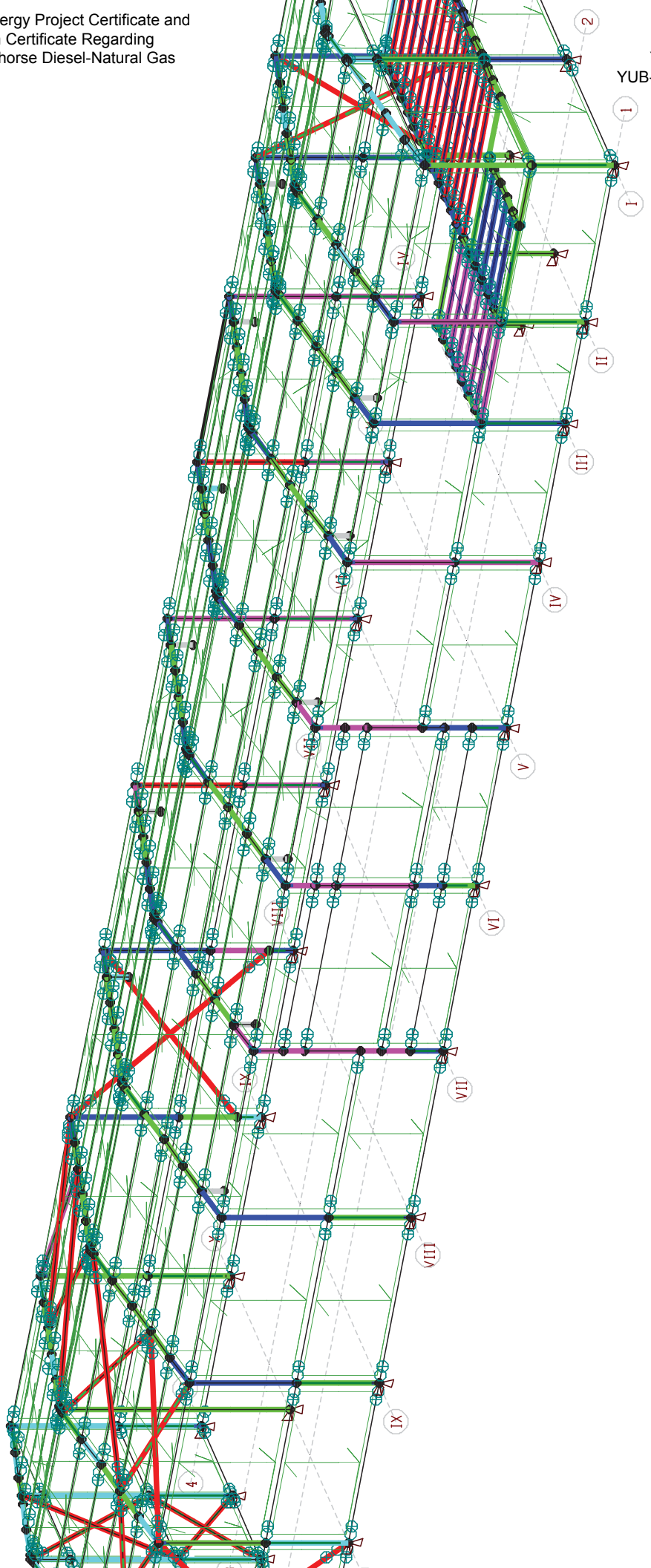


Figure 3 - Combined, "As-built" model - Rod Bracing

FIGURE 4

2010-CODE – MODEL A36-a- A572- With Cable Bracings + With Girts at River Side

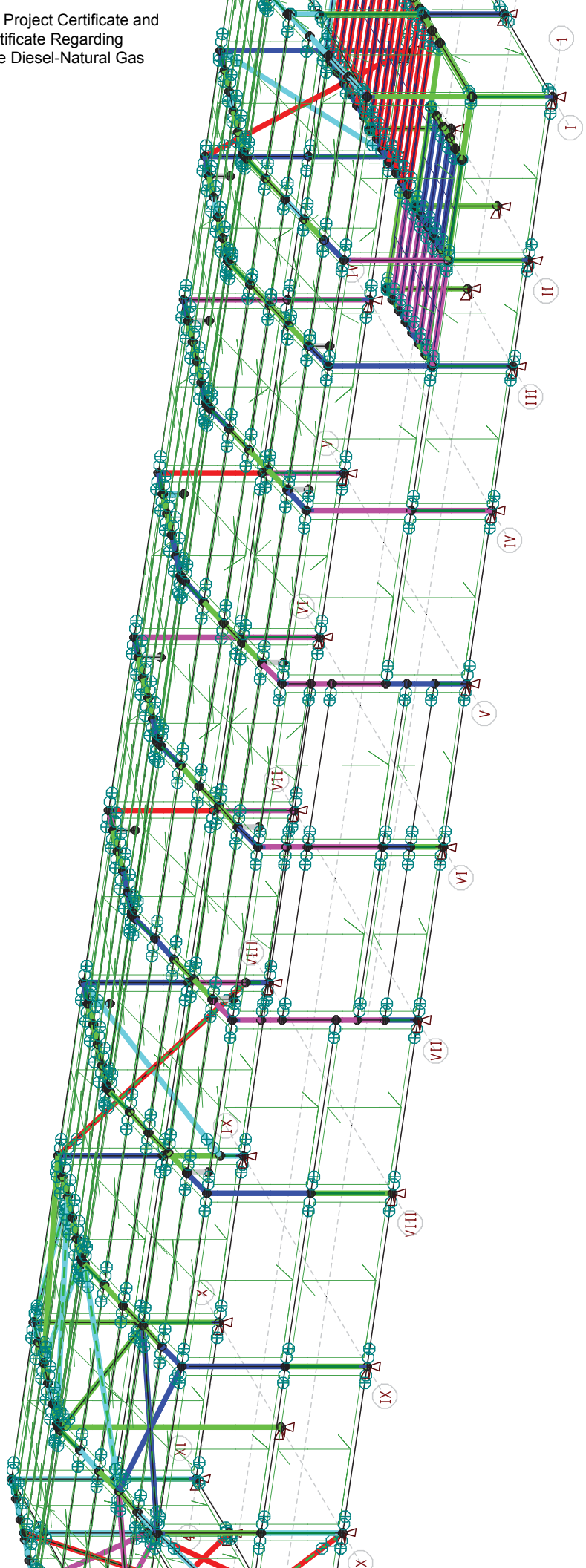


Figure 4 - Combined, "As-built" Model - Cable Bracing

FIGURE 5

2010-CODE - MODELA36 -a-A572 - With Cable Bracings +With Girts at Both Sides-Reinforced

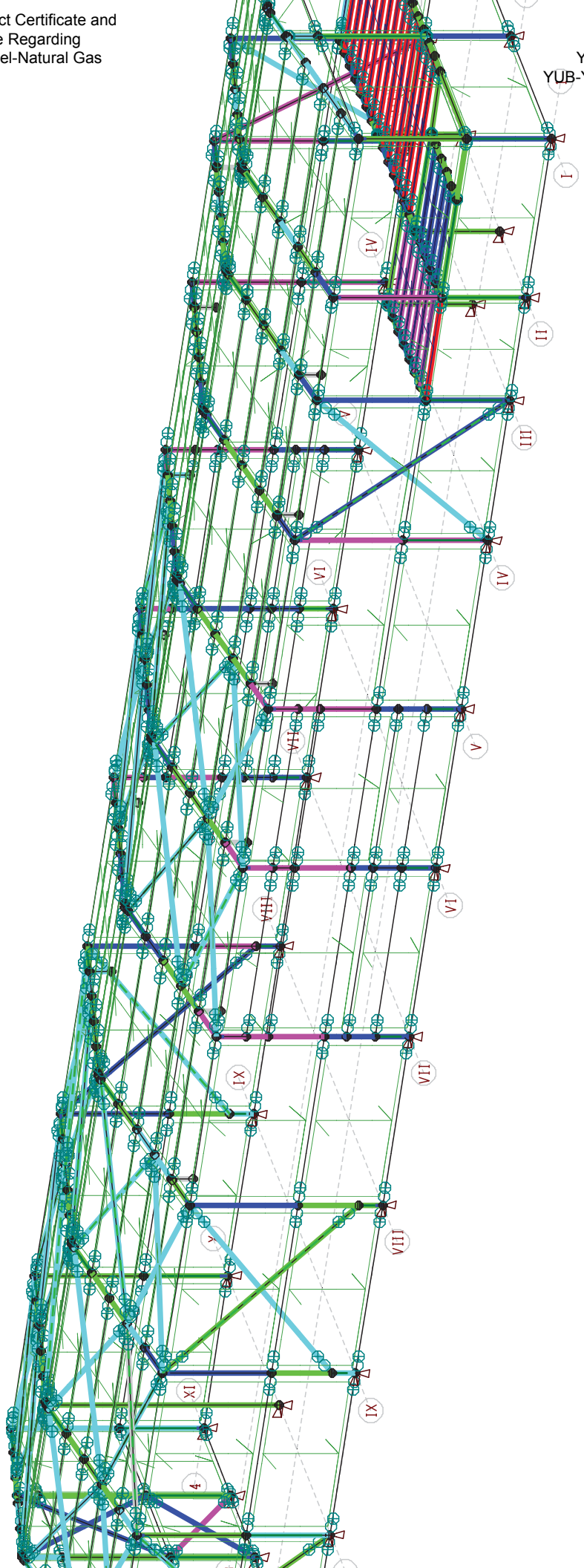


Figure 5 - Combined Building - Reinforced

FIGURES 6 to 9

Building Reinforcement

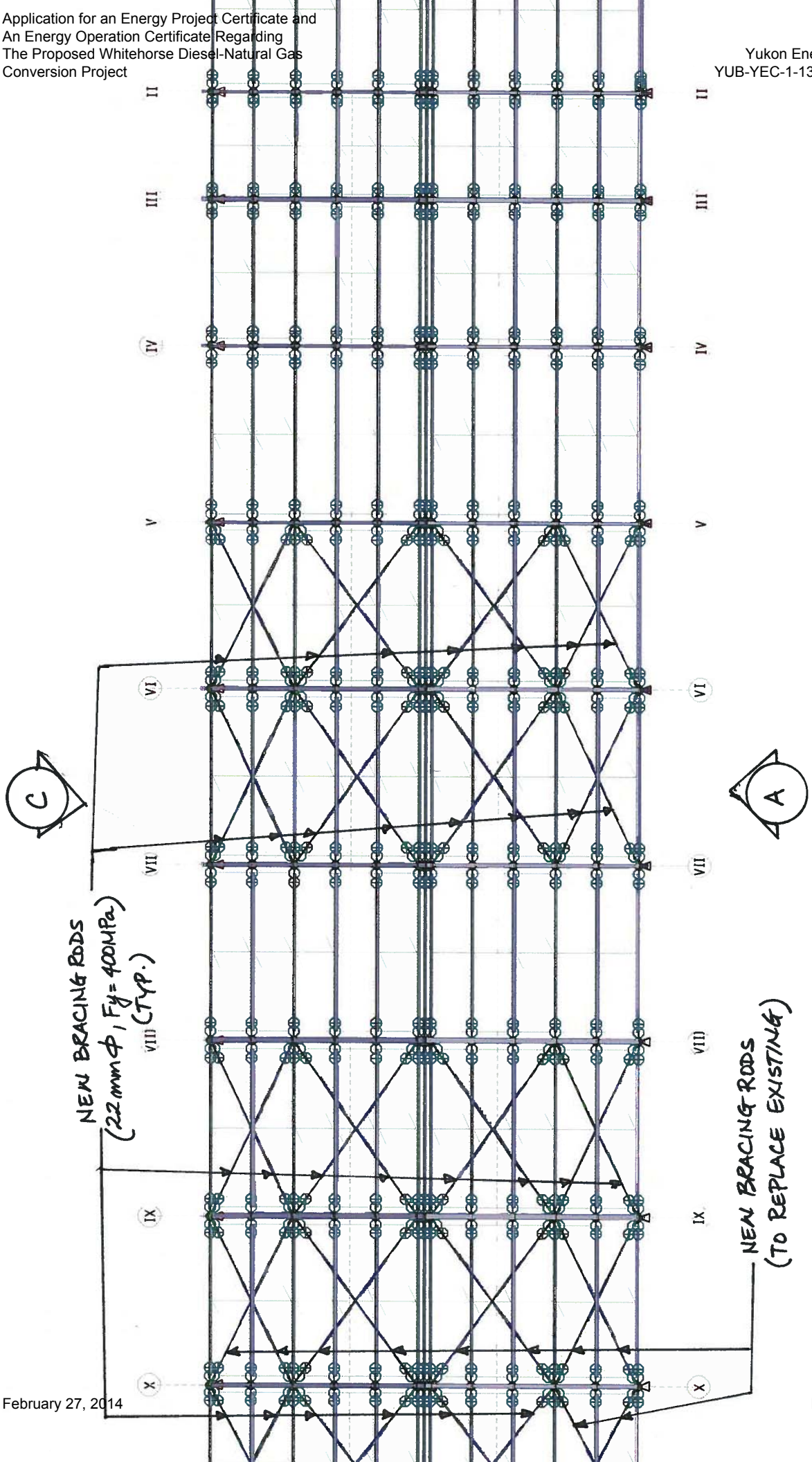


Figure 6 - Roof Plan Reinforcement

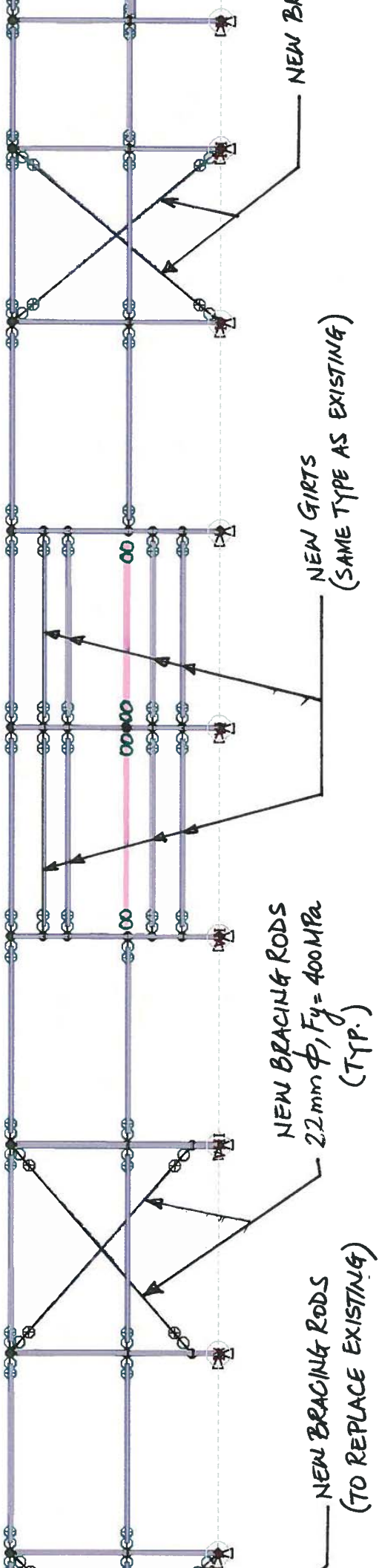
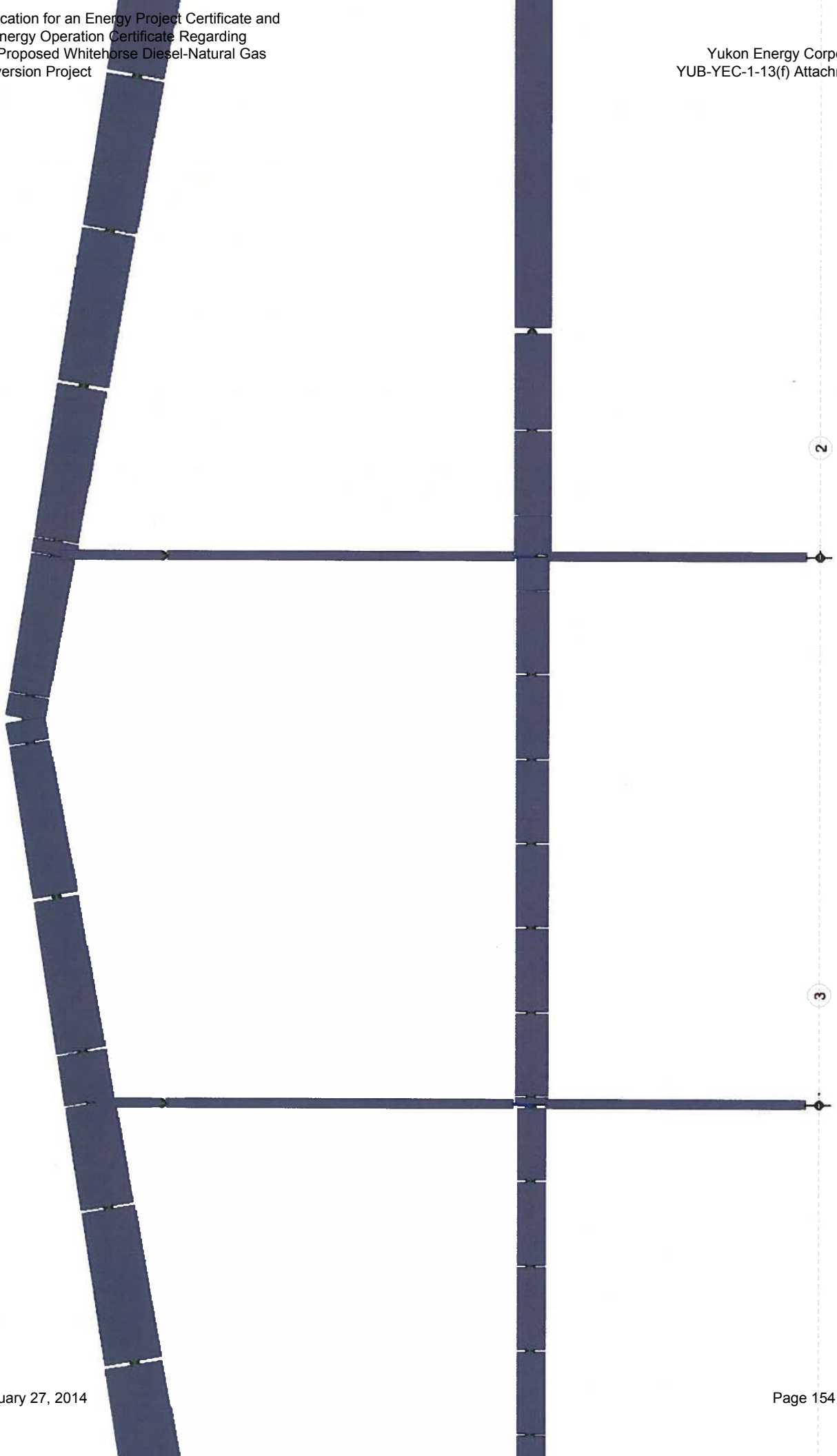


Figure 7 - East Wall Reinforcement


2
3
VIEW B

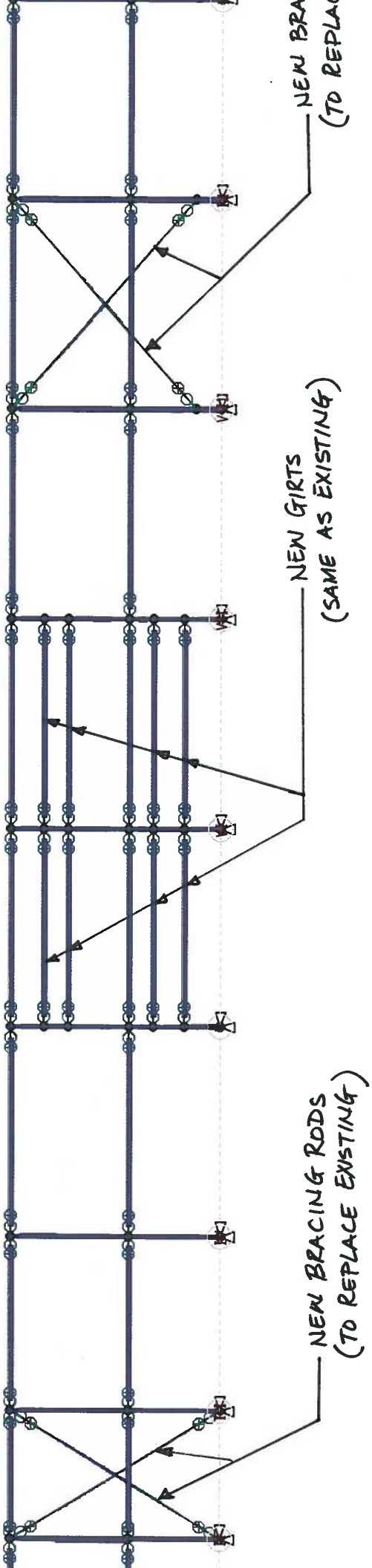


Figure 8 - West Wall Reinforcement

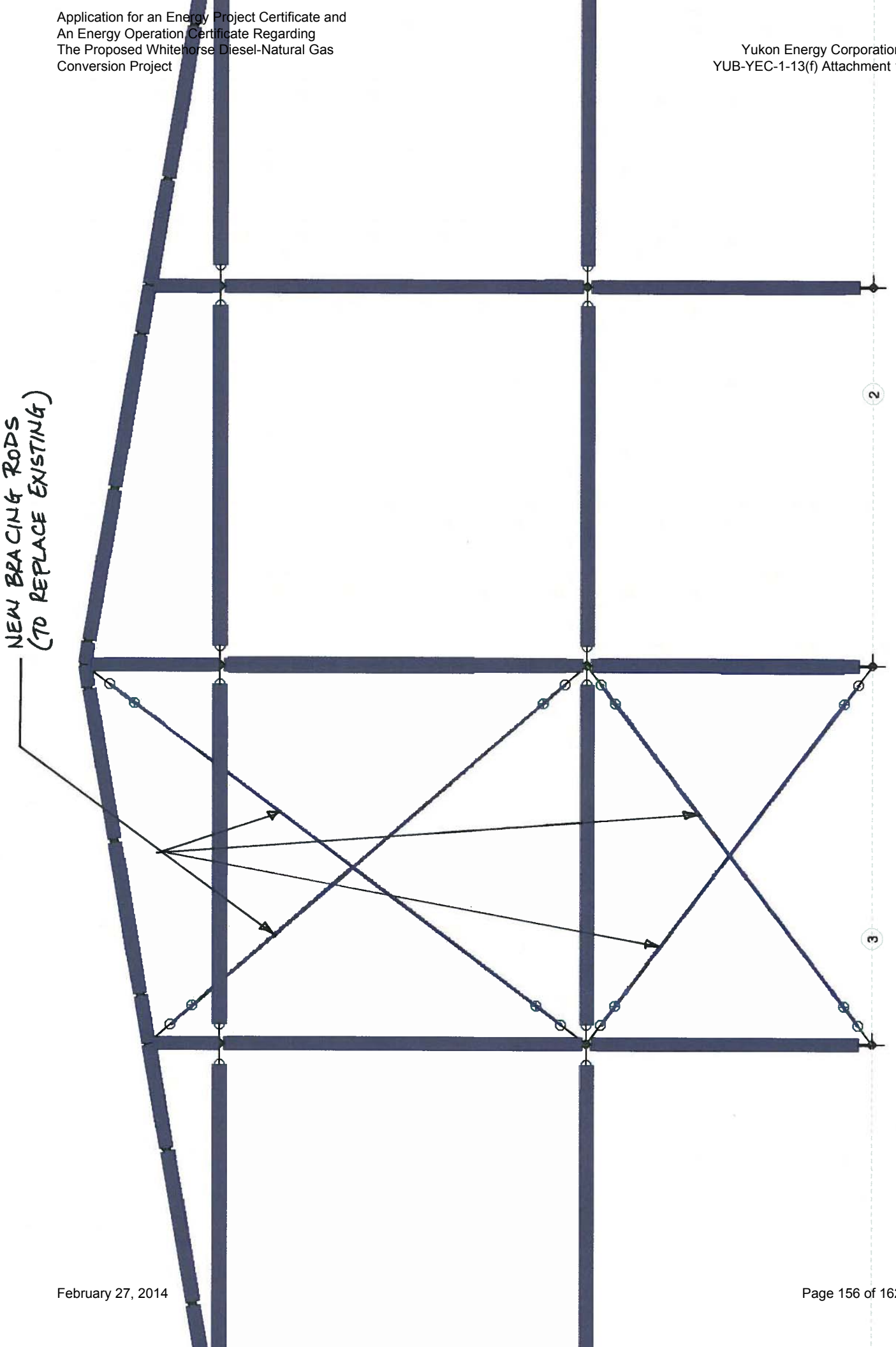


Figure 9 - South Wall Reinforcement

Appendix J

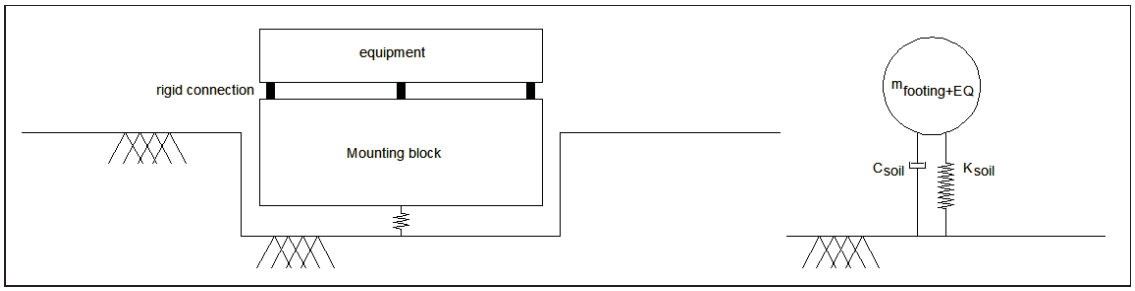
Mounting Block References

Mounting Blocks

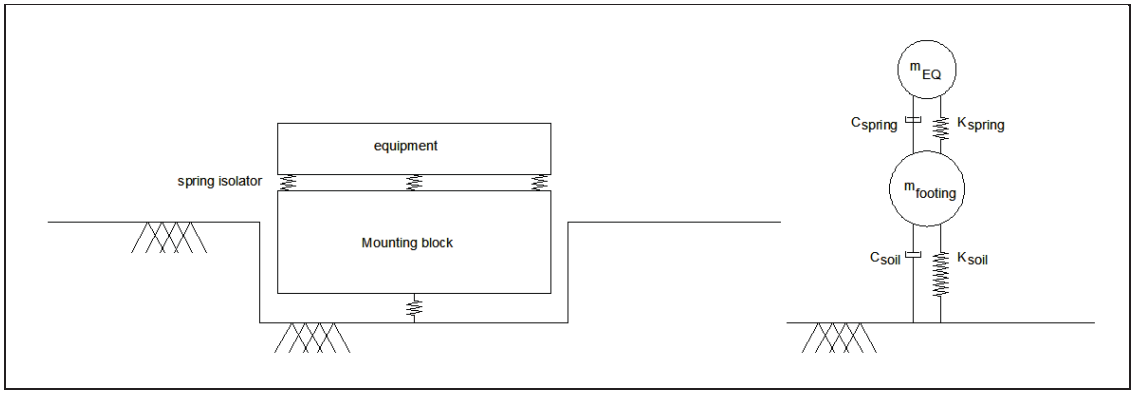
As part of this study, the following activities were completed for the mounting blocks:

- Preparation of geotechnical scope of work and sketch of borehole locations in order to try to obtain better parameters of the underlying soil conditions in the vicinity of the existing WD1 and WD2 mounting blocks; review of the previous GEA report from 2006;
- Preparation of finite element models for each of the WD1 and WD2 mounting blocks, as the WD1 block is smaller than the WD2 block;
- Static, parametric and dynamic analyses of the behavior of mounting blocks before (with existing Mirrlees units) and with the new generators, using spring pack data supplied by Wärtsilä and assumptions on soil parameters. Detailed analyses models and results can be made available upon request;

Mirrlees Units – Single Degree of Freedom System



New Generator Units – Two Degree of Freedom System



As can be seen from the illustrations above, the addition of spring packs underneath the new units will create a system that has two (2) degrees of freedom: the first spring component is the geodynamic behavior of the underlying soil, while the second spring component is the spring packs themselves.

As indicated in the 2006 GEA report, clearer definition of the underlying soil parameters will be critical for precise evaluation of the mounting block behavior with the new units. With the information available today, assumptions need to be made on the ground conditions, and, for the moment, the assumptions made by GEA seem reasonable and will be used until better information is made available (shear modulus, G = 10 to 70 MPa, Poisson's ratio = 0.4). YEC has indicated that the geotechnical investigation and recommendations on soil properties will probably be undertaken in March, at which time an update of the finite element models can be made.

The second parameter that is critical for a reliable analysis is the spring constant and damping coefficient for the spring packs supplied with the new units. The data and recommendations for the "Vibratec T4425-117M" spring packs to be used with the new units were supplied by Wärtsilä.

Based on generator drawings provided by Wärtsilä, the existing mounting blocks (both WD1 and WD2) are of sufficient dimensions to support the new units. In developing the models, it has been assumed that larger cavities in the existing blocks would be filled with reinforced concrete and smaller cavities filled with a non-shrink grout, resulting in an increase in foundation weight of approximately 20%.

Combined with the additional weight of the new units, the total increase in static bearing pressure on the underlying soil is estimated at approximately 30% (from 63 to 81 kPa) for WD1 and 15% (from 68 to 78) for WD2. From a static point of view, this increase should not pose a problem if the sub-foundation soils were installed in accordance with good engineering practice and can withstand reasonable bearing pressures (100 kPa).

Dynamic analyses were performed for the existing Mirrlees units (for comparison bases with the GEA report assumptions), as well as on the new units, using the data provided for the spring packs and different values of soil parameters.

Analysis of the existing installation, considering the range of values assumed for the soil shear modulus, has indicated that the frequency of vertical vibrations for the SDOF system (equipment

and foundation rigidly connected) are in the range of 3.9 to 10.7 Hz, which is quite close to the Mirrlees operating frequency of 9 Hz. Theoretically, this means that resonant conditions could be attained during normal operations and could amplify any vibrations caused by the unit operations.

Analysis of the future installation with Wärtsilä units indicates that the 2-DOF system's first mode of vibration, for all soil types, (mounting block WD1) is at a frequency of 3.5 Hz and well separated from the machine operating frequency of 12 Hz. In normal operating conditions with spring packs operating correctly, the maximum vertical vibrations will be in the order of 0.34 mm/s (RMS), including pitching and rolling modes, while the combined horizontal and rocking vibrations will be approximately 1.59 mm/s (RMS). As can be seen in the ISO 2372 chart below, this classes the system performance in the "GOOD" range.

As mentioned above, it is of utmost importance that the spring packs be inspected and maintained on a regular basis to prevent spring hardening or blocking. Analyses were also performed to simulate poor functioning of the springs, such as a 50% increase in spring rate (spring hardening over time), as well as spring blockage. The results show a consistent increase in vibration values with these conditions, with a maximum value obtained of 6.8 mm/s for transversal rocking.

Vibration Severity		Velocity Range Limits and Machinery Classes ISO Standard 2372			
CMVP40 in/s eq. Peak	CMVP50 mm/s RMS	Small Machines	Medium Machines	Large Machines	
		Class I	Class II	Rigid Supports Class III	Flexible Supports Class IV
0.02	0.28	Normal - Vertical			
0.03	0.45		Good		
0.04	0.71				
0.06	1.12				
0.10	1.80	Normal - Horizontal	Satisfactory		
0.16	2.80				
0.25	4.50				
0.39	7.10	Spring Blocked - Transversal Rocking	Unsatisfactory		
0.62	11.20				
1.00	18.00		Unacceptable		
1.56	28.00				
2.50	45.00				
3.95	71.00				

Support classification according to ISO 2372

Flexible Support: The fundamental natural frequency of the machine/support system is lower than its main excitation frequency.

Rigid Support: The fundamental natural frequency of the machine/support system is higher than its main excitation frequency.

However, analysis of the system's second mode of vibration indicates that for some soil types, near-resonance conditions might be possible. For example, when a value of G=70 MPa is used in the analysis, vertical vibration is at a frequency of 13.4 Hz, which is close to the unit's operating frequency of 12 Hz. If a value of G=10 MPa is used, the same vertical vibration will be at 5.6 Hz, while the longitudinal rocking frequency will be at 11.1 Hz, also close to operating frequency. These results emphasize the importance of confirming the soil parameters in order to "tweak" the system for optimal behavior.

Mounting Block Conclusion

In conclusion, the analysis results for the mounting blocks indicate that, based on the soil assumptions and with properly functioning spring packs to ensure the target transmissibility levels required by the supplier, the new Wärtsilä units could be operated on the existing mounting blocks and should not prove to be problematic for vibrations. Some transient vibrations may occur during start-up and shut-down, due to the proximity of the second modes of vibration to the operating frequency. The addition of viscous dampers to the spring packs would help to reduce these effects, especially for the horizontal vibration components.

These analysis results could be confirmed during a later phase, once measured, in-situ soil parameters are made available.

Modifications to mounting blocks will only involve the filling of cavities with reinforced concrete or non-shrink grout to receive the new units.



TOPIC: **Higher-efficiency diesel engine replacement option**

REFERENCE: **Application, page 24 and page 26**

YECL proposed, in its recent GRA, a 2 MW new diesel engine on the grid at Carcross at a cost of $3 million.

For comparative purposes, an alternative has been examined assuming two new 6.7 MW diesel engines (13.4 MW), with the first unit installed in late 2014 at an estimated capital cost of $22.5 million … and the second unit installed in late 2015 at an estimated capital cost of $11.0 million ...

PREAMBLE:

The board requires further information.

QUESTION:

a) Can YEC explain why its estimate regarding the installation costs of two high-efficiency 6.7 MW diesel replacement units, the first at $22.5 million and the second at $11.0 million, are significantly greater than the 2 MW unit that YECL proposed, in its recent GRA, to install at Carcross for $3 million.
b) Footnote 38 refers to “40% efficiency”. How valid is that assumption in terms of the proposed new diesel units?
c) With respect to the new higher efficiency diesel option, please provide details regarding what the estimated $22.5 million capital cost, related to the installation of the first unit, is comprised of. Please provide a table similar to Table 3.1, which lists the detailed cost items, and also provide an explanation regarding each component item in the table.
d) Similar to question (a), please provide explanation regarding the component costs and a table listing the cost items that make up the $11.0 million capital cost related to the installation of the second unit.

ANSWER:

(a)

Yukon Energy can only speak to the installation costs it has prepared. We have no knowledge of the pricing or scope of work for the Carcross diesel units proposed by YECL. As explained in the Application, the YEC estimates for new diesel reflect preliminary engineering and costing completed in 2013 for installing new units that would have utilized the WD1 and WD2 service bays, and included consideration of balance of plant requirements as well as demolition costs to remove WD1 and WD2.

It is noted that the updated cost today of the first 6.7 MW unit is $21.5 M due to a reduction on the removal cost estimates of WD1 and WD2 as well as planning costs not directly required for new diesel installation in the WTGS (see YUB-YEC-1-1(d) and YUB-YEC-1-13(a) Updated Table 4-3).

(b)

Yukon Energy believes 40% represents a good average efficiency rate for both new diesels and natural gas engines. The engine manufacturer claim, in both cases, is an efficiency rate up to 44-46% but these are peak efficiencies at optimum loads and environmental conditions. For the purposes of project economics and fuel consumption, 40% efficiency was used as an average efficiency under a wide range of loads and environmental conditions for both new diesel and the Jenbacher natural gas engines.

(c)

Please see Table 1 below for a table listing cost items for the installation of the first new diesel unit in the WTGS WD1 or WD2 service bays. This estimated cost of $21.6 million for installing only one unit reflects the updated cost estimate for installation of the two units as reviewed in response to YEC-YEC-1-6(b), and an assessment that $11.1 million of the full development cost would be saved if only one unit was installed.

Table 1:
Estimated Capital Costs for One Diesel Engine Replacement at WTGS (2013 $Millions)

Activity	Estimated Costs ($million)	% Total Costs
Planning Costs	1.6	7%
Engineering Services	1.9	9%
Project Management	1.1	5%
Diesel Gen - Engines	8.6	40%
Grid Connection	0.6	3%
Owners Costs - Construction Phase	3.1	14%
BOP - Preliminary Assessment	0.3	1%
Balance of Plant work	4.4	20%
Total	21.6	100%

(d)

As reviewed below, there is no table detailing costs to install a second unit as a separate construction season work - and the $11.1 million estimate likely understates the costs that would be required.

As noted in response to (c) above, the $11.1 million estimate was provided to indicate that approximately $11.1 million of the full development cost for 13.4 MW of new diesel (i.e., the $32.7 million updated cost provided in YEC-YEC-1-6(b)) would be saved if only one unit was installed. Please see YECL-YEC-1-6(b) for a table setting out the detailed updated cost estimate of $32.7 million for 13.4 MW installation. No attempt has been made to estimate how much the $11.1 million cost would need to be increased to reflect the assumption that this work was not being undertaken as part of a one season construction package for completion at the same time as the first unit is installed. If the new diesel option had been pursued, YEC likely would have carried out the installation of both new units together in one construction season to secure cost efficiencies.

TOPIC: **GE pre-engineered J624 modular units**

REFERENCE: **Application, page 27, footnote 42**

Review of potentially available modular unit options indicated that GE is the only vendor currently offering such gas fired options in the scale relevant to Yukon Energy and with demonstrated cold climate northern operating experience.

PREAMBLE:

The Board requires further information.

QUESTION:

a) Please describe the process that YEC undertook to review/investigate the modular LNG generating unit options to choose from.

b) Please provide criteria that YEC made use of to inform its decision to choose the three J624 modular 4.4 MW units versus a larger size of unit.

c) Please provide a list of alternative modular units considered and reasons for not opting for that particular model of LNG unit.

d) What additional information can YEC provide that demonstrates these units are proven in cold climate northern operations? For instance, at which locations in northern climates are such units located, in what quantities (unit numbers and total MW at each location) and for how long have these units been operating on LNG? What problems have been encountered in their operations and what additional costs have be incurred in their operation?

e) What investigation did YEC undertake to ensure these units are suitable for use in northern climate operations and that no unknown problems or additional costs would be encountered in their installation and operation?

ANSWER:

(a)

Subsequent to the RFI process used to assess the larger dual and single fuel engines in the diesel powerhouse a review of modular generating units was undertaken by Yukon engine in the 3-5 MW range. This size range was selected based on a review of the loss of efficiency of the larger engines at less than full loads and recommendations from engine suppliers to run the engines at 50% or greater loads which did not fit the load profile for backup generators. Please see response to YCS/LE-YEC-1-5(a, b, d, e, and f) for review of RFI process and conclusions leading to consideration of modular unit options.

In addition to information initially provided by GE confirming the availability of the 4.375 MW modular gas-fired reciprocating engine option, information was obtained from Wartsila, MAN, Cummings and Caterpillar. Wartsila did offer a modular gas cube modular design powerhouse in Europe but it did not offer the product in North America nor did they recommend the product in cold climates. MAN was not able to offer a specific modular package to Yukon Energy. Cummings and Caterpillar were only able to offer modular package based on smaller units less than 2 MW's which were not suitable for YEC as they were too small.

(b)

Please see response to YUB-YEC-1-15(a).

(c)

Please see response to YUB-YEC-1-15(a).

(d) and **(e)**

The ability to perform in cold climate conditions was a major consideration for Yukon Energy. Yukon Energy confirmed that there are two Jenbacher installations in Russia with ambient conditions similar or colder than Whitehorse. The temperature conditions of the two locations are shown in the tables below along with a photograph of the project 1 plant in Siberia, Russia.

Yukon Energy discussed cold climate operation with representatives from Gas Drive and GE in Europe that had supplied and installed the Russia engines. They confirmed these installations were recent as they had only been putting the 6 series Jenbacher in modules for a couple of years. As part of the contract discussions some design changes were made to reflect the backup operation of these engines (they may be off for extended periods of time) hence needed additional insulation and heat from other sources to keep them warm when they are not running. The cost of the additional heating equipment was $37,000 and the cost of the additional module insulation was $32,000.

Table 1:
Russian project 1 Yamalo-Nenets Autonomous Okrug (8xJ620):

Climate data for Salekhard [hide]													
Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
Record high °C (°F)	3.5 (38.3)	1.9 (35.4)	5.7 (42.3)	15.5 (59.9)	24.5 (76.1)	31.6 (88.9)	32.9 (91.2)	29.9 (85.8)	24.8 (76.6)	18.2 (64.8)	7.0 (44.6)	4.1 (39.4)	32.9 (91.2)
Average high °C (°F)	−18.8 (−1.8)	−18.5 (−1.3)	−9.9 (14.2)	−4 (25)	3.7 (38.7)	14.3 (57.7)	19.7 (67.5)	15.7 (60.3)	8.8 (47.8)	−0.2 (31.6)	−11.3 (11.7)	−16.2 (2.8)	−1.39 (29.52)
Daily mean °C (°F)	−23.2 (−9.8)	−22.9 (−9.2)	−14.9 (5.2)	−9.1 (15.6)	−0.5 (31.1)	9.5 (49.1)	14.8 (58.6)	11.4 (52.5)	5.3 (41.5)	−3.0 (26.6)	−15.3 (4.5)	−20.7 (−5.3)	−5.72 (21.7)
Average low °C (°F)	−27.8 (−18)	−27.4 (−17.3)	−19.9 (−3.8)	−14 (7)	−4.2 (24.4)	5.2 (41.4)	10.0 (50)	7.3 (45.1)	2.2 (36)	−6 (21)	−19.5 (−3.1)	−25.2 (−13.4)	−9.94 (14.11)
Record low °C (°F)	−51.3 (−60.3)	−53.7 (−64.7)	−47.4 (−53.3)	−38.7 (−37.7)	−30.8 (−23.4)	−11 (12)	−1 (30)	−5.5 (22.1)	−9.6 (14.7)	−35.7 (−32.3)	−47.1 (−52.8)	−51.5 (−60.7)	−53.7 (−64.7)
Precipitation mm (inches)	23 (0.91)	19 (0.75)	21 (0.83)	26 (1.02)	37 (1.46)	51 (2.01)	65 (2.56)	69 (2.72)	42 (1.65)	46 (1.81)	28 (1.1)	27 (1.06)	454 (17.88)
Avg. rainy days	0.1	0	0.5	3	10	17	18	21	20	9	1	0	99.6
Avg. snowy days	26	23	23	16	13	2	0	0	3	17	24	27	174
% humidity	83	82	81	78	77	70	72	79	82	86	85	83	79.8
Mean monthly sunshine hours	4.0	48.0	135.0	209.0	233.0	270.0	307.0	185.0	96.0	57.0	18.0	0.0	1,562
Source #1: Pogoda.ru.net[11]													
Source #2: NOAA (sun only, 1961-1990)[12]													

Table 2:

Russian project 2 Moscow (4xJ620):

Climate data for Moscow (VVC) normals 1981–2010, records 1879 – the present [hide]													
Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
Record high °C (°F)	8.6 (47.5)	8.3 (46.9)	17.5 (63.5)	28.9 (84)	33.2 (91.8)	34.9 (94.8)	38.2 (100.8)	37.3 (99.1)	32.3 (90.1)	24.0 (75.2)	14.5 (58.1)	9.6 (49.3)	38.2 (100.8)
Average high °C (°F)	−4 (25)	−3.7 (25.3)	2.6 (36.7)	11.3 (52.3)	18.6 (65.5)	22.0 (71.6)	24.3 (75.7)	21.9 (71.4)	15.7 (60.3)	8.7 (47.7)	0.9 (33.6)	−3 (27)	9.6 (49.3)
Daily mean °C (°F)	−6.5 (20.3)	−6.7 (19.9)	−1 (30)	6.7 (44.1)	13.2 (55.8)	17.0 (62.6)	19.2 (66.6)	17.0 (62.6)	11.3 (52.3)	5.6 (42.1)	−1.2 (29.8)	−5.2 (22.6)	5.8 (42.4)
Average low °C (°F)	−9.1 (15.6)	−9.8 (14.4)	−4.4 (24.1)	2.2 (36)	7.7 (45.9)	12.1 (53.8)	14.4 (57.9)	12.5 (54.5)	7.4 (45.3)	2.7 (36.9)	−3.3 (26.1)	−7.6 (18.3)	2.1 (35.8)
Record low °C (°F)	−42.2 (−44)	−38.2 (−36.8)	−32.4 (−26.3)	−21 (−6)	−7.5 (18.5)	−2.3 (27.9)	1.3 (34.3)	−1.2 (29.8)	−8.5 (16.7)	−16.1 (3)	−32.8 (−27)	−38.8 (−37.8)	−42.2 (−44)
Precipitation mm (inches)	52 (2.05)	41 (1.61)	35 (1.38)	37 (1.46)	49 (1.93)	80 (3.15)	85 (3.35)	82 (3.23)	68 (2.68)	71 (2.8)	55 (2.17)	52 (2.05)	707 (27.86)
Avg. rainy days	0.8	0.7	3	9	13	14	15	15	15	12	6	2	105.5
Avg. snowy days	18	15	9	1	0.1	0	0	0	0.1	2	10	17	72.2
% humidity	83	80	74	67	64	70	74	77	81	81	84	85	76.7
Mean monthly sunshine hours	33	72	128	170	265	279	271	238	147	78	32	18	1,731
Source: [27] [28] [29][42]													

Photo of Yamalo-Nenets Autonomous Okrug (8xJ620 in Siberia, Russia)



TOPIC: **LNG fuel cost savings**

REFERENCE: **Application, page 11 and page 35**

Assuming 40% energy conversion efficiency at a minimum for the modular gas-fired engines, the initial low volume LNG haul cost to Whitehorse from Shell's Calgary facility (2,325 km) is estimated at 4.4 cents/kWh with A-Train units and 6.3 cents/kWh with Tridem units.

Table 4-5: Range of LNG Fuel Cost Savings Examined

LNG Fuel Cost Saving ($/kW.h)		
New Diesel LNG		LNG Saving
	A-Train from Calgary with 18% premium	
0.246	0.115 gas at $3.5/MMBTu, efficiency 44%	0.131
0.200	0.115 gas at $3.5/MMBTu, efficiency 44%	0.085
0.246	0.135 gas at $4.5/MMBTu, efficiency 40%	0.111
0.200	0.135 gas at $4.5/MMBTu, efficiency 40%	0.065
	Tridem from Calgary with 10% premium	
0.246	0.133 gas at $3.5/MMBTu, efficiency 44%	0.113
0.200	0.133 gas at $3.5/MMBTu, efficiency 44%	0.067
0.246	0.154 gas at $4.5/MMBTu, efficiency 40%	0.092
0.200	0.154 gas at $4.5/MMBTu, efficiency 40%	0.046

PREAMBLE:

Additional information regarding the impact of assumed efficiencies is needed.

QUESTION:

a) How valid is the 40% energy conversion assumption? Please provide confidence intervals for that assumption.

b) Please provide the detailed calculations in electronic format, as to how the 4.4 cents/kw.h for the A-Trains and the 6.3 cents/kw.h for the Tridem units are calculated.

c) Please determine the range of LNG fuel cost savings, as shown above, using efficiencies of 30 and 35 percent.

ANSWER:

(a)

The 40% conversion efficiency is a considered to be reasonable minimum average efficiency for the selected gas engines. Please see response to YUB-YEC-1-34(a through c).

(b)

Please see response to YUB-YEC-1-44 for determination of the A-Train and Tridem cost estimates used in the Application (February 2013 previous estimate) and the current update (with Attachment 1 to that response in electronic format). Using the earlier estimates as per the Application, the following demonstrates how the 4.4 cents/kW.h for the A-Train and 6.3 cents/kW.h for the Tridems were calculated:

- A-Trains:
  - Haul cost (Calgary-Whitehorse) at $4.37/MMBtu plus 18% premium equals $5.16/MMBtu
  - LNG requirement per kW.h at 40% conversion efficiency equals 8530 Btu/kWh [3412/0.4] or 0.0085303 MMBtu
  - LNG cost per kW.h then equals $5.16*0.0085303=$0.044

- Tridems
  - Haul cost (Calgary-Whitehorse) at $6.76/MMBtu plus 10% premium equals $7.44/MMBtu
  - LNG requirement per kW.h at 40% conversion efficiency equals 8530 Btu/kWh [3412/0.4] or 0.0085303 MMBtu
  - LNG cost per kW.h then equals $7.44*0.0085303=$0.063

(c)

Please see Table 1 for the LNG fuel savings with 30% and 35% efficiencies compared to diesel fuel cost at 24.6 cents/kW.h and 20 cents/kW.h.

Table 1:
Range of LNG Fuel Cost Savings with 30% and 35% Efficiencies

LNG Fuel Cost Saving ($/kW.h)			
New Diesel	LNG		LNG Saving
		A-Train from Calgary with 18% premium	
0.246	0.169	gas at $3.5/MMBTu, efficiency 30%	0.077
0.200	0.169	gas at $3.5/MMBTu, efficiency 30%	0.031
0.246	0.149	gas at $4.5/MMBTu, efficiency 35%	0.097
0.200	0.149	gas at $4.5/MMBTu, efficiency 35%	0.051
		Tridem from Calgary with 10% premium	
0.246	0.194	gas at $3.5/MMBTu, efficiency 30%	0.052
0.200	0.194	gas at $3.5/MMBTu, efficiency 30%	0.006
0.246	0.172	gas at $4.5/MMBTu, efficiency 35%	0.074
0.200	0.172	gas at $4.5/MMBTu, efficiency 35%	0.028

TOPIC: **Design modification risks**

REFERENCE: **Application, page 48**

Yukon Energy does not anticipate material risks of major design modifications resulting from regulatory approvals and review process for this Project. The proposed Project will be built using conventional construction technologies suited for northern climate conditions, and following all applicable construction and design practices for works of this nature, including building and electrical codes and adhering to industry best practices. The technologies employed in the Project for the LNG facilities and the GE J624 modular gas-fired engines are industry standard in all material respects and proven in northern climate conditions. The Project will also adhere to all applicable national and territorial standards used in the design of all Project components.

Stringent standards and regulations for design, construction and operation for LNG transport, storage and vapourization facilities have developed over the last 40 years to prevent accidents and minimize the adverse impacts of events. LNG facilities must meet all standards, codes and regulations enforced by federal, provincial/ territorial or municipal jurisdictions. Accordingly, no special added costs are anticipated at this time to be required for the Project to comply with anticipated material conditions in approvals or permits.

The major regulatory risk for the Project remains material delays in schedule, which could adversely affect Project costs and benefits for ratepayers starting in winter 2014/15.

PREAMBLE:

The Board needs further information.

QUESTION:

a) Does YEC anticipate design modifications resulting from the YESAB review?

b) Please provide additional information that shows the technologies employed in the project for the LNG facilities and the GE J624 modular gas-fired engines are industry standard.

c) Please explain what constitutes "material delays in schedule." Has YEC included contingency costs in its proposal to account for delays that may adversely affect LNG project costs?

d) Please provide examples of industry best practices respecting LNG projects YEC is referring to in the above quote.

e) Please provide examples of LNG facilities that have developed over the last 40 years.

f) Are added costs anticipated at this time?

ANSWER:

(a) and **(f)**

YEC does not anticipate any design modifications or added costs resulting from the YESAB review. The updated estimated Project capital costs are provided in YUB-YEC-1-1(d).

(b)

The GE J624 modular gas-fired engines are modern units and LNG facilities (i.e., LNG storage tanks, vapourizer and related equipment) are each being supplied by an established and reputable supplier and meet all YEC technical requirements as well as all regulatory requirements and codes.

(c)

The referenced statement in the Application addresses any delay that would prevent the Project from providing most of the potential diesel displacement benefits (assuming long-term average hydro conditions) for the winter of 2014/15; material delays in this context would imply inability to be in commercial operation sometime in January 2015. For

further discussion of delay-related risks and potential cost impacts, please see response to YUB-YEC-1-2(a) and (b). YEC has not included contingency costs in its proposal for material delays that may adversely affect Project costs.

(d)

Stringent standards and regulations for design, construction and operation for LNG transport, storage and vapourizaton facilities have developed over the last 40 years to prevent accidents and minimize the adverse impacts of events. LNG facilities in Yukon must meet all standards, codes and regulations enforced by federal, provincial/ territorial or municipal jurisdictions, including the following:

- Yukon Gas Processing Plant Regulation will apply to ensure that gas processing facilities in Yukon are designed, constructed and operated safely.

- The Canadian Standards Association has established the essential requirements and minimum standards for design, installation and safe operation of LNG facilities in CSA Z276-11 – Liquefied Natural Gas (LNG) – Production, Storage and Handling.

- Potential issues regarding safety of LNG have also been identified and addressed in various US codes that have been developed by the NFPA and under the Uniform Fire Code.

- The LNG industry also follows additional codes, rules, regulations and standards established by organizations such as the Society of International Gas Tanker and Terminal Operators, the Gas Processors Association and the NFPA.

The standard in Canada is published by the Canadian Standards Association (CSA) under the title of CSA Z276-11, “Liquefied natural gas (LNG) — Production, storage, and handling”. CSA-276 was first published in 1972 and has been revised 9 times over the years as experience has been gained and technology has improved. CSA-276 has an extremely close cooperation with the [US] National Fire Protection Association (NFPA) 59A, “Standard for the Production, Storage and Handling of LNG”.

CSA Z276-11 establishes essential requirements and minimum standards for the design, installation, and safe operation of liquefied natural gas (LNG) facilities, and sets out

requirements for LNG equipment and facility design, equipment fabrication, facility construction, operation, emergency response, maintenance and personnel training. It also requires compliance through reference to additional codes and standards that set the requirements for state of the art material selection, equipment selection, equipment fabrication techniques and requirements, testing requirements, electrical codes, and so forth. CSA Z276-11 prescriptively sets forth requirements for safe separation distances for credible leak events that protect the public from LNG vapour releases and thermal radiation that could result if the vapours from an LNG leak were to catch fire.

It is also noted that all trailers used to transport LNG must also be code compliant with the requirements of Transport Canada B620 TC-341. This standard sets out the requirements for design, construction, certification, assembly, modification, repair, testing, inspection, periodic re-testing, maintenance, and marking of highway tanks (tank trucks) for the transportation of dangerous goods.

(e)

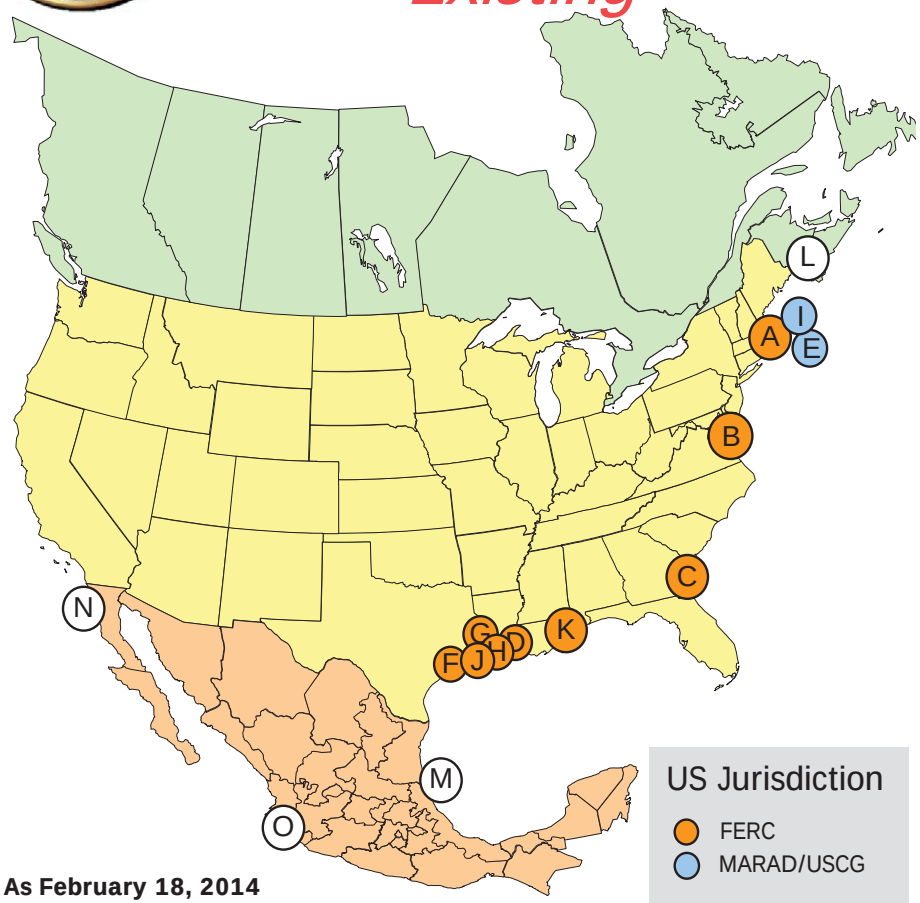
Over the last 40 years, well over 100 large LNG facilities (i.e., peak shavers or LNG Import Terminals) have been built in North America in compliance with either NFPA-59A or CSA Z276-11 standards (large facilities include LNG peak shavers and import or export LNG terminals).This includes the following four peak shavers in Canada: one owned by Fortis on Tilbury Island, BC built in 1970, one owned by Fortis west of Mt. Hayes on Vancouver Island built in 2011, one owned by Gaz Metropolitain in eastern Montreal and one owned by Union Gas near Hagar, Ontario. Canaport in Saint John, New Brunswick is the single Canadian LNG terminal. Please see Attachment 1 to this response for further detail regarding locations of North American import/export terminals and peak shaving facilities.

In addition to the above referenced large facilities, a number of small scale LNG facilities and LNG fueling stations have also developed over the past 40 years[1].

[1] These facilities may have been built to NFPA-59A or CSA Z276-11; however, some of the smaller facilities may also have been built to NFPA-52, Vehicular Gaseous Fuel Systems Code which applies to all facilities with LNG storage in containers of 70,000 gallons or less.

North American LNG Import/Export Term

Existing



As February 18, 2014

U.S.

A. Everett, MA : 1.035 Bcfd (GDF SUEZ - DOMAC)
B. Cove Point, MD : 1.8 Bcfd (Dominion - Cove Point LNG)
C. Elba Island, GA : 1.6 Bcfd (El Paso - Southern LNG)
D. Lake Charles, LA : 2.1 Bcfd (Southern Union - Trunkline LNG)
E. Offshore Boston: 0.8 Bcfd, (Excelerate Energy – Northeast Gateway)
F. Freeport, TX: 1.5 Bcfd, (Cheniere/Freeport LNG Dev.) ★
G. Sabine, LA: 4.0 Bcfd (Cheniere/Sabine Pass LNG) ★
H. Hackberry, LA: 1.8 Bcfd (Sempra - Cameron LNG) ★
I. Offshore Boston, MA : 0.4 Bcfd (GDF SUEZ – Neptune LNG)
J. Sabine Pass, TX: 2.0 Bcfd (ExxonMobil – Golden Pass) (Phase I & II)
K. Pascagoula, MS: 1.5 Bcfd (El Paso/Crest/Sonangol - Gulf LNG Energy LLC)

Canada

L. Saint John, NB: 1.0 Bcfd, (Repsol/Fort Reliance - Canaport LNG)

Mexico

M. Altamira, Tamulipas: 0.7 Bcfd, (Shell/Total/Mitsui – Altamira LNG)
N. Baja California, MX: 1.0 Bcfd, (Sempra – Energia Costa Azul)
O. Manzanillo, MX: 0.5 Bcfd (KMS GNL de Manzanillo)

Note: There is an existing import terminal in Peñuelas, PR. It does not appear on this map since it can not serve or affect deliveries in the Lower 48 U.S. states.

★ *Authorized to re-export delivered LNG*

Office of Energy Projects

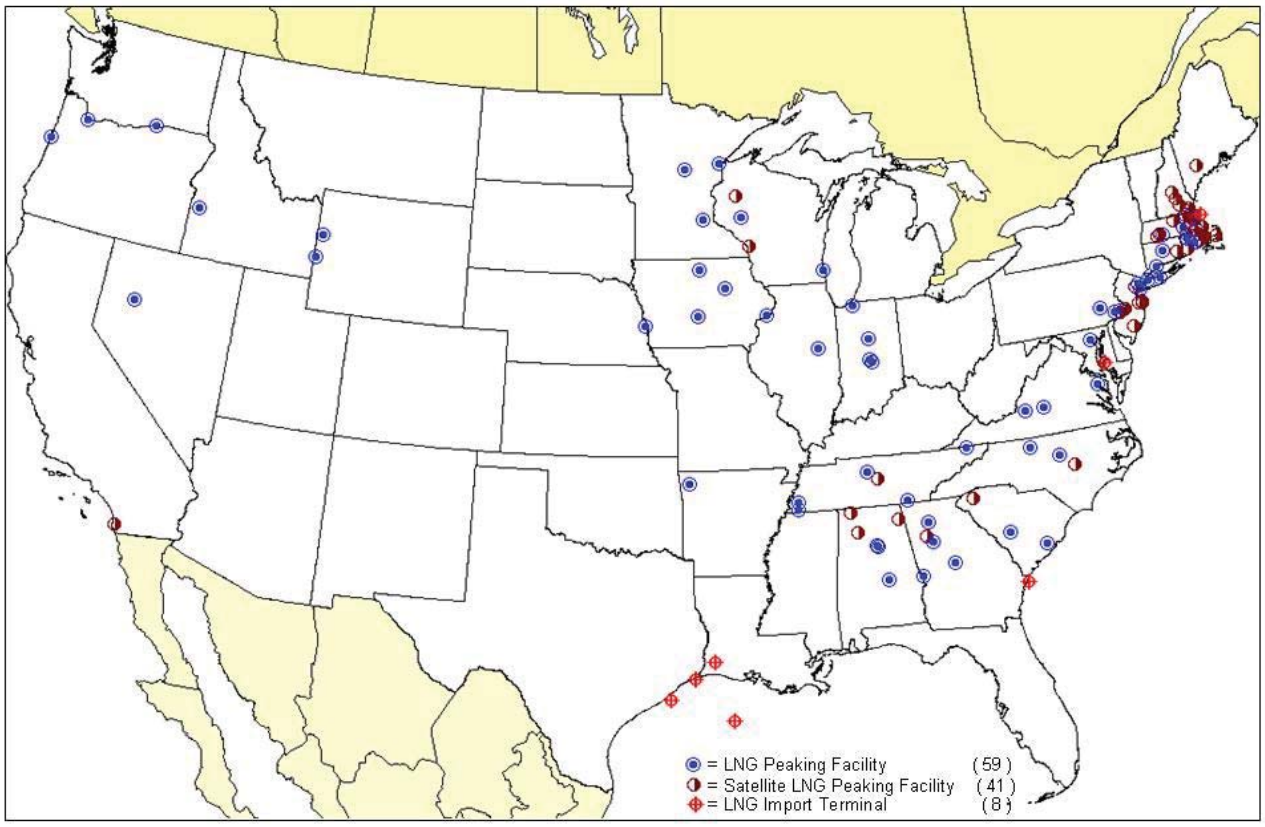
U.S. Energy Information Administration

NATURAL GAS

About U.S. Natural Gas Pipelines - Transporting Natural Gas

based on data through 2007/2008 with selected updates

U.S. LNG Peaking Shaving and Import Facilities, 2008



Note: Satellite LNG facilities have no liquefaction facilities. All supplies are transported to the site via tanker truck.
Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division Gas, Gas Transportation Information System, December 2008.

The EIA has determined that the informational map displays here do not raise security concerns, based on the application of the Federal Geographic Data Committee's *Guidelines for Providing Appropriate Access to Geospatial Data in Response to Security Concerns*.

TOPIC: Summary description

REFERENCE: Application, page 4 and 14

The precise location of each component of the Project will be finalized upon completion of detailed engineering design and permitting by regulators following assessment under the Yukon Environmental and Socio-economic Assessment Act ("YESAA").

The Project lies within the Traditional Territory of the Kwanlin Dün First Nation ("KDFN") and the Ta'an Kwäch'än Council ("TKC"). In May 2012, TKC and KDFN were invited to become partners in assessing the feasibility of using LNG as a fuel source in Yukon and agreed to co-develop a Partnership Committee with terms of reference and signed confidentiality agreements completed July 2012. Regular partnership meetings have been held since July 2012, focused on review of the business case, establishing a good working relationship and making substantive progress toward developing economic and business opportunities for the two First Nations relative to the Project. This has also included discussion regarding a possible investment in the Project by TKC and KDFN through negotiation of a Partnership Agreement.

Other positive effects include the potential for local jobs and business activity during the construction period (including opportunities for KDFN and TKC), savings for Yukon ratepayers compared to what would be required with continued reliance on diesel generation, and potential business and employment opportunities for KDFN and TKC.

PREAMBLE:

The Board requires further information.

QUESTION:

a) Considering that detailed engineering design is yet to be finalized, how accurate are YEC's forecast LNG project costs in terms of +/- percentages?

b) Would YEC consider a deferral account to protect its customers from cost overruns?

c) Please provide updates regarding the discussions with the two First Nations' possible investment in the LNG project through negotiation of a partnership agreement.

d) If a partnership agreement has been entered into with the two First Nations, please provide the terms of reference and detail the cost impacts, if any, to customers.

e) Have the costs related to the partnership agreement been taken into account respecting the cost/benefit analysis of this project?

ANSWER:

(a)

The preliminary cost estimates included a contract proposal for the largest single cost equipment (the gas-fired engines and related equipment); excluding the engine related costs and decommissioning, the remaining cost estimate of $21.6 million was subject to cost risks overall of at least +20% to address risks related to regulatory review, the White Pass lease, detailed engineering design and costing, and contract tendering.

Please see response to YUB-YEC-1-1(d) which provides capital cost updates in late January 2014 based on the current regulatory review process, final site configuration (i.e., no lease of the White Pass lands), contractual costs for selected key long lead equipment (two GE engines [Gas Drive], three LNG storage tanks [499.5 m^3 total capacity], skid mounted vaporization and related equipment, and transformer), updated site layout design, and contractual costs for Project Management and Project Engineering. Contingencies of $1.45 million are included in the update, with $1 million for construction contracts (primarily for the untendered civil, mechanical and electrical contracts estimates at $6.8 million as part of Site Development costs) and the balance for Engineering, Project Management and Owners as noted in Table 1. The intent of the updated capital cost estimate is to include contingencies that address anticipated risks; however, as noted in response to YUB-YEC-1-2, the Project is subject to schedule risks that are not covered in the estimated cost contingencies, as well as normal risks that final contracting costs on yet-to-be tendered elements may exceed the current cost estimates including contingencies.

(b)

It is not understood how a deferral account would protect customers from cost overruns. In order to be included in rates Project costs (including cost overruns) must be approved by the Board as reasonable and prudently incurred costs. Yukon Energy expects that after the Project is in service it would apply to include all Project costs in rate base at the time of the next General Rate Application. It is expected that such Project costs would be amortized over the 40 year life of the Project.

(c)

As noted in the Application (page 4), KDFN and Ta'an were invited to become partners in assessing the feasibility of using LNG as a fuel source in Yukon and agreed to co-develop a Partnership Committee with terms of reference and signed confidentiality agreements completed July 2012.

Regular partnership meetings were held starting July 2012 and focused on review of the business case, establishing a good working relationship and making substantive progress toward development economic and business opportunities for the two First Nations relative to the Project. This included discussion regarding a possible investment in the Project by Ta'an and KDFN through negotiation of a Partnership Agreement.

After the Application was filed Ta'an notified YEC in a letter on December 18, 2013 that it was withdrawing from the partnership discussions.

KDFN remains fully supportive of the Project, and Yukon Energy has continued discussions with KDFN towards a Project agreement and it is expected that this agreement would be concluded in the near future. The agreement is expected to address service and supply contracting opportunities related to the Project, provisions for an investment opportunity in the Project and access to any surplus LNG supply capacity and inventory as part of a potential physically and financially separate wholesale/retail natural gas facility to be developed by KDFN. The agreement and specific terms of the agreement are subject to the provisions of the confidentiality agreements between the Project partners.

(d) and **(e)**

As noted in part (c) above, a final Project agreement has not yet been concluded between YEC and its partner and ongoing discussions are subject to provisions of a confidentiality agreement.

There are no specific or significant cost impacts to ratepayers anticipated by the Project agreement. The costs related to the development of an agreement have not been significant to date. The parties have been meeting regularly for 21 months with each party carrying their own participation costs and no identifiable cost premiums are expected to the Project from the Partner's execution of opportunities under the agreements.

TOPIC: **Ratepayer Impacts**

REFERENCE: **Application, page 29 and page 32, Table 4-3; Appendix D, Tables D-1 and D-2; Appendix C, Table C-2**

The annual fuel cost estimates in Table 4-3 assume long-term average thermal generation requirements are supplied with the new and more efficient gas or diesel generation units being operated on a prioritized basis where feasible to maximum capacity prior to use of any other grid diesel generation. The annual fuel costs estimates in Table 4-3 also assume operation of these new units to enhance hydro storage use in wintertime (so that enhanced hydro generation can help displace diesel generation during periods of peak diesel requirements).

PREAMBLE:

The Board seeks clarification of this statement both with respect to the use of new gas or diesel units to enhance hydro storage use in wintertime and its effect on fuel costs.

QUESTION:

a) How does YEC propose to operate new gas or diesel units in a manner that would enhance hydro storage use in wintertime? Specifically refer to the values in the tables in Appendices C and D in your discussion, using the actual plant capacities proposed for both the LNG and new diesel projects in the sequence proposed (13.2 MW for LNG and 13.4 MW for new diesel).

b) What is the cost in each case in each of the years 2015 to 2018 to achieve this benefit?

c) Please explain how the amount and value of enhanced hydro was calculated and incorporated into Table 4-3. Please provide a table showing the calculations.

d) In Table 4-3, how were the values for fuel displacement arrived at, given there is no reference to 2018 in Appendix D?

e) What might be the opportunities for LNG or new diesel unit operation to enhance hydro storage use in wintertime beyond 2018 to 2020?

ANSWER:

(a) through **(e)**

The Application reviews these matters at pages 29 to 31 and Appendix D. Analysis to date, as reviewed in the Application, provides an estimate of potential annual displacement of default “old” diesel requirements (based on long term average hydro generation and forecast assumptions in Appendix C for each load scenario) with different levels of new diesel or new gas engine capacity. As reviewed at pages 31 and 32 of the Application, the Appendix D analysis uses YECSIM analysis of the 31 water years to develop these estimates, taking into account the extent to which high utilization operation of such new units could be expected to augment hydro storage on the grid – and indicating the extent to which such augmented storage and operation of the new thermal units would be able to displace "old” default diesel generation during even extreme drought years (including as indicated a sequence of several such years).

Based on this analysis, estimates of potential “old” diesel displacement with different levels of gas engine capacity were developed in Appendix D specifically for 2015, 2016 and 2017 forecast Base Case loads without Alexco. Table 4-3 reflects these estimates for these years with the LNG option:

- Assuming 8.8 MW of gas engine capacity for 2015 and 2016, the Appendix D analysis was used in Table 4-3 to support an assumed 100% old diesel displacement in 2015 and 95% displacement in 2016;

- Assuming 13.1 MW of gas engine capacity in 2017, the Appendix D analysis was used in Table 4-3 to support an assumed 100% old diesel displacement in 2017;

- Table 4-3 also assumed (without specific new Appendix D analysis, but relying on what can be reasonably inferred from the Appendix D 2017 analysis) that 100% displacement would also apply with 13.1 MW gas engine capacity for this load scenario in 2018.

Table 4-3 also had to assume old diesel displacement levels for the same Base Case forecast with new diesel capacity of 6.7 MW in 2015 and 13.4 MW each year thereafter. For simplicity, the same Appendix D information was utilized to support an assumed 90% old diesel displacement by the new diesel in 2015 and 100% displacement in 2016, 2017 and 2018 with the Base Case load forecast. As reviewed in response to YUB-YEC-1-36(a, c, and d), given the higher fuel cost for diesel than for gas, diesel generation is much less likely than gas generation to be operated for the purpose of facilitating added hydro storage – and therefore the assumed new diesel displacement percentages in Table 4-3 are less likely to occur in practice than the assumed gas displacement percentages.

YEC does not propose to operate new gas or diesel units in the year round manner assumed for each year in Appendix D. This analysis reviewed above was adopted to assess potential displacement of old diesel that might occur under the Base Case and specific gas engine capacities during initial years of operation.

In practice, as reviewed in YUB-YEC-1-36(a), maximum operation of the gas-fired units would not be planned automatically during each year, but would be planned based on when it was determined to be effective in adding to hydro storage (as well as when directly needed to displace diesel generation). The footnote 40 comment in the Application recognizes that the hydro storage maximization assumed in Appendix D would likely not be fully realized under all potential conditions. Experience will be needed over time to determine the extent to which gas-unit operation can be cost-effectively planned with regard to provision of added hydro storage such that optimum diesel displacement is achieved from gas-unit operation.

If the existing diesel units are otherwise used to supply energy forecast in the model when hydro is not available, the gas-fired generation would be reduced below what is assumed in Table 4-3 by the equivalent amount (GW.h) supplied through the existing diesel units. However, YEC has no basis to forecast or estimate at this time what, if any, such reduction may occur in any year – or to estimate what added gas fuel costs might be incurred to facilitate added hydro storage that in the end is not used to displace old diesel use.

TOPIC: **Ratepayer Impacts**

REFERENCE: **Application, page 8, Table 3-1, footnote 1, and page 25**

This work to decommission WD1andWD2 ($1.45 million) is expected to occur in summer 2015; all other work is expected to be completed before the end of 2014.

PREAMBLE:

QUESTION:

a) Once these units are decommissioned and salvaged, what does YEC propose to do physically with these units?

b) What salvage value will these units have, either in whole or in parts? Will that value be allocated back to ratepayers? If yes, how will it be allocated?

c) Is any of this salvage value reflected in Table 4-3? If so, where and how?

ANSWER:

(a)

As indicated in the Application, YEC will consider cannibalizing the units for parts that will be useful for maintaining the two Mirrlees still in the fleet (FD1 & WD3). After that, the Corporation will seek the least cost option to disposing of the units (sale or salvage).

(b)

The expected salvage value is not known at this time; however, to the extent the Corporation is successful in generating proceeds from the disposal, this income will be offset against the costs to decommission the units (net value to be charged off to the Reserve for Future Removal and Site Restoration).

(c)

As indicated in part (b) above, expected salvage value is not known at this time and consequently is not reflected in Table 4-3 or in the updated capital cost estimates in YUB-YEC-1-1(d).

TOPIC: **Project alternatives**

REFERENCE: **Application, page 24 and page 25**

The current situation differs from that reviewed in many respects, including current forecasts for grid diesel generation as well as updated assessments of the practicality and cost requirements for this option.

Based on the Corporation's recent experience with refurbishment and subsequent maintenance of the WD3 Mirrlees in Whitehorse and FD1 Mirrlees in Faro, the following have been concluded...

PREAMBLE:

On pages 24 and 25, in Section 4.2.3 - Diesel Generation Alternatives to the Project, YEC discusses the issue of life extension of WD1 and WD2.

QUESTION:

a) Please provide further discussion of the specific physical and cost issues that lead YEC to conclude that it is impractical and not cost effective to carry out a life extension of WD1 and WD2.

b) Please provide details regarding YEC's plans to utilize some of the parts off the retiring units to keep WD3 and FD1 operating through to currently planned retirement dates.

c) Please provide details regarding YEC's statement that if parts were not an issue, a life extension for WD1 and WD2 would cost $6.75 million.

d) Why is there a risk that the capital costs would exceed the $6.75 million? What forms the basis for this statement?

e) What forms the basis for the per-MW cost estimates cited in footnote 32, at the bottom of page 25, both for existing and new units?

ANSWER:

(a), (c), and **(d)**

Please see response to YUB-YEC-1-13 which reviews a range of issues related to WD1 and WD2 as discussed in the Application at the pages referenced in this question.

Risks that capital costs will exceed the level noted relate to risk for balance of plant work in an old existing building, as well as risks in securing parts (and costs that may be incurred addressing such issues).

(b)

Please see response to YUB-YEC-1-20.

(e)

Cost estimates in footnote 32 of a minimum $1.5 million per MW likely for a new unit in an existing facility without extensive balance of plant cost requirements such as are expected to be required at the WTGS today reflect preliminary engineering and costing done by YEC in 2012/2013 when assessing options to install new units in the WD1 and WD2 service bays.

TOPIC: **Capital costs**

REFERENCE: **Application, page 32, Table 4-3**

PREAMBLE:

QUESTION:

a) Can YEC confirm that the capital costs cited in Table 4-3 for the initial cost of each alternative includes the $1.45 million salvage costs of the WD1 and WD2 units cited in footnote 1 of Table 3-1 on page 8? What about the $0.3 million in BOP-Preliminary Assessment costs cited in Table 3-1 itself?

b) Can YEC clarify what costs are included in BOP-Preliminary Assessment?

c) Can YEC confirm that both of these costs are capitalized in Table 4-3 under the year 2014 and a return on those costs is included in both of the lines “Return Diesel (new)” and “Return LNG” for the years 2015 through to 2018?

ANSWER:

(a)

Confirmed that the $1.45 million and the $0.3 million are included in the referenced tables in the Application.

(b)

The BOP-Preliminary Assessment costs of $0.29 million included in Table 3-1 of page 8 of the Application are preliminary engineering costs related to diesel plant that was not related to the Project. These costs have been removed from the updated Project capital cost estimate as noted in response to YUB-YEC-1-1(d).

(c)

Confirmed for Table 4-3 in the Application, with provision that salvage costs are excluded from depreciation but reflected in return on mid-year rate base. For the updated Table 4-3, the updated Project capital cost estimates have been used (the updated salvage costs are $0.55 million for the Project and $0.95 million for new diesel; BOP-Preliminary Assessment costs are not included for either the Project or new diesel). Please see YUB-YEC-1-1(d) for updated Project capital costs and YUB-YEC-1-13(a) for updated Table 4-3.

TOPIC: **Project alternatives**

REFERENCE: **Application, page 26**

For comparative purposes, an alternative has been examined assuming two new 6.7 MW diesel engines (13.4 MW)...

PREAMBLE:

QUESTION:

a) Can YEC confirm that the two diesel units cited for comparative and cost purposes are in fact the 6.7 MW Wartsila dual fuel engines cited in footnote 35 at the bottom of page 26?

b) What additional capital costs are associated with the selection of a dual fuel engine for comparative purposes, both in terms of the engine itself and any additional associated plant requirements?

c) In the costing of the new diesel alternative, were any additional costs associated with running the proposed units on LNG included?

d) Referring to footnote 35 at the bottom of page 26, why would these units be selected to replace WD1 and WD2?

ANSWER:

(a)

Yukon Energy confirms that the two diesel units cited for comparative and cost purposes are in fact the 6.7 MW Wartsila dual fuel engines cited in footnote 35 at page 26 of the Application.

(b)

The dual fuel option compared to diesel fuel only option is estimated to cost about $500k more per 6.7 MW engine (10%), which was within the range of prices received from the engine vendors. There were no off-engine natural gas infrastructure costs added to the dual fuel engine cost.

(c)

No.

(d)

The dual fuel Wartsila engines were selected initially for the assessment of the diesel conversion to gas project analysis based on being competitively priced and in the appropriate capacity range that could fit within the Mirrlees bays (see YUB-YEC-1-23(b)). Given that preliminary engineering costing had been developed for installation of these engines, the costs developed for these units were retained for the "new diesel" comparisons.

TOPIC: **Project alternatives**

REFERENCE: **Application, page 23**

However, retention of the WD1 and WD2 Mirrlees units beyond planned retirement would expose all grid customers to unreliable generation capacity as well as higher O&M fuel costs, and replacement or life extension of these units would be required in any event as soon as feasible, i.e., by late 2015 at the latest.

Exposure of grid customers to unreliable generation that fails to meet the grid reserve capacity planning criteria, as would occur with this option, is not acceptable to Yukon Energy.

PREAMBLE:

QUESTION:

a) Why does YEC assert that the two existing WD1 and WD2 units are unreliable and their retention in their current condition, even in the short term, i.e. through 2015, is unacceptable?

b) What evidence can YEC present from their operations and maintenance records that demonstrate such unreliability?

c) In terms of grid reserve capacity planning criteria (with no retirement of WD1 and WD2 and without either of the LNG or new diesel options):
   i. given YEC's current baseload forecast, does the need for additional new capacity occur at the beginning of 2016?
   ii. does the retention and operation of the WD1 and WD2 units over the winter of 2014-2015 meet the grid reserve capacity planning criteria?
   iii. depending on the accuracy of the baseload forecast, is it possible that the retention and operation of the WD1 and WD2 units might still meet that criteria beyond the start of 2016, given the magnitude of the projected deficiency in capacity at the beginning of 2016?

ANSWER:

(a) and **(b)**

Please see response to YUB-YEC-1-13, which addresses a range of issues raised regarding WD1 and WD2, including those asked here.

(c)

If there is no retirement of WD1 and WD2, and it is assumed that these units are still "reliable" notwithstanding YEC's conclusion that this is not the case, then 8.0 MW of de-rated capacity would not be removed from the existing peak winter capacity. Assuming no other new capacity is added, there would be N-1 surplus MW until 2016 (when the shortfall would be 0.5 MW, starting at the beginning of the year). The capacity planning criteria are a guide for planning and therefore the extent to which a 0.5 MW shortfall would always necessitate new capacity would need to be assessed in the context of all available information at the time the planning was carried out.

The grid reserve capacity planning criteria as such do not determine when a unit is no longer reliable. YEC has made the determination that these units in Whitehorse, Yukon's largest load centre, are now end of life – and ongoing non-industrial load growth on the grid is highlighting the relevance today of ensuring that all capacity included in reserve capacity planning is in fact truly reliable and effective when and if needed during an N-1 event during winter peak periods.

TOPIC: **Project scope**

REFERENCE: **Application, page 4 and page 8**

Two natural gas-fired units (8.8 MW total capacity) are anticipated to be in service Q4 2014 to provide capacity and fuel cost savings during the winter of 2014/2015. Projected in-service for the third natural gas-fired unit (4.4 MW) will occur as required to meet grid capacity planning requirements, and is anticipated to be within a few years after the first two units are in service.

Yukon Energy does not at this time have firm pricing for the third GE natural-gas fired generating unit – the $4.4 million estimate continues to be the best available information at this time.

PREAMBLE:

Clarification about the scope of the project is sought.

QUESTION:

a) Can YEC clarify whether the scope of the project includes the third 4.4MW natural gas-fired unit to be installed at an undetermined date beyond the end of 2014?

b) If the installation date and the cost of the third unit are as yet undetermined, why should the Board consider approval of the third unit and any associated facilities within the scope of the applied-for project?

ANSWER:

(a)

The Project scope includes the third 4.4 MW natural gas-fired unit[1].

The third 4.4 MW unit is to be installed as required to meet grid capacity planning requirements. Based on the updated Base Case load forecast provided in Appendix C of the Application, the currently projected in-service date for the third natural gas-fired unit (the additional 4.4 MW of generation capacity) is late 2016 in order to ensure that the capacity shortfall forecast for 2017 will be fully addressed (see also response to YUB-YEC-1-8(a)).

(b)

The terms of reference provided require the YUB to submit a report and recommendations to the Minister on the Project as designated by OIC 2013/200 (which entails "the partial conversion of the generating station from diesel fuel to natural gas fuel, with the replacement of two existing diesel generating units by three natural gas fired generating units").

Under the terms of reference the Board may comment on the necessity for the Project, as well as its timing and design. While the Board does not have the jurisdiction to approve the Project, it may recommend to the government conditions for undertaking further stages of the Project (similar to its recommendations following the Carmacks-Stewart Transmission Project Part 3 hearing where the Board recommended that YEC not pursue Stage Two of the CSTP unless there is a firm commitment to connect a new mine load, and under the condition that ratepayers would not be adversely affected).

The Application proposes clear conditions required for YEC to proceed with the third unit, i.e., the third 4.4 MW unit is to be installed as soon as is required to meet grid capacity planning requirements. Assuming that the first two units and the LNG facilities (unload, storage and vaporization and related facilities) are developed, the only

[1] The Project scope as set out at page 4 of the Application involves replacing two diesel generating units scheduled for retirement in the existing WTGS by 2015 (9.1 MW total capacity) with three new modular natural gas-fired generating units (13.1 MW total capacity), and the installation of LNG truck offloading, storage and vapourization and related infrastructure on the Expanded Site Area.

incremental costs required for the third unit related to acquisition and installation of the unit, i.e., the basic costs as required simply to provide the required added grid capacity without any material added costs related to LNG facilities.

Please also see response to YUB-YEC-1-30(a), (b), and (c).

TOPIC: **Project capital costs**

REFERENCE: **Application, page 26**

For comparative purposes, an alternative has been examined assuming two new 6.7 MW diesel engines (13.4 MW), with the first unit installed in 2014 at an estimated capital cost of $22.5 million...and the second unit installed in late 2015 at an estimated capital cost of $11.0 million...

PREAMBLE:

QUESTION:

a) Provide a table similar to Table 3-1, shown on page 8 that gives a breakdown of the $33.5 million in capital costs of the new diesel development alternative discussed in the Application.

b) Discuss the main differences in each of the cost components between the tables for the LNG and the new diesel case.

ANSWER:

(a) and **(b)**

Please see response to YECL-YEC-1-6(b) for a table similar to Table 3-1 with a breakdown of the $32.7 million in updated capital costs of the new diesel development alternative discussed in the Application.

The new diesel cost does not include costs related to LNG site development and LNG storage. However, under new diesel option the balance of work related cost expected to be higher.

TOPIC: **Project capital costs**

REFERENCE: **Application, page 8**

PREAMBLE:

QUESTION:

a) Please provide a version of Table 3-1 that shows a breakdown of the complete capital cost ($38.8 million) of the project, including the third gas-fired unit.

b) Please provide a version of Table 3-1 that shows a breakdown of the current estimate of the capital cost ($4.4 million) of the third gas-fired unit by itself.

c) What is the capital cost on a per-MW basis of the total $38.8 million of the project, similar to the $3.9 million cited in the second paragraph on page 8?

ANSWER:

(a) and **(b)**

An updated version of Table 3-1 that includes the third engine and shows a breakdown of the current estimate of the capital cost of the third gas fired unit by itself cannot be provided at this time.

As noted in response provided to YUB-12(c) and (d), Yukon Energy does not at this time have firm pricing for the third GE natural gas-fired generating unit - the $4.4 million estimate is the best available information. The $4.4 million estimate is intended to include the costs to acquire and install the unit, assuming that the construction completed in 2014 has provided all required civil facilities, switchgear, fluid transfer station facilities, LNG facilities, and substation requirements.

(c)

The capital cost per MW for 13.1 MW (3 engines with total capital cost of $38.8 million as assumed in the Application) is $2.9M /MW, versus $3.9M /MW for 8.8 MW in the first

stage. However, as noted in response to YUB-YEC-1-1(d), the cost for the first stage of the Project (first two engines) has increased from $34.4 million to $36.5 million. Further, as noted in (a) and (b) above, YEC does not at this time have an updated cost estimate for the third engine. Finally, it is noted that these average costs per MW included costs for installation of the initial LNG facilities (truck unload, vapourization and LNG storage).

TOPIC: **Project capital costs**

REFERENCE: **Application, page 8, Table 3-1,**

PREAMBLE:

In Table 3-1, page 8, YEC cites the costs of the LNG Gen - Engines as being $11.4 million, which if divided by two, gives a cost of $5.7 million per unit. When compared to the $4.4 million capital cost cited to install the third unit by itself, these costs on a per-unit basis are $1.3 million higher.

QUESTION:

a) What accounts for this difference in cost between the first two units and the third unit?

b) Are there any financial advantages to buying all three units at the same time? If so, please explain.

ANSWER:

(a) and **(b)**

There were advantages to purchasing all three GE units at the same time. However, as noted in the Application, the earliest requirement for the third unit (based on capacity planning criteria) is not anticipated until a few years after the first two units are in service., i.e., as noted in Table C-4 of Appendix C, with the added 8.8 MW from the two new gas-fired generators there is a 2.1 MW shortfall starting in 2017, growing to 4.2 MW in 2018. It is understood that grid conditions (load or advancement of other supply options) may change over this period. As such, it was not considered prudent to purchase the third unit at this time.

TOPIC: **Project capital costs**

REFERENCE: **Page 40, capital cost increase risks and other construction risks**

The GE Engines are the largest cost component for the Project (33% of the total WTGS capital costs) - there is a high degree of certainty regarding this cost component as Yukon Energy has entered into an EPC contract with GE/Gas Drive to engineer, build, deliver and install the units (including related switchgear) on site.

YEC is also concluding at this time contract arrangements related to the key LNG facilities equipment, including storage tanks and vaporizer.

PREAMBLE:

QUESTION:

a) Were the contracts for the LNG generators, the storage facilities, the vaporizer and each component's installation tendered? If they were not tendered, explain why not?

b) If they were tendered, please provide details of the tendering process, including pricing received and names of all bidders.

ANSWER:

(a) and **(b)**

The vendor selection and contracting processes varied for the different major equipment items noted, as reviewed below. Responses to other information requests are noted for additional detail.

LNG Generators

Please see responses to YCS/LE-YEC-1-5(a, b, d, e, and f) and YUB-YEC-1-15(a through e).

In summary, YEC carried out a Request For Information (RFI) Process in January 2013 for new engines options to be located within the diesel plant. Five responses were received. As a result of discussions with the short listed vendors and completion of a preliminary engineering study on the Balance of Plant costs that would be required to put new engines into the Mirrlees bays in the diesel plant, Yukon Energy decided to pursue initial conversion through the option of smaller pre-engineered modular gas units installed on a pad outside the existing diesel plant.

In addition to information initially provided by GE confirming the availability of the 4.375 MW modular gas-fired reciprocating engine option (as well as demonstrated cold-climate northern operating experience), information was obtained from Wartsila, MAN, Cummings and Caterpillar. Wartsila did offer a modular gas cube design powerhouse in Europe but it did not offer the product in North America, nor did they recommend the product in cold climates. MAN was not able to offer a specific modular package to Yukon Energy. Cummings and Caterpillar were only able to offer modular package based on smaller units less than 2 MW's which were not suitable for YEC as they were too small.

LNG Facilities (Storage Tanks & Vapourizer)

Please see responses to YCS/LE-YEC-1-19 and YCS/LE-YEC-1-22.

An EPC tender for LNG truck offloading, storage and vapourizing equipment was issued in early October 2013 (see Attachment 1) and closed in November 2013. Only two bids were received. One bid was received after the RFP tender had closed and was consequently disqualified. The qualifying bid was over $4 million higher than the budgeted cost with contingency for this Project component. In light of the tender results, a decision was made to cancel the tender process, open the second bid package and negotiate directly with two potential suppliers.

The resulting information on the two bids indicated that both bids were similarly well above the budgeted cost - and only the non-disqualified bidder demonstrated a team with LNG experience, an adequate understanding of the project scope, and potential ability to meet the schedule requirements, as well as a lower cost estimate once each estimate was adjusted for contingency and risk.

During this review process of the two bids received YEC also considered contacting other potential suppliers who had previously shown some interest to provide the

components; however, a full cycle of negotiation and contracting was expected to add another 6-8 weeks and the RFP/tender process had failed to confirm other potential vendors willing to meet YEC's schedule and other requirements. In order to maintain the Project schedule, YEC needed to order tanks in particular by approximately end of November.

After further discussion and review with the non-disqualified bidder, it was determined that the most cost effective solution would be a contract negotiated directly with the subcontractor having the demonstrated experience as a provider of LNG fueling stations (GP Strategies) - and to contract with GP Strategies for supply of the LNG equipment other than the LNG storage tanks.

It was determined that YEC would itself procure three LNG storage tanks (each with approximate 166.5m^3 net capacity) in order to ensure tanks were ordered in time to maintain Project schedule. YEC reviewed LNG tanks proposals from Hitachi (had been included in the non-disqualified bid), CVA and Taylor Wharton (a separate established supplier recommended by GP Strategies). After comparison of the available information submitted by each of these three potential suppliers as regards schedule and costs (as well as ability to meet technical specifications), a decision was made to procure tanks from Taylor Wharton. A letter of intent was issued dated December 13, 2013 to Taylor Wharton for purchase of three LNG storage vessels, thereby protecting the schedule to have the three tanks delivered to the site no later than mid-September 2014.

Pricing and names of the bidders are confidential information with respect to YEC bidding process and policy. If the YUB wishes to view this information on a confidential basis it can be made available to the YUB.

YUKON ENERGY

YUKON ENERGY CORPORATION

REQUEST FOR PROPOSALS ("RFP") #2013-032

WHITEHORSE DIESEL-NATURAL GAS CONVERSION PROJECT AT WHITEHORSE, YUKON

ENGINEERING PROCUREMENT AND CONSTRUCTION CONTRACT

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TABLE OF CONTENTS

SECTION 1 INTRODUCTION AND DEFINITIONS 4

1.1 CORPORATE OVERVIEW 4
1.2 PURPOSE 4
1.3 INTENT 4
1.4 ACKNOWLEDGMENT 4
1.5 DEFINITIONS 5
1.6 INTERPRETATION 6
1.7 INDUSTRY MEANINGS 6

SECTION 2 INSTRUCTIONS TO PROPONENTS 7

2.1 PROPOSAL DELIVERY 7
2.2 CORPORATION'S DESIGNATE 7
2.3 CLOSING DATE AND TIME 7
2.4 PROPOSAL SUBMISSION 7
2.5 ELECTRONIC PROPOSAL SUBMISSION 8
2.6 VERIFICATION OF PROPOSAL RECEIPT 9
2.7 LETTER OF INTENT TO RESPOND 9
2.8 QUESTIONS AND QUERIES 9
2.9 PROPOSAL WITHDRAWALS 10
2.10 PROPOSAL AMENDMENTS 10
2.11 PROPOSAL DETAILS 10
2.12 ALTERNATIVE PROPOSALS 10
2.13 PROPOSAL OPENING 10
2.14 ADDENDA 11
2.15 EXTENSIONS 11
2.16 IRREVOCABILITY 11
2.17 REFERENCES / SEARCHES / CONTACTS 11
2.18 JOINT PROPOSALS 11
2.19 MATERIAL ADVERSE CHANGES 11
2.20 OPTIONAL SITE VISIT 12
2.21 MANUFACTURER'S BRAND NAMES 12

SECTION 3 EVALUATION PROCESS AND CRITERIA 13

3.1 EVALUATION COMMITTEE 13
3.2 EVALUATION METHODOLOGY AND PROCESS 13
3.3 VERIFICATION 13
3.4 RIGHT TO CLARIFY 13
3.5 PROPONENT INTERVIEWS 14
3.6 PROPONENT PRESENTATIONS 14
3.7 EVALUATION CRITERIA 14
3.8 SELECTION OF PREFERRED PROPONENT 15
3.9 EXECUTION OF CONTRACT 15
3.10 AUTHORIZATIONS AND APPROVALS 15
3.11 DEBRIEFING WITH UNSUCCESSFUL PROPONENTS 15
3.12 ALTERNATE PROPOSALS 16

SECTION 4 SUBMISSION REQUIREMENTS 17

4.1 GENERAL 17
4.2 EXECUTIVE SUMMARY 17

4.3 PROPONENT INFORMATION 17
4.4 PROPONENT CREDENTIALS 17
4.5 PROPONENT QUALIFICATIONS 19
4.6 FINANCIAL / BUSINESS PROFILE 19
4.7 REFERENCES 20
4.8 SPECIFIC REQUIREMENTS 20

SECTION 5 GENERAL CONDITIONS 22

5.1 CONFIDENTIAL AND PROPRIETARY INFORMATION 22
5.2 PROPONENT'S RESPONSIBILITIES 22
5.3 OWNERSHIP OF RFP DOCUMENTS 22
5.4 CONFIDENTIALITY 22
5.5 FULL DISCLOSURE 22
5.6 NO COLLUSION 23
5.7 RIGHT OF ACCEPTANCE / REJECTION 23
5.8 LIMITATION OF LIABILITY AND INDEMNITY 24
5.9 WAIVER OF IRREGULARITIES 24
5.10 NEGOTIATIONS 24
5.11 INCURRED COSTS / EXPENSES 24
5.12 INSURANCE [NTD: TO BE DISCUSSED] 25
5.13 KNOWLEDGE OF WORK AND SITE CONDITIONS 25
5.14 CONTRACT SECURITY 25
5.15 LEGAL COUNSEL 25

SECTION 6 FORMS OF PROPOSAL 27

6.1 ADDENDA AND QUESTION AND ANSWER ACKNOWLEDGEMENT 27
6.2 PROPOSAL FORM 28
6.3 CONTRACT PRICE 31
6.4 EXPERIENCE IN SIMILAR WORK 32
6.5 CONFLICT OF INTEREST; FULL DISCLOSURE 34

APPENDICES

APPENDIX A Letter of Intent to respond
APPENDIX B Specifications
APPENDIX C EPC Contract
APPENDIX D Basis of Design
APPENDIX E Process Flow Diagrams and Piping and Instrumentation Diagrams
APPENDIX F Data Sheets
APPENDIX G Site Layout
APPENDIX H Sample Fuel Specification
APPENDIX I 2010 National Building Code Seismic Hazard Calculation
APPENDIX J City Of Whitehorse Thermistor Data
APPENDIX K YEC Health And Safety Policy And Environmental Policy
APPENDIX L YEC Jobsite Spill Response Plan
APPENDIX M Yukon Oil And Gas Act
APPENDIX N Yukon Oil And Gas Regulations

SECTION 1 INTRODUCTION AND DEFINITIONS

1.1 CORPORATE OVERVIEW

Established in 1987, Yukon Energy Corporation ("the Corporation") is a publicly-owned electrical utility that operates as a business, at arm's length from the Yukon Government. We are the main generator and a transmitter of electrical energy in the Yukon and we work with our parent company Yukon Development Corporation to provide Yukon residents with a sufficient supply of safe, reliable electricity and related energy services.

The Corporation is regulated by the Business Corporations Act, the Public Utilities Act and the Yukon Water Act. The main office is located near the Whitehorse Rapids Hydro Plant in Whitehorse with community offices in Mayo, Faro and Dawson City.

Additional Corporation information and annual reports can be viewed on the Corporation's website at: http://www.yukonenergy.ca

1.2 PURPOSE

The Corporation is inviting Proposals from qualified proponents for Engineering, Procurement, and Construction (EPC) services for development of the Whitehorse LNG storage and vaporization facility (the "Facility"). The Facility will consist of truck off-loading facilities, gas storage tanks, send-out pumps, vaporization equipment, vapor handling systems and all auxiliary systems to be utilized to provide natural gas to two modular natural gas gen-sets. The construction work is scheduled for the 2014 construction season, to be substantially completed by October 14, 2013

1.3 INTENT

It is the intent of the Corporation to obtain the best overall solution, services and value through a RFP process that provides a high level of responsiveness, quality Proposals, and a Proponent that has a proven track record of meeting its client's needs.

Your company is invited to submit a Proposal on a competitive basis in the format described in these RFP documents. This RFP establishes requirements and defines responsibilities of the Proponent to carry out the engineering, procurement and construction in relation to the Facility.

The following schedule of key deadlines is provided for Proponents' reference:

(a) The scheduled start date of the Work is expected to be within 30 days following award of a Contract to the successful Proponent.

(b) The Guaranteed Completion Date should be no later than October 14, 2014.

(c) The final report due should be no later than 30 days after completion of the Work.

(d) The Work will be performed at Whitehorse, Yukon.

1.4 ACKNOWLEDGMENT

The Corporation thanks all Proponents for responding to this RFP. It recognizes the time, resources and energy that it takes to complete and submit a Proposal for consideration. The Corporation does not take lightly the endeavour and effort made to provide a Proposal and appreciates your response to this RFP.

In no way or manner should this RFP be considered a repudiation or statement of dissatisfaction with any current company providing services to the Corporation. This RFP is an ongoing business commitment and demonstration ensuring that the Corporation undergoes scrutiny and diligence that can withstand review and audit. The Corporation is committed to the highest standards of business practice and services and appreciates your company helping the Corporation achieve these goals.

Thank you in advance for participating in this RFP process.

1.5 DEFINITIONS

"Alternate Proposals" has the meaning set out in Section 2.12.

"Claim" means any claim, demand, suit, action or cause of action pursuant to contract, tort, statutory duty, law, equity, any actual or implied duty of fairness, or otherwise, and all costs and expenses relating thereto.

Closing Time" or **"Closing Date and Time"** means the date and time specified in 2.4 of this RFP.

"Contract" means the agreement between the Corporation and Contractor, to be substantially in the form set out in Appendix 3.

"**Contractor**" means the successful Proponent that is awarded a Contract as a result of this RFP process.

"Corporation" means Yukon Energy Corporation.

"Corporation's Designate" means the person named in this RFP who has the authority to issue the RFP and manage the RFP process on behalf of the Corporation.

"**Day**" means a calendar day, unless specifically stated otherwise.

"Facility" has the meaning given in Section 1.2.

"Forms of Proposal" means the forms set out in Section 6.

"Letter of Intent to Respond" means the form set out in Appendix A.

"Liability" means any costs, expenses, claims, losses (including loss of anticipated profits) incurred or suffered by any Proponent as a result of or related to this RFP, the preparation of a Proposal, the evaluation of Proposals, acceptance or rejection of any compliant or non-compliant Proposal (including the rejection of all Proposals by the Corporation), a breach of any obligations arising under this RFP, negotiations for a Contract or the cancellation, suspension or termination of the RFP process or any other matter related to this RFP or the RFP process.

"LNG" means liquefied natural gas.

"Potential Proponent" means a person or organization who has received this RFP.

"Project Site" means the site described in Appendix B.

"Proponent" means a person or organization who submits a Proposal in response to this RFP.

"**Proposal**" means the documents, if any, that Proponent delivers to the Corporation proposing to perform the Work.

"Proposal Delivery Office" means the Corporation office where Proposals shall be delivered, if by post or courier, as specified 'Proposal Delivery' of this RFP.

"RFP" means this Request for Proposal process.

"RFP Documents" means all sections of this RFP, the addenda, if any and the question and answer series, if any.

"Specifications" means the specifications for the Work set out in Appendix B.

"**Work**" means all or any part of the services and obligations required to be performed by the Contractor under the Contract, as further defined in Appendix B.

1.6 INTERPRETATION

In this RFP, unless the context requires otherwise:

(a) headings are for convenience only and do not affect interpretation;

(b) words in the singular include the plural and vice versa;

(c) a reference to "includes" or "including" means "includes, without limitation" or "including, without limitation", respectively;

(d) a reference to "person" means an individual, partnership, consortium, corporation, joint venture or other entity or a government or any agency, department or instrumentality thereof and vice-versa; and

(e) a reference to a determination to be made by the Corporation, or the right of the Corporation to take or not take a particular action or to make or not to make a particular decision or determination means that the Corporation will be entitled to take such an action or to make such a decision or determination, in its sole and absolute discretion.

1.7 INDUSTRY MEANINGS

Words and phrases used in this RFP that are not expressly defined in this RFP and that have acquired special meanings as generally known in the construction and LNG industries will be given such special meanings.

SECTION 2 INSTRUCTIONS TO PROPONENTS

Proponents should complete the Forms of Proposal and provide comprehensive information as outlined in the RFP Documents to enable complete and accurate evaluation of their Proposal. Omission of any information that the Corporation deems as pertinent to a Proposal may cause the Proposal to receive a lower rating through evaluations, or may cause the Proposal to be disqualified at the Corporation's absolute discretion.

2.1 PROPOSAL DELIVERY

Proposals along with the submission documents in the Forms of Proposal section should be submitted in a sealed envelope and delivered in original form by hand or courier to:

Yukon Energy Corporation
Attention: Matthew Sills
Procurement Department
2 Miles Canyon Rd
Whitehorse YT Y1A6S7

2.2 CORPORATION'S DESIGNATE

For the purposes of this RFP process, the Corporation's Designate is:

Matthew Sills
phone: 867-393-5335
matthew.sills@yec.yk.ca

E-mail communications are preferable.

2.3 CLOSING DATE AND TIME

The date and time of RFP closing is **October 28, 2013 at 4:00:00 p.m. PST** (as per the Corporation's time clock located at the reception area). Strict adherence to this deadline will be maintained. In order to be considered, Proposals must be received at the location specified herein on or before the RFP Closing Date and Time. Proposals received after the Closing Date and Time will be rejected and returned to the Proponent unopened.

Proposals submitted electronically under Section 2.5 shall be deemed to have been delivered after the Closing Date and Time if the transmission of the Proposal begins before the Closing Date and Time but is not completed until after the Closing Date and Time. The time for electronic delivery shall be determined by reference to the Corporation's computer server.

2.4 PROPOSAL SUBMISSION

Proponent should clearly identify on the envelope containing the Proposal, the name and address of the Proponent, the RFP number, the title of the RFP and the RFP Closing Date and Time.

Three (3) copies of the Proposal should be submitted. The first copy should be in hardcopy form, and be originally executed including original signature(s) of duly authorized signatory(s) of the Proponent.

One copy of all Pricing Pages, as outlined in the Forms of Proposal should be submitted in a separate envelope, identified with the name and address of the Proponent, the RFP number, the title of the RFP, and labelled:

Confidential
Pricing Pages

One copy of the Proposal, in electronic form, preferably on a CD or DVD, should be included as part of the Proposal submission package.

Proposals submitted via fax or other non-original formats, other than in accordance with Section 2.5, will not be accepted without the prior written consent of the Corporation's Designate.

To enable the Corporation to effectively evaluate submissions, Proponents are requested to submit Proposals with adherence to the form and format within these RFP Documents, referencing the section(s) and clause(s), as necessary, to facilitate accurate and expedient evaluations.

2.5 ELECTRONIC PROPOSAL SUBMISSION

The Corporation will accept Proposals in electronic format, in accordance with this Section 2.5. If submitting your Proposal electronically, and in order for your Proposal to be considered, your Proposal must:

(a) be identified and transmitted using two separate emails as follows:

  (i) email 1 will be sent to tenderform1@yec.yk.ca and will consist of Proposal Form 1 and all information other than Proposal Form 2 and other pricing information and should be identified on the subject line as "Submission for RFP #2013-032, Proposal Form 1"; and

  (ii) email 2 will be sent to tenderform2@yec.yk.ca and will consist of Proposal Form 2 and any associated pricing information and should be identified on the subject line as "Submission for RFP #2013-032, Proposal Form 2";

(b) also be delivered in hard copy form to arrive as soon as possible after the Closing Date and Time and email 1 must include shipment/courier details to assure the Corporation that the originally executed Proposal documents are in transit, including;

  (i) the name of the courier company by which the original Proposal documents have been shipped; and

  (ii) the courier company's document tracking number(s).

If there are discrepancies between the Proposal as submitted electronically and the hard copy Proposal received subsequently, the hard copy Proposal shall govern.

Proponent's sales literature and/or any information additional to that requested in this RFP, that the Proponent is including in its Proposal, need not be included in the electronic Proposal submission, but should be included in the hard copy submission.

Proponents should note that it is their responsibility to ensure that electronic transmissions are free from all viruses. If the Corporation receives an electronic transmission that is infected with a virus or other electronic code that, in the sole opinion of the Corporation, is harmful to the Corporation's computer systems, the Corporation reserves the right to take any action as deemed necessary to disinfect the electronic transmission. The Corporation will not be liable for any changes that may occur to the electronic transmission, including rendering the transmission unreadable, as a result of the disinfecting process.

Proponents should note that the Corporation's email system will not accept emails in excess of 10 MB. In the event that theProponents submission is in excess of 10 MB, the proponent may submit in multiple emails, clearly identifying the emails per Sections 2.5.A.i and ii above as email 1 of 2, 2of 2 etc. The Corporation prefers all attachments to be in PDF format. It is the responsibility of Proponents to ensure that emails are of a size that can be received by the Corporation and in a format that can be read by the Corporation.

The Corporation is not responsible for, and the Proponent assumes all the risks associated with, the receipt of and/or confidentiality of any documents delivered by electronic submission.

The Corporation is not responsible for, and the Proponent assumes all the risks associated with, the electronic submission of documents including, but not limited to:

A. receipt of a garbled or incomplete document(s);

B. lack of access to or availability of the receiving equipment;

C. defective receiving equipment;

D. incompatibility between sending and receiving equipment;

E. delay or interruption in transmission or receipt of the transmitted document(s); and

F. illegibility of all or any part of the document(s).

2.6 VERIFICATION OF PROPOSAL RECEIPT

Proponents may verify that their Proposal has been received prior to the Closing Date and Time by contacting the Corporation's Designate. The Proponent must identify their company name before any information will be released. No other information concerning the RFP other than confirmation of Proposal receipt will be released.

2.7 LETTER OF INTENT TO RESPOND

Proponents should complete and sign the Letter of Intent to Respond and email it to the Corporation's Designate at matthew.sills@yec.yk.ca, in order to be registered to receive any subsequent information regarding this RFP, including any addendum to this RFP, and the results of questions and answers. The Corporation assumes no responsibility for ensuring Proponents are sent subsequent information if the Letter of Intent to Respond is not submitted.

2.8 QUESTIONS AND QUERIES

Proponents are required to submit their questions or requests for clarification, including questions or clarifications relating to specifications, discrepancies, omissions or any apparent ambiguities, in writing, by email to the Corporate Designate, as per the schedule below.

The Corporation shall review the questions, and where the information is not already clearly provided, will issue either an addendum or a question and answer series to all Potential Proponents. The Proponent that submitted the question will not be identified in the Corporation's response.

Proponents shall not contact or ask questions of any other Corporation personnel unless so directed elsewhere in this RFP. Information obtained from any person or source other than the Corporation's Designate will not be considered valid to this RFP process and cannot be considered or incorporated into

the Proponent's Proposal. The Corporation reserves the right to disqualify any Proponent who solicits information from any person other than the Corporation's Designate.

	Submission Date	Corporation's Response Date
Q&A Session #1	October 11, 2013	October 15, 2013
Q&A Session #2	October 21, 20133	October 23, 2013

2.9 PROPOSAL WITHDRAWALS

Proposals may be withdrawn at any time prior to the Closing Date and Time by submitting a written withdrawal request to the Corporation's Designate at the same address to which the Proposal was submitted. The Proposal will be returned to the Proponent unopened.

2.10 PROPOSAL AMENDMENTS

Where a Proposal has been received by the Corporation before the RFP Closing Date and Time, amendments by email are acceptable provided that such amendments are received in writing at the location specified herein prior to the RFP Closing Date and Time.

Amendments to Proposals should clearly state the name and address of the Proponent, the RFP number, and the name of the RFP in accordance with these Instructions to Proponents. Any amendment must be duly signed by an authorized signatory of the Proponent.

Any amendment to the Proposal price should state only the amount by which the Proposal price is increased or decreased and should not indicate the revised total Proposal price.

2.11 PROPOSAL DETAILS

Proponents should provide complete and accurate information and details for all aspects of their Proposal. Failure to respond to any requests for information, costs, qualifications or clauses will be deemed to be a negative response and may disqualify the Proposal or cause the Proposal to receive a lower rating through evaluations.

2.12 ALTERNATIVE PROPOSALS

Proponents wishing to submit alternate innovative methods or operational Proposals ("Alternate Proposals") that they feel will benefit the Corporation are encouraged to do so. It is requested that Alternate Proposals be submitted separately and identified as an 'Alternate Proposal'. In order to have an Alternate proposal considered, Proponents must submit a base proposal that meets the service requirements stated in this RFP. It is also requested that Proponents identify their preference of alternatives in order from first preference on.

2.13 PROPOSAL OPENING

The opening of Proposals will be closed to the public. Information on Proponent's names and/or prices received may be released at the Corporation's absolute discretion. In the event the Proponent's names and/or prices are released, this information may be released in a timely fashion after Proposals are opened and evaluated, and a Contract is awarded to the successful Proponent.

2.14 ADDENDA

All addenda and/or question and answer series issued during this RFP will become part of the RFP. Proponents should identify all addenda and/or question and answer series received during the RFP process as requested in the Forms of Proposal.

2.15 EXTENSIONS

The Corporation may extend the Closing Date and Time of the RFP by issuing a written addendum to all Potential Proponents.

2.16 IRREVOCABILITY

Proposals shall be irrevocable for a period of ninety (90) days from the Closing Date and Time and the Proponent shall not have the option of revoking its Proposal until the expiry of the irrevocable period.

2.17 REFERENCES / SEARCHES / CONTACTS

Proponents are requested to include a list of at least three (3) references of clients, complete with the contact person(s) and their contact information, for which they have done work, similar in scope and size to the Work outlined in the RFP, within the past three (3) years.

Proponents, responding to this RFP, authorize the Corporation to contact any references (current and past), whether the reference was listed by the Proponent as one of the Proponent's references in the Forms of Proposal or not.

2.18 JOINT PROPOSALS

Proposals may be submitted where more than one company or organization will be performing the Work through a joint Proposal. In this case:

(a) All companies or organizations must be identified in the Proposal;

(b) The portion of the Work to be provided by each company or organization should be clearly identified;

(c) One company should be identified in the Proposal as the point of contact for the purposes of this RFP process, and the identified company will assume overall responsibility for the Work; and

(d) No other companies or organizations may be added or substituted without the prior written consent of the Corporation.

If a joint Proposal is submitted, the Forms of Proposal should be duly executed by all organizations to the joint venture.

2.19 MATERIAL ADVERSE CHANGES

Following the date the Proponent submits its Proposal, Proponents shall inform the Corporation immediately, via a Corporation's Designate, details of any material change to the information previously submitted by the Proponent.

The Corporation shall evaluate the information submitted by the Proponent in accordance with Section 3. In the event that a material adverse change is reported after the selection of a Preferred Proponent (regardless of whether the Proponent selected as such has been notified of the same), and the evaluation of the Proponent's Proposal, taking into consideration the material adverse change and applying the criteria described in Section 3, would result in the Proponent being ranked lower than a Proponent that had not been selected as the Preferred Proponent, the Corporation may select a different Preferred Proponent.

2.20 OPTIONAL SITE VISIT

The optional site visit is highly recommended and staff will be provided to assist Proponents in making an examination of the site prior to submitting their Proposals. The Corporation will provide a knowledgeable representative to provide details and to answer questions on a reasonable efforts basis during the site visit, but such verbal responses cannot be relied upon. Proponents are therefore strongly encouraged to submit all questions arising from the site visit in writing pursuant to Section 2.8. There is a question submission date scheduled for October 21, 2013, following the site visit. Proponents will be requested to sign an attendance form which will be provided at the location of the site visit. Proponents that do not attend the Site Visit will not be prohibited from submitting a Proposal. Attendees are requested to provide their own PPE (personal protective equipment) which consists of a high visibility vest, hardhat and protective footwear.

The optional site visit will be provided at the date, time and location as follows:

Yukon Energy Corporate Office
#2 Miles Canyon Road
Whitehorse Yukon
October 17th, 2013 at 1:00 PM

The Project Site is described in Appendix B. Proponents should advise the Corporation at the earliest opportunity if they feel that the Project Site is inadequate in any way.

Attendance at the site visit is permitted on the express condition that the Proponent indemnifies the Corporation against all liabilities in respect thereof, however caused, which but for the granting of such permission would not have arisen.

2.21 MANUFACTURER'S BRAND NAMES

The use of manufacturer's brand names or proprietary names in the RFP is for the sole purpose of providing a further detailed description of the materials or equipment for the purpose of indicating an acceptable standard of quality to the Corporation or for identifying an acceptable standard of compatibility. Proponents wishing to offer a substitute may do so without obtaining prior acceptance by the Corporation and the Proponent is solely responsible to ensure the equivalency or compatibility of the substitute.

SECTION 3 EVALUATION PROCESS AND CRITERIA

3.1 EVALUATION COMMITTEE

An evaluation committee comprised of Corporation staff will evaluate Proposals received. The Corporation reserves the right to include subject matter expert(s) and/or external consultant(s) as part of the evaluation committee, at the Corporation's absolute discretion.

3.2 EVALUATION METHODOLOGY AND PROCESS

Proposals will be evaluated on the information received in the Proposal, only if received by the Closing Date and Time. The evaluation committee will review each Proposal to ensure compliance with the requirements of the RFP. The committee will use specific evaluation criteria to rate the various components of the Proposals.

Proposals may be further evaluated on information received through the RFP process, including but not limited to clarifications, additional information, telephone conversations, Proponent presentations, interviews and/or meetings with short listed Proponents.

3.3 VERIFICATION

The Corporation reserves the right to verify any statement or claim contained in any Proposal or made subsequently in any interview or negotiation. Any such verification may be made by whatever means the Corporation deems appropriate and may include contacting the client references provided by the Proponent. The Corporation may also contact other parties that are not provided as references by the Proponent.

By submitting a Proposal, the Proponent is deemed to consent to the Corporation verifying any information from third parties including the Proponent's bank and receiving additional information relating to the Proponent, its directors, officers, shareholders or owners and any other person associated with the Proponent as the Corporation may require. The Corporation will not appoint a Preferred Proponent whose references, whether provided by the Proponent or obtained otherwise by the Corporation, are found, in the Corporation's opinion, to be unsatisfactory.

Any written information received by the Corporation from a Proponent pursuant to a request for clarification or further information may be considered, at the Corporation's discretion, an integral part of the applicable Proposal.

3.4 RIGHT TO CLARIFY

The Corporation reserves the right at any time to seek clarifications of, or any additional information in connection with, or modifications of any Proposal from any one or more Proponents, but not necessarily all Proponents, either consecutively or concurrently and in any manner including through verbal or written correspondence, interviews and/or presentations by Proponent(s).

Any clarifications, additional information or modifications received in connection with this RFP may form part of the RFP and may be considered by the Corporation in its absolute discretion in its evaluations and decisions including without limitation as to acceptance, rejection, negotiation or award, and the Corporation will be entitled to accept any Proposal as clarified, supplemented or amended through this process.

Such clarification (if any) is not intended to provide an opportunity for Proponents to change or amend their Proposal in any substantive manner.

3.5 PROPONENT INTERVIEWS

The Corporation reserves the right to conduct interviews at the Proponent's site as part of the evaluation process. The Corporation will not necessarily select any or all of the Proponents to take part in this process. Proponent(s) selected for interviews will be from a selection process through the evaluations and at the absolute discretion of the Corporation.

3.6 PROPONENT PRESENTATIONS

The Corporation reserves the right to request selected Proponent's to perform presentations as part of the evaluation process. The Corporation will not necessarily select any or all of the Proponents to take part in this process. Proponent(s) selected to perform presentations will be from a selection process through the evaluations and at the absolute discretion of the Corporation.

3.7 EVALUATION CRITERIA

For the purposes of Proposal evaluation, the Corporation may take into account, in its absolute discretion, any or all of the information received from the Proponent under or pursuant to the RFP Documents, the Corporation's knowledge of, and/or past experience with the Proponent (including the Proponent's performance on previous contracts with the Corporation, if any), and any information about the Proponent received from third parties and deemed reliable by the Corporation.

The Corporation has no obligation to inform Proponents of the details of its evaluation process, of the weight attached to any particular evaluation criterion, or of the specific ranking assigned to any evaluated Proposal.

Evaluation Criteria

(a) Proposed Methodology

(b) Previous Experience in Similar Work - Corporate

(c) Previous Experience in Similar Work (including northern experience) - Proposed Team

(e) Strength of Technical Proposal; including but not limited to Proponent and its subcontractors' ability to perform the Work, as applicable.

(f) References; references may include Proponent's references as well as any proposed subcontractors' references as applicable, and may include both external references as provided by the Proponent, and internal Corporation references.

(g) Commercial Credibility; including but not limited to financial ability, capacity and availability of resources, experience, reputation, track record of performance, conflict of interest concerns, and security.

(h) Cost; total overall cost to the Corporation;

(i) Environmental and Social Responsibility;

(j) Proposed Subcontractors; as applicable.

Following evaluation of Proposals, short listed Proponents may be further evaluated on the strength of their presentations, if presentations are held.

The Corporation anticipates awarding the Contract in November 2013.

3.8 SELECTION OF PREFERRED PROPONENT

After its evaluation of all of the Proposals, the Corporation will recommend a Preferred Proponent to the Corporation. The Preferred Proponent will be the Proponent whose proposal achieves the highest evaluation score. The Corporation will review and approve the results of the evaluation and authorize the project team to finalize the Contract with the Preferred Proponent.

3.9 EXECUTION OF CONTRACT

The Preferred Proponent shall execute the Contract, subject only to revision in respect of the following:

(a) minor changes, additions and modifications necessary to create a legally complete and binding agreement;

(b) changes, additions and modifications to those provisions which require;

(c) the insertion or addition of information relating to the Preferred Proponent's corporate and funding structure which are consistent with the principles set out in the Contract;

(d) the insertion or addition of information or the modification of provisions of the Contract required in order to reflect accurately the nature of the Preferred Proponent's relationships with its principal subcontractors, but not in such a way as to alter the risk allocation set out in the Contract; or

(e) changes, additions and modifications required in order to complete (based on the Proposal) any provision of the Contract (where contemplated in or required under the terms of the RFP) or to complete any Schedules to the Contract; and

(f) changes, additions and modifications to those parts of the Contract which are indicated in the Contract as being subject to completion or finalization;

provided that in each case the changes, additions or modifications are consistent with the principles set out in the Contract and otherwise acceptable to the Corporation.

The Preferred Proponent shall maintain its prices in accordance with the term and condition of this RFP subject only to revisions to such prices as explicitly agreed to by the Corporation.

3.10 AUTHORIZATIONS AND APPROVALS

Proponents acknowledge that the entering into of the Contract by the Corporation is conditional on and subject to the Corporation obtaining any necessary authorizations and approvals.

3.11 DEBRIEFING WITH UNSUCCESSFUL PROPONENTS

At the conclusion of the RFP process and following the execution of a Contract, an unsuccessful Proponent may request that the Corporation provide a debriefing at which the Corporation will generally explain the strengths and weaknesses of the Proposal. If a Proponent requests a debriefing:

(a) the debriefing will be between the Corporation and the Proponent requesting the debriefing;

(b) the debriefing will not include disclosure of specific scores for or ranking of the Proposal or details of any other Proposal; and

(c) the terms of this RFP will apply to the debriefing including, for the avoidance of doubt, the requirement that the Proponent treat all information received at a debriefing as confidential.

3.12 ALTERNATE PROPOSALS

The Corporation reserves the right, at its sole discretion, to consider or reject any Alternative Proposal. Alternative Proposals which are considered will be evaluated in accordance with the evaluation criteria set out in Section 3.7.

SECTION 4 SUBMISSION REQUIREMENTS

4.1 GENERAL

To provide the Corporation with complete information to enable comprehensive and accurate evaluation of the Proposals, Proponents will provide the information required by this Section 4 in their Proposal. Any additional information may be included at the Proponent's discretion. Omission of any information that the Corporation deems as pertinent to the Proposal may cause the Proposal to be rejected in the Corporation's sole discretion. Any supporting documentation such as personnel résumés should be attached as appendices and cross-referenced to the appropriate section of the Proposal.

The successful Proponent shall be responsible for supplying all labour, supervision, construction equipment, tools, installed materials and equipment, consumables and temporary facilities necessary to perform the Work in accordance with the Contract and to provide a complete Facility meeting with the Specifications.

4.2 EXECUTIVE SUMMARY

Proponents will include an Executive Summary of the key features of their Proposal which will include a brief description outlining how the Proponent considers itself to be uniquely capable of satisfying the Corporation's requirements as set out in this RFP and the key strengths it will bring to the successful completion of the Project.

4.3 PROPONENT INFORMATION

Proponents will provide the following information:

(a) general company overview, if applicable;

(b) principal owners and senior executives;

(c) years in operation; and

(d) management and operating strategy.

In the case of a Proposal submitted by a joint venture or other association of two or more companies, a copy of the joint venture agreement or documentation evidencing the association shall be provided with the Proposal. Proponents are referred to Section 2.18 of this RFP for further information.

4.4 PROPONENT CREDENTIALS

(a) General Competency and Capacity

Proponents will provide the following information:

(i) technical and equipment resources available for assignment to the Project;

(ii) current and pending projects, including status, size and estimated time of completion in relationship to the Proponent's total workload;

(iii) ability to meet the demands, needs and timelines of the Project in relation to current ongoing and pending projects;

(iv) methodology and approach to understanding the goals and needs of the Corporation and the challenge and design objectives of the Project;

(v) understanding of the construction environment in the Yukon;

(vi) any special reasons why the Proponent wishes to undertake the Project; and

(vii) details of local Canadian participation - the Proposal shall identify the planned number of workers on site by month and the percentage of which are planned to be Canadian.

(b) Liquefied Natural Gas Facility Design and Construction Experience

The Proponent will:

(i) list any experience in Liquefied Natural Gas Facility Design and Construction Projects or other projects of similar scope completed in the last ten (10) years; and

(ii) provide details of each project, including the Proponent's role, project size, value, duration, and date completed.

(c) Project Team

The Proponent will:

(i) outline the project team that will be assigned to the Project and the availability and commitment of each individual, including the leader or leaders of the team. How many projects with similar role and scope have discipline leads completed?

(ii) list all members, their individual roles, their expected involvement for the duration of the Project and education, general experience and overall project and scale experience (résumés for key members, including resumes of the Proponent's key nominees for each of the positions indicated in Schedule P to the Contract, must be attached to Proposals). Where key members of the team are not employees of the Proponent, details of their contractual relationship to the Proponent must be supplied;

(iii) list the benefits that the team can provide to the Corporation and this Project;

(iv) list those core team members who have worked together on a liquefied natural gas project or comparable project and outline their respective roles; and

(v) define how the team will be organizationally structured (an organizational chart is recommended).

(d) Subcontractors

The Proponent will provide a list of subcontractors proposed to be used, including details of the portions of the Work proposed to be subcontracted. Full details of the subcontracting arrangements must be provided, including a summary of the key terms of the subcontracts.

4.5 PROPONENT QUALIFICATIONS

The following outlines the qualifications the Proponent should present in order to be considered qualified to perform the Work. The qualifications identified herein are not all inclusive; it will be the Contractor's responsibility to ensure the workers and equipment are adequately and properly qualified to perform the Work.

(a) Proponents should demonstrate a clear understanding of and experience with the codes and standards that apply to Liquefied Natural Gas facilities; Proponents should demonstrate a clear understanding of and experience with the components associated with the transport, offloading, storage and vaporization of liquefied natural gas;

(b) Proponents should demonstrate a clear understanding of and experience with building infrastructure in a cold climate environment;

(c) Proponents are requested to provide clear evidence of their proposed team's ability to perform the Work;

(d) Proponents are requested to provide clear evidence of their firm's ability to do the Work; and

(e) Proponents are requested to provide clear evidence of their firms and more importantly the project team's skills and expertise to perform the Work.

Proponents are requested to describe their proposed approach to managing this Project, including but not limited to:

(i) provide evidence of a clear understanding of project purpose, background, and requirements;

(ii) provide evidence ability to quickly identify issues and provide pertinent, cost-effective recommendations

Proponents are requested to advise their availability to perform the Work starting as soon as possible in 2013 and to complete the Work in the time frame indicated in this RFP.

4.6 FINANCIAL / BUSINESS PROFILE

The Proponent will have a sound financial and business profile and the resources to successfully undertake and complete the Work. The Proponent will:

(a) provide information regarding the firm's or the individual's financial institution, insurance company, policy details and limits;

(b) provide details of any outstanding claims or lawsuits against the Proponent that may materially impact on the firm's ability to perform the Work;

(c) provide information regarding the Proponent's Workers' Compensation, Health and Safety Board coverage and Occupational Health and Safety policies; and

(d) provide additional information regarding any other certifications received by the Proponent.

(e) provide most recent financial statements for Proponent, including financial statements of parent company if the Proponent is a wholly owned subsidiary

Where the Proponent or a member of a joint venture Proponent is a subsidiary company, it shall submit the name and address of its ultimate parent company.

4.7 REFERENCES

The Proponent will provide client references (current or past) and contact information in relation to its abilities and references for the lead individuals and key personnel of the team for the following:

(a) liquefied natural gas facility construction or related projects completed or underway; and

(b) other major projects completed or underway utilizing an EPC approach.

Proponents will provide the company name of the reference, contact information (telephone, fax and e-mail), the position of the reference contact, and the date when the work was completed.

4.8 SPECIFIC REQUIREMENTS

(a) General

(i) Proponents shall supply a project schedule. The project schedule shall contain approximately 25 events and integrate with the following durations and milestones

A. Schedule references in Schedule C to the Contract.

B. Required dated for all interface points defined in Schedule E to the Contract.

(ii) Proponents shall provide a list of activities that they will undertake during the first 45 days of the Work to ensure the Corporation that the required plans and procedures are in place to quickly and efficiently start work, one released.

(iii) Proposals shall provide information regarding the location where all phases of the work will be performed and the logistics that the Proponent will establish for the completion of the Work.

(iv) In the proposal, the Proponent shall provide an overview of its Project Execution Plan, which includes their plans to execute all phases of the Work, including information on the vendor drawing review cycle.

(b) Engineering

(i) The Proponent shall state what design software will be used on this Project by the various engineering disciplines, as well as the Project controls programs.

(ii) The P&IDs provided in this RFP are provided to define the minimum requirements of equipment, instrumentation, valving, relief, bypasses, etc. If the Proponent feels that it has P&IDs that are more cost-effective or otherwise superior, then it may propose its P&IDs.

(c) Procurement

The Proponent shall provide a sample of the procurement status tracking documents in the Proposal.

(d) Construction

The Proponent shall provide its recent safety performance history with its Proposal.

SECTION 5 GENERAL CONDITIONS

5.1 CONFIDENTIAL AND PROPRIETARY INFORMATION

This RFP is the property of the Corporation and Proponents and/or any persons who have obtained a copy of the RFP shall keep confidential and shall not use, reproduce or distribute any information, drawings or specifications included in or provided with the RFP except for the purpose of preparing a Proposal for the RFP.

The Corporation shall comply with all applicable privacy laws in respect to any Proposal received in response to this RFP. Proponents shall clearly identify any information and/or records that it is providing in its Proposal that constitutes confidential information that is supplied in strict confidence and/or the release of which could significantly harm them.

5.2 PROPONENT'S RESPONSIBILITIES

If the Corporation accepts a Proposal, the Proponent will be bound by the RFP Documents, the Proponent's Proposal, the General Conditions, the Special Conditions if any, and any subsequent negotiations and will commence the Work within the time specified, and will complete all the Work by the date for substantial performance of the Work, as per the Contract.

5.3 OWNERSHIP OF RFP DOCUMENTS

All Proposals including any documents submitted to the Corporation by a Proponent as part of this RFP process, and any subsequent Contract, become the property of the Corporation and shall not be returned to Proponent.

5.4 CONFIDENTIALITY

The Proponent shall not publish any statement in any paper or document or issue any press release or make any public announcement or disclosure concerning the RFP, the Proposal or the award of the Contract without the prior written consent of the Corporation, which consent may be unreasonably withheld, except as required by law.

5.5 FULL DISCLOSURE

Proponents are to provide a written statement of full disclosure as outlined in the Forms of Proposal, addressing the following particulars:

(a) Any personal relationship to any employee of the Corporation who makes recommendations concerning the award of the Contract contemplated within this RFP or any employee (or immediate relative of an employee) of the Corporation with any direct or indirect pecuniary interest, ownership or directorship with respect to the Proponent;

(b) Any business relationship with the Corporation, any of its staff, employees, officers, directors or board members;

(c) Any matter involving a dispute with a claimed value in excess of $50,000 which is the subject of any current, pending or threatened mediation, arbitration or litigation proceeding; and

(d) Any proceedings involving the Proponent under the *Bankruptcy and Insolvency Act* (Canada), the *Companies Creditor Arrangement Act* (Canada) or similar legislation.

Proponents should specifically address the requirements of this section by either providing appropriate disclosure or by indicating that they have nothing to disclose in respect of the matters listed above.

Proponents must advise the Corporation of any change in the foregoing throughout the RFP process or intended negotiation period.

The Corporation reserves the absolute right to eliminate any Proposal or terminate any resulting Contract(s) without prejudice for failure to disclose the information required herein and/or for disclosure at any time of proceedings in the nature of bankruptcy or insolvency by or against the Proponent.

5.6 NO COLLUSION

Proponents shall not discuss or communicate, in any form, with any other Proponent or any representative or agent of any other Proponent regarding the preparation and/or presentation of their Proposal. Proposals shall be submitted without any connection, knowledge, comparison of information or arrangement with any other Proponent or any agent or representative of any other Proponent.

If a Proponent contemplates using the same subcontractor or supplier for a particular part of the deliverables, the Proponent shall put into place appropriate ethical walls and other safeguards to protect the confidentiality of their information and to ensure collusion does not take place.

5.7 RIGHT OF ACCEPTANCE / REJECTION

The Corporation, at its absolute discretion, reserves the right at any time prior to selection of the successful Proponent(s), to accept in whole or in part all Proposals it has received, to withdraw any portion of this RFP and/or to cancel it in its entirety. Upon evaluation of all valid Proposals received, the Corporation will select the Proposal which offers the most effective and beneficial package. The Corporation reserves the right to award the Work to one or more Proponents. The lowest priced or any Proposal will not necessarily be accepted. No act of the Corporation, other than a notice in writing signed by a Corporation's Designate, shall constitute an acceptance of a Proposal. In the event that all Proposals exceed the budget set by the Corporation, the Corporation reserves the right not to accept any Proposals and to close the RFP process without award. Thereafter, the Corporation may re-tender, sole source to any vendor, including any Proponent(s) that submitted a response to this RFP or a vendor that did not submit a response to this RFP, or do nothing.

From the information submitted under this RFP, the Corporation shall determine the Proposal(s), which in the sole judgment of the Corporation, provides the best value to the Corporation in accordance with the requirements and criteria set out in this RFP. Further, the selection of the successful Proposal(s) will be made on the basis of the Proposal(s) which meets the Corporation's needs and any requirements, specifications, deliverable, scope of work and/or any other criteria of this RFP including any addenda or memoranda.

This RFP should not be construed as an agreement for the identified Work. The Corporation is not bound to enter into a Contract with the Proponent that submits the lowest price and/or fee structure or with any Proponent. Proposals will be assessed and evaluated in accordance with the evaluation criteria. The Corporation is under no obligation to receive further information, whether it is oral or written, from any Proponent.

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5.8 LIMITATION OF LIABILITY AND INDEMNITY

Each Proponent expressly agrees that:

(a) it will not bring any Claim against the Corporation, or any of its employees, contractors, consultants or agents, for any Liability in excess of the lesser of an amount equivalent to the reasonable costs incurred by the Proponent in preparing its Proposal and $50,000;

(b) it waives and releases any and all Claims against the Corporation and its employees, contractors, consultants and agents, for any loss of anticipated profits; and

(c) the Proponent will indemnify and hold the Corporation and its employees, contractors, consultants and agents harmless against any and all Claims for Liability brought against any one or more of them by third parties where such third parties were directly or indirectly engaged by or through the Proponent in connection with this RFP.

5.9 WAIVER OF IRREGULARITIES

The Corporation reserves the right to and may waive any irregularity(s) or non-compliances within Proposals received, at the Corporation's absolute discretion. Failure to comply with any requirement(s) of this RFP may be deemed sufficient cause to reject all or part of any Proposal, at the Corporation's absolute discretion.

5.10 NEGOTIATIONS

Notwithstanding any other provision in this RFP, the Corporation reserves the right in its sole and absolute discretion at any time and from time to time after submission of Proposals and before award of a Contract to negotiate any or all terms and conditions of a Contract or otherwise in respect of the Work for which a Contract may be awarded, including negotiating terms and conditions that are or may be different from those contained in the RFP, with one or more Proponents but not necessarily with all Proponents. The Corporation also reserves the right not to enter into negotiations with one or more Proponents, to terminate negotiations with any Proponent(s), not to offer the same or substantially the same negotiated terms and conditions of a Contract to more than one Proponent and to award a Contract by acceptance of any Proposal so negotiated.

5.11 INCURRED COSTS / EXPENSES

Proponents are solely responsible for their own costs and expenses in preparing and submitting their Proposal and for any subsequent negotiation costs and expenses with the Corporation, if any.

If the Corporation elects to cancel this RFP or rejects all Proposals received, the Corporation will not be liable to any Proponent for any costs or expenses of preparation and/or presentation of its Proposal.

The Corporation will not be liable to any Proponent for any claims, whether for costs, expenses or damages incurred by a Proponent in preparing its Proposal, loss of anticipated profits in connection with any final Contract or any other matter relating to this RFP process whatsoever.

By submitting a Proposal, the Proponent agrees that it will not claim damages, for whatever reason, relating to the RFP or in respect of the competitive process and agrees that it will waive any claim for loss of profits if no Contract is entered into with the Proponent.

5.12 INSURANCE

Before commencing the Work, Contractor shall obtain and maintain the insurance policies in accordance with the Contract:

5.13 KNOWLEDGE OF WORK AND SITE CONDITIONS

It is the Proponent's sole responsibility to fully inform itself of the Work and site conditions prior to submitting a Proposal. The Proponent is responsible to familiarize itself with the site and all conditions thereon and to have made all investigations necessary to obtain a full understanding as to the form and nature of the site, ground, quantities, location, nature and conditions of the Work, site access, accommodation and facility requirements, the conditions under which the labour force will be employed and any risks associated with the Work. The Proponent will, in general, have obtained all necessary information, local or otherwise, as to risks, contingencies and other circumstances which may influence or affect its Proposal.

It is the Proponent's sole responsibility to fully inform itself of all aspects of the Work prior to submitting a Proposal. No allowance will be made by the Corporation for failure of the Proponent to ensure it has a comprehensive understanding of all aspects of the Work, and the Corporation shall not be liable to Proponents for any misunderstanding on behalf of Proponents as to the nature and scope of the Work and/or any associated risks and conditions relating to the Work. Proponent's failure to perform an examination of the site or to fully inform itself of site conditions shall not relieve the Proponent of its responsibility to satisfactorily perform the Work if awarded a Contract.

5.14 CONTRACT SECURITY

The Proponent is advised that, if awarded the Contract, within fourteen (14) days of the award of the Contract, or within any further period permitted by the Corporation, the Contractor may be required to deliver to the Corporation the following Contract Security:

(a) where required by the Corporation in its absolute discretion before or after the Contract is awarded, an executed guarantee from its parent company;

(b) a performance bond in the amount of fifty percent (50%) of the total amount of the prices specified in the Contract for the Work awarded to the Contractor; and

(c) an executed labour and materials payment bond in the amount of fifty percent (50%) of the total amount of the prices specified in the Contract for the Work awarded to the Contractor.

Waiver of Bonding: The Corporation reserves the right prior to the expiry of fourteen (14) days after award of the Contract to waive the requirement for any or all bonding. The Contractor acknowledges that the prices specified in the Optional Pricing lines in Section 6.3 of the Forms of Proposal identify the cost of any bonding required by this section and that, if the Corporation exercises its right in this section to waive bonding, the Corporation shall be entitled to a reduction of the prices specified in the Pricing and/or Rate Sheets in the Forms of Proposal equal to the amount the Contractor included in such prices for the bonding.

5.15 LEGAL COUNSEL

Proponents should not retain Davis LLP to advise or assist them in any matter relating to this RFP. By submitting a Proposal, the Proponent expressly consents to Davis LLP continuing to represent the Corporation for all matters in relation to this RFP and the subsequent Contract, including any such matter that is adverse to the Proponent, despite any information of the Proponent and any solicitor-client relationship that the Proponent may have had, or may have, with Davis LLP in relation to

matters other than this RFP. This section is not intended to waive any of the Proponent's rights of confidentiality or solicitor-client privilege. The Corporation reserves the right at any time to waive any provision of this section.

SECTION 6 FORMS OF PROPOSAL

Note: *To obtain a copy of this Section 6, Forms of Proposal in Microsoft Word format, please send an e-mail to the Corporation's Designate clearly stating your request.*

These Forms of Proposal are provided as an outline as to what the Corporation requires from the Proponent to perform complete and comprehensive evaluations. Proponents may attach additional and/or supporting pages, as required to provide complete information within their Proposal submission, at the Proponent's discretion.

Proposal Execution

Each corporate member of a Joint Venture should execute the Proposal Forms.

6.1 ADDENDA AND QUESTION AND ANSWER ACKNOWLEDGEMENT

Proponent acknowledges receipt of, and has taken into consideration, the following Addenda and Question and Answer series issued through the RFP process:

Addenda # _____ Received _____ Q&A # _____ Received _____

Addenda # _____ Received _____ Q&A # _____ Received _____

Addenda # _____ Received _____ Q&A # _____ Received _____

Addenda # _____ Received _____ Q&A # _____ Received _____

Addenda # _____ Received _____ Q&A # _____ Received _____

Addenda # _____ Received _____ Q&A # _____ Received _____

6.2 PROPOSAL FORM

To: YUKON ENERGY CORPORATION
Box 5920, 2 Miles Canyon Rd
Whitehorse YT Y1A6S7

Attention: Matthew Sills
Corporation's Designate

Reference: **RFP #2013-032**

RFP Title: Whitehorse Diesel-Natural Gas Conversion Project, At Whitehorse, Yukon, Engineering Procurement And Construction Contract

Proposal Submitted by:

Proponent's Legal Business Name: (Please Print)

_____

Proponent's Business Address:

_____

Phone: _____ **Fax:** _____ **Email:** _____

hereby declares that it is *(strike out whichever does not apply)*

(a) a company duly incorporated under the laws of

_____
(Jurisdiction and date of incorporation)

(b) a sole owner, partnership or joint venture carrying on a business under the name stated above, with the names, addresses and places of incorporation, if any, of all partners or members of the firm being the following: If a joint venture, indicate the lead Proponent and percentage participation of each member.

_____
_____
_____

By submitting a Proposal, the Proponent warrants:

1. Proponent has carefully examined the RFP Documents together with all other factors affecting the Work and proposes to furnish the Work as outlined in the RFP.
2. At the time of submitting this Proposal, there is no actual, apparent, or potential conflict of interest with the Corporation, except as disclosed in these Proposal Forms.
3. In the event of Proponent's Proposal being accepted, Proponent agrees to enter into a Contract with the Corporation for the amounts specified in the Pricing Sheet in Section 6.3, or as otherwise agreed between the parties in a subsequent Contract.
4. Proponent acknowledges that the Corporation is subject to the Personal Information Protection and Electronic Documents Act ("PIPEDA"), and the Access to Information and Protection of Privacy Act and declares the following information and records submitted in its Proposal to constitute trade secrets or information, the disclosure of which could reasonably be expected to harm significantly its, or a third party's, competitive or negotiating position or result in any undue financial loss or gain:

   _____

   _____

   _____

   _____

IN WITNESS WHEREOF, Proponent has executed at _____this ___ day of _____, 20___.

Authorized Signatory(s)

(print name)	(signature)
(print name)	(signature)

PROPONENT'S INFORMATION

REQUEST FOR PROPOSALS (RFP) #2013-032
WHITEHORSE DIESEL-NATURAL GAS CONVERSION PROJECT
AT WHITEHORSE, YUKON
ENGINEERING PROCUREMENT AND CONSTRUCTION CONTRACT

Proponent's Corporate Name: _____

Date and Place of Incorporation: _____

Legal Structure if not Incorporated: _____

If a subsidiary, indicate subsidiary office address:

_____

_____

Contact Name for this Proposal: _____

Title of Contact: _____

Contact telephone no.: _____

Contact e-mail address: _____

Provide details on union certifications and employer bargaining affiliations, if any, applicable to the Work, including those for each subcontractor:

_____

_____

Collective Agreement expiry, as applicable to the Work:

_____

6.3 CONTRACT PRICE

REQUEST FOR PROPOSAL (RFP) #2013-032
WHITEHORSE DIESEL-NATURAL GAS CONVERSION PROJECT
AT WHITEHORSE, YUKON
ENGINEERING PROCUREMENT AND CONSTRUCTION CONTRACT

Based on the RFP requirements and supporting information submitted as part of the Forms of Proposal, the Proponent shall provide a firm price, stated in Canadian Dollars.

Proponent shall provide a breakdown of the Contract Price in the form below. The rates and prices entered by the Proponent against each item of work shall accurately reflect the cost of the resources required to complete it. No item of work shall be left blank or described as "included".

Item	Canadian $
Home Office Engineering	
3 166.5 m^3 (net) LNG tanks delivered	
Total equipment (excluding tanks)	
Total materials	
Mobilization to Project Site	
Structural/Architectural Construction	
Mechanical/Piping Construction	
Electrical/Instrumentation Construction	
Painting and Insulation	
Construction Indirects	
Training	
Pre-commissioning, commissioning, start-up, testing and Vendor representation at Project Site	
Demobilization from Project site	
PRICE BEFORE GST	
GST	
TOTAL CONTRACT PRICE INCLUDING GST	
Optional Pricing:	
50% labour and materials bond (Exclusive of GST)	
50% performance bond (Exclusive of GST)	

Please Note: the Corporation desires to have the lowest life cyclem cost of ownership. Therefore, for the LNG tanks, please provide the following information:

- the vendor,
- the contract price for the three 166.5 m3 LNG tanks and
- the boil off rate for each vendor's tank.

The Proponent shall supply a payment schedule in as per the form shown in Schedule H to the Contract. Each month must contain at least 3 events that can be verified complete during that month and contribute the majority of the value of the monthly payment.

The Contract Price shall include all costs paid by Contractor including by not limited to freight, insurance, and government assessments of any kind, and level of government and any country. The Contract Price shall not include the insurance described in the Contract as being provided by Owner, which is defined in Part 15 of the Contract.

6.4 EXPERIENCE IN SIMILAR WORK

REQUEST FOR PROPOSAL (RFP) #2013-032
WHITEHORSE DIESEL-NATURAL GAS CONVERSION PROJECT
AT WHITEHORSE, YUKON
ENGINEERING PROCUREMENT AND CONSTRUCTION CONTRACT

Proponent is to provide a list of at least three (3) references for projects in similar scope and size to the Work contemplated in this RFP including when the work was completed, a description of the work, the client for whom the work was performed and a budgeted value for the work.

Proponent's Full Business Name:

_____

External References:

Year Completed	Work Description	Customer/Client	Work Value

YEC (internal) References

Year Completed	Work Description	Contact Name	Work Value

The Proponent is to advise if any projects were delayed or ran over budget, the reasoning for the overrun(s), and the mitigation strategy that was employed to bring the project back on track. Additional information should be attached, referencing this Proposal Form.

The Corporation reserves the right to contact the Proponent's references at the Corporation's absolute discretion, whether the Proponent's reference(s) were provided in this Proposal Form or not.

6.5 CONFLICT OF INTEREST; FULL DISCLOSURE

REQUEST FOR PROPOSAL (RFP) #2013-032
WHITEHORSE DIESEL-NATURAL GAS CONVERSION PROJECT
AT WHITEHORSE, YUKON
ENGINEERING PROCUREMENT AND CONSTRUCTION CONTRACT

Proponents are to provide a written statement of full disclosure addressing the following:

- Any personal relationship to any employee of the Corporation who makes recommendations concerning the award of the Proposal contemplated within this RFP or any employee (or immediate relative of an employee) of the Corporation with any direct or indirect pecuniary interest, ownership or directorship with respect to the Proponent;
- Any business relationship with the Corporation, any of its staff, employees, officers, directors or board members;
- Any matter involving a dispute with a claimed value in excess of $50,000 which is the subject of any current, pending or threatened mediation, arbitration or litigation proceeding; and
- Any proceedings involving the Proponent under the *Bankruptcy and Insolvency Act* (Canada), the *Companies Creditor Arrangement Act* (Canada) or similar legislation.

The Proponents should specifically address the requirements of this section by either providing appropriate disclosure or by indicating that they have nothing to disclose in respect of the matters listed above.

The Proponents must advise the Corporation of any change in the foregoing throughout the RFP process or intended negotiation period.

The Corporation reserves the absolute right to eliminate any Proposal or terminate any resulting Contract(s) without prejudice for failure to disclose the information required in this section and/or for disclosure at any time of proceedings in the nature of bankruptcy or insolvency by or against the Proponent.

Proponent's Full Business Name:

_____

Proponent's Statement:

_____

_____

_____

_____

_____

_____

_____

APPENDICES

APPENDIX A Letter of Intent to respond

APPENDIX B Specifications

APPENDIX C EPC Contract

APPENDIX D Basis of Design

APPENDIX E Process Flow Diagrams and Piping and Instrumentation Diagrams

APPENDIX F Data Sheets

APPENDIX G Site Layout

APPENDIX H Sample Fuel Specification

APPENDIX I 2010 National Building Code Seismic Hazard Calculation

APPENDIX J City Of Whitehorse Thermistor Data

APPENDIX K YEC Health And Safety Policy And Environmental Policy

APPENDIX L YEC Jobsite Spill Response Plan

APPENDIX M Yukon Oil And Gas Act

APPENDIX N Yukon Oil And Gas Regulations

APPENDICES

The following Appendices are included to this RFP and form part of the RFP. The Appendices provide additional details as to the requirements and details of the Work, and should be reviewed in detail by the Proponent prior to submitting a Proposal.

APPENDIX A – LETTER OF INTENT TO RESPOND

LETTER OF INTENT TO RESPOND

TO YUKON ENERGY CORPORATION'S
REQUEST FOR PROPOSALS #2013-032

EPC LNG STORAGE FACILITY
WHITEHORSE DIESEL-NATURAL GAS CONVERSION PROJECT

RFP #2013-032

Email to: **Matthew Sills**

Yukon Energy Corporation
matthew.sills@yec.yk.ca

THIS IS TO CERTIFY THAT:

_____ intends to respond to the above-noted Request for Proposals.
(Name of company / individual)

Our contact is:

Name: _____

Mailing Address: _____

_____

_____

Email Address: _____

Telephone Number: _____

Facsimile Number: _____

Signed by: _____

(Print name): _____

Title: _____

Note: Only those Proponents who indicate their intent to respond will receive subsequent information.

APPENDIX B – SPECIFICATIONS

MAJOR PROCESS SYSTEMS

Preface

The following is a description of the LNG Facility and how it is intended to be designed, constructed and operated. All equipment associated with the LNG Facility mentioned will be provided by Contractor unless specifically excluded.

YEC will hire a Project Manager to manage Contractor and the project interfaces between Contractor and the other contractors hired to complete the total project. As explained in Schedule E, the total project includes the LNG Facility and a power plant to consume the LNG that will be constructed simultaneously. Also, a single civil contractor will be hired to construct all undergrounds, all roads, foundations and security fencing for the total project, which includes the LNG Facility. The interface points of the LNG Facility are detailed in Schedule E of the Agreement.

In addition to the interfaces detailed in Schedule E, Contractor should also coordinate the following with the YEC project manager:

1. Voltage and amperage of supply of electricity to the project. At the interface point, 600V electricity will be provided. If 120V or 240V electricity is required, the best way to supply this power should be coordinated with the YEC project manager.
2. The location of the firewater loop within the LNG Area. Firewater is not used to fight LNG fires, however, the firewater loop is being extended to the LNG Area to provide firewater in the event that the vegetation outside the LNG Area catches fire.
3. The Flare location is currently undefined. Contractor shall pick a location as the basis of their contract price and then coordinate a final location with the YEC project manager.
4. There is no nitrogen storage or generation on site. Liquid nitrogen is not conveniently available, so nitrogen will be provided in cylinders.
5. Contractor shall provide an N+1 instrument air compressor and dryer skid to meet the needs of the LNG Area. The instrument air compressor skid can be installed in the shelter that houses C-802, the BOG Compressor.

All references to gallons shall be understood to be US gallons. 1 US gallon = 3.785 liters.

The design and construction of the LNG Facility shall be in compliance with (1) the Yukon, Canada, Order-in-Council 2013/162, Oil and Gas Act, (2) the Canadian Standards Association Standard, Z276-11 Liquefied natural gas (LNG) – Production, storage, and handling, and (3) all codes and standards referenced within the previous documents (1) and (2).

1.0 Introduction

Natural gas from LNG is proposed as a major source of energy supply for the Yukon Energy Corporation in Whitehorse, Yukon Territories. The goal is to design and construct an LNG facility that is a simple to operate, safe, code compliant, reliable, and energy efficient storage and sendout facility. LNG will be transported by a fleet of dedicated LNG highway tankers (provided by others) as a cryogenic liquid from an LNG export terminal in Alberta, offloaded into the LNG storage tank at Whitehorse, and vaporized as needed to maintain a stable supply of natural gas for power generation. An LNG dispenser will be provided to fuel LNG trucks. The design basis is to design and construct LNG facility to include:

- LNG truck unloading facilities.
- Three horizontal LNG vacuum jacketed bullet tanks with 166.5 m3 (usable) 188 m3 (gross) of capacity and two future horizontal LNG vacuum jacketed bullet tanks with 120 m3 (usable) capacity. The three 166.5 m3 tanks will be in the northern LNG storage containment area and the two future 120 m3 tanks will be in the southern containment area.
- Impoundment of LNG spills in compliance with CSA Z276.
- LNG regasification by vertical shell & tube vaporizers using waste heat recovery from power generation and water/glycol transfer fluid to heat LNG to natural gas to between 10C and 40C. The vaporizer and black start heater will be within the LNG area and the water/glycol–waste heat heat exchanger, expansion tank, and circulating pumps will be outside the scope of the LNG contractor.
    - Contractor will specify, to the YEC project manager, the flowrate of the 50% ethylene glycol-water required at the LNG area interface point (Schedule E) assuming that the 50% ethylene glycol-water arrives at 80C .
- Send-out Gas Measurement using an ultrasonic meter will allow YEC to monitor the mass of natural gas and compare to power generated on a real time basis.
- Gas Distribution – Natural Gas Piping System (Contractor will install to an interface point, see Schedule E, and the YEC project manager will manage the balance of the natural gas pipeline.)
- Contractor will install all control system hardware in the new 21m by 24m substation located about 100 yards north of the LNG storage tanks. The system must be capable of communication with the YEC SCADA (“SCADA”) system or must provide Remote Transmitting Units, as required, to allow the PLCs to communicate in SCADA language with the hardware housed within the existing control room. Contractor will provide a termination strip within the substation so that the YEC project manager can extend optic fiber to the SCADA hardware. Contractor will also provide the logic necessary for the YEC project manager to program the SCADA so that the necessary HMI screens can be generated.
    - Safety Instrumented System (SIS) Programmable Logic Control System (PLC) will be installed into the substation. Data from the SIS will be viewed through the SCADA HMI in the existing control room.
    - Fire & Gas (F&G) Detection and Alert System PLC will be installed in the new substation. The F&G Detection and Alert System for the LNG area will be displayed and controlled through the existing SCADA in the existing power plant control room.

- The LNG Facility will be unmanned, but it will be monitored 24/7.
- The initial piping shall be designed for the full power plant buildout case of 28.6 MW power generation at 40% efficiency plus 10% design allowance.
- An 800 feet of 8 foot high vapour fence shall be installed by the LNG contractor as per the layout drawing.
- The LNG facility is fenced with a 7 ft high chain linked security fence topped with 1 foot of razor wire except for the north border that is the common border with the Power Plant. A motorized entrance gate will be provided in the east fence and will have a speaker box to communicate with the control room and remote activation from the control room. A motorized locally activated exit gate will be provided in the south fence. (The security fence and associated gates are not included in the LNG Contractor's scope of work and will be installed by others.)
- See individual specification sheets for a description of tagged equipment.

2.0 LNG Highway Tanker Unloading

2.1 LNG Highway Tanker Unloading Bays

One LNG highway tanker bay is provided. The unloading bay includes:

- Manifold for unloading single LNG tanker at a time
- Local man-machine interface for "load recognition and verification"
- Unloading flow custody transfer meter (Corellas meter) to measure LNG tanker inventory transfer
- Cryogenic liquid (3" vacuum jacketed) and vapor (2") hoses to connect the LNG highway tanker to LNG unloading headers
- LNG unloading header and isolation valves
- Vapor return header and isolation valves
- The design unloading rate is 68 m3/h.
- Two 100% tanker LNG unloading pumps.
- The unloading bay area is provided with a spill collection system to transport potential LNG spills to an impoundment that can receive a 10 min spill at the maximum tanker unloading rate.

The unloading bay's two (2) 100% LNG pumps operate as an N+1 system. Cold retention in unloading facility piping and pumps is provided by thermal insulation of piping and pumps. Piping shall be designed so that it can be cold shocked with LNG if warm. Extended non-use of unloading facilities will result in warm-up of piping and pumps when LNG evaporates to the vapor system. Unloading system must be designed so that it can thermal cycle between ambient and LNG temperatures frequently.

The capability for LNG tanker loading is also provided so that the LNG storage tanks can be de-inventoried, if necessary. The LNG tank pumps will pump the LNG through a normally car seal closed pipe to the same liquid and vapour hose connections.

In the future, LNG trucks will fuel with LNG using the dispenser at the unloading area and the LNG pressure from the tanker unloading pumps. Capability is also provided for delivering LNG from the LNG storage tank pumps. The LNG dispenser shall be curbed with a trench that leads to the impounding basin.

2.2 LNG Highway Tanker Unloading Operations

LNG highway tanker unloading is accomplished by performing a sequence of operational steps.

- The LNG truck/tanker arrives at the YEC plant, announces itself at the gate speaker box at the east gate and the control room activates the motorized gate to open.
- The truck unloading operation is performed by trained facility operators who will remain in attendance throughout the unloading procedure. Truck drivers are trained and authorized to operate valves and move hoses for unloading operations and are expected to monitor the unloading operation.
- The driver secures the truck at the unloading bay, turns the truck engine off and chalks the wheels. Truck ignition keys are removed and secured during unloading.
- Driver identity, truck/tanker identity and quantity to be unloaded are validated as accurate in the local HMI that is linked to the SCADA system.
- A weather shelter with electric heater is provided near the unloading area. The local HMI is housed inside this shelter.
- An umbilical cord is connected to LNG highway tanker to monitor truck/tanker safety systems described in Section 2.3.
- LNG unloading and vapor hoses are connected between the tanker and the unloading manifold.
- The hand switch on the HMI activates the on-off valves in the LNG unloading line and the natural gas vapor line.
- Vapor pressure in the tanker is controlled by FCV 102 a pressure control valve that can be regulated by the SCADA system in the control room (“SCADA”) or at the local HMI by dialing in a pressure set point. The HMI will be equipped with a selector switch to choose which devise controls the set point.
    - One optimization is to provide sufficient pressure on the vapor space of the tanker to maximize the unloading rate.
    - A second optimization is to have the lowest positive pressure possible at the end of unloading to minimize the number of natural gas molecules returning with the empty truck.
    - Under no condition should the tanker be permitted to experience vacuum while unloading. If PT 120 senses a low pressure, 0.2 barg for example, it will stop the unloading pump and close the on-off value in the LNG unloading line.
- The manual LNG unloading valves are opened allowing LNG to flow from the tanker providing cool down of the LNG unloading hose, piping and the LNG unloading pump.

- The LNG tanker unloading pump is started at a slow flowrate. The flow is controlled by FCV 117A. The HMI operator will have the ability to manually control FCV 117A until the operator determine that the pump has prime and it operating normally at which point he will switch the pump to automatic. Normally the transfer rate will process at maximum rate, although FCV 117A may need to limit the flowrate as the tanker becomes empty to avoid the pump losing prime.
- LNG unloading continues until the tanker is empty of liquid. The LNG pump automatically stops when the Corellas meter senses a low (no) flow reading and prevents the pump from running dry.
    - A light and sound alarm will alert the operator when the pump shuts off.
- The operator confirms that the LNG tanker is completely empty of liquid.
- Vapor and LNG on-off valves on the unloading manifold are closed by the low flow signal.
- Hoses are depressurized, and purged and disconnected, and umbilical cord disconnected.
- After offloaded LNG quantity validation is completed in the facility measurement system, the driver either departs with the LNG tanker empty of liquid or moves the B-train forward to unload the back tanker.

Note: Contractor to provide necessary accessories such as HMI, vacuum jacketed 3" unloading hose with weight counter balance, 2" unloading hose, tanker umbilical cord with proper receptor in coordination with YEC project manager / LNG tanker provider and associated plant hardware to process tanker umbilical information.

2.3 LNG Highway Tanker Unloading Safety Features

The LNG highway tanker unloading facility incorporates a number of safety features to prevent unsafe conditions:

- F&G detectors are installed in the LNG highway tanker unloading area in specific locations where possibility of LNG spills, gas leaks, flame, excess heat and low temperature indicate unsafe conditions. Emergency manual call points are provided, as well as sirens and beacons to alert personnel of emergency situations. Logic in F&G detection control systems will automatically trigger an emergency shutdown for specific events.
- A terminal-to-truck umbilical cable is connected to the LNG highway tanker that ensures that truck engine is off, LNG highway tanker is earthed, and truck & tanker braking systems are set and wheels chocked before loading is permitted. Unloading and vapor return hoses are vulnerable to "drive-off" with hoses connected as hoses are not provided with breakaway couplings to provide a "weak point".
- ESD valves are provided in the liquid and vapor lines to isolate the system in an emergency. An "ESD-1" isolates and stops LNG tanker unloading and stops pumps. Automatic ESD-1 activations are provided for fire and flammable gas release scenarios. Manual ESD-1 activation hand-switches are provided at 2 locations in the tanker unloading area.
- Barriers protect pipe work from truck impact as practical.
- Fire suppression with chemical fire extinguishers are provided in the event of fire.

3.0 LNG Storage

LNG storage on site provides a working inventory of LNG to provide continuous natural gas send-out for power generation. The three 166.5 m3 tanks will be in the northern LNG storage containment area and the two future 120 m3 tanks will be in the southern containment area. Both containment areas will drain to the impoundment basin.

3.1 Single Containment Tank

The LNG storage tank system at YEC consists of three 166.5 and two 120 cubic meter net (m^3) horizontal vacuum jacketed bullet tanks. The layout is designed to be able to conveniently add the two additional 120 cubic meter tanks in the future. (The foundations for the two future tanks will be constructed during the initial construction as well as flanged connections to the inlet, suction and vent lines as well as spare terminated control optic fibers connected to the PLCs in the substation.) These tanks have a stainless steel inner tank that contains the LNG and a carbon steel outer tank. The volume between these two tanks is under vacuum. The vacuum serves to thermally insulate the inner tank from the ambient conditions. Each tank sits on a two pedestal foundation. (Foundations will be constructed by another contractor for the two future tanks as well as for the three tanks to be installed with the initial installation.) The tanks are single containment tanks because only the stainless steel inner tank is capable of containing LNG

The vacuum insulation provides thermal insulation with typical boil off rate equal to 0.25%/day (max) of the capacity of LNG in the tank. The withdrawal line is located for bottom withdrawal. The LNG tanks have piping and remotely actuated open/closed isolation valves designed to allow tank filling and withdrawal to / from each tank. LNG tanks fill and withdrawal lines are normally open unless there is an operational reason or abnormal condition where the valves are closed. The LNG storage tanks withdrawal and fill nozzles are installed to allow for liquid level equalization by gravity via the bottom withdrawal tank piping. The vapor spaces are all tanks are connected.

The LNG tanks will have top spray filling. Each tank is instrumented with two independent level gauges that provide inventory readings and also can close the inlet and outlet valves in the event of unusual events, e.g., high level or rapidly decreasing level.

3.2 LNG Tank Pumps

The LNG tanks feed LNG to two external LNG tank pumps from bottom withdrawal lines from each LNG tank. The LNG tank pumps are single stage centrifugal pumps submerged in a pressurized LNG pump canister with an integral induction electric motor and variable frequency drive. LNG tank pumps increase LNG pressure to the natural gas distribution pressure of 5.3 to 8.0 barg required by the power plant engines. On rare occasions, these pumps will be used to unload the storage tanks to trailers or to feed LNG to the LNG fuel dispenser. The pumps are sized for 50% of the ultimate design flowrate of 12.2 m3/h of LNG. Two 50% LNG pumps will be installed initially and the foundation for the third plus convenient tie-in flanges, provision for electricity connection and spare optic fiber will be provided during the initial construction.

The LNG tank pump will start-up on recycle until the operator is convinced that the pump is cooled and operating normally at which point he will have the recycle valve closed and direct all

flow to the vaporizers. The flow to the vaporizers will be controlled by FCV 703A. The LNG pumps can also be controlled with the VFD to reduce the flow during recycle or if the flow to the power plant is very low.

3.3 LNG Secondary Containment

For code compliance, the LNG facility is required to have secondary containment to prevent potential offsite migration of LNG spills and releases for 2 scenarios:

1. Total LNG storage tank failure
2. A 10 minute LNG release from the process or transfer operations using credible events to determine the potential quantity of LNG spilled.

To comply with CSA Z276 standards to mitigate these scenarios, the single containment LNG tanks require an external LNG Spill Containment Systems to retain loss of LNG containment from storage. The LNG facility also includes secondary containment for equipment and piping in the unlikely event of a release of LNG primary containment systems that will contain the liquid and direct the spill to a containment area or in-ground impoundments where the LNG would be held until it evaporates to the atmosphere.

Spill containment systems include LNG impoundment areas, LNG sub-impoundments, paving, curbs, and LNG transfer trenches anywhere is LNG is stored, processed, or unloaded. Area paving beneath any equipment that contains LNG will be graded to direct any LNG spill toward a transfer trench. Curbing would prevent the LNG from flowing off the area paving by any route other than a transfer trench. Storm water landing in areas outside the limits of the LNG spill containment curbing will be directed to storm water facilities that are separate from the LNG spill containment facilities. Storm water that has flowed into the LNG impoundment pit will be removed using automatic water pumps installed in the impoundment pit. Pumps designed for automatic operation are provided with automatic shutdown controls to prevent operation when LNG is present or if water temperature is below its freezing point.

As already stated, the impoundment pit will be built by others managed by the YEC project manager. The pumps and piping inside the impoundment pit will be constructed by Contractor. A cover over the impoundment pit designed to keep snow from falling into the impoundment pit will also be provided by Contractor.

3.4 LNG Facility Siting

For code compliance, the LNG facility is required to demonstrate that potential LNG releases to secondary containment systems will not adversely impact adjacent property from thermal radiation or vapor releases. To satisfy these requirements approximately 800 feet of vapour retention fence will be constructed by the LNG Contractor.

3.5 LNG Storage Safety Features

The LNG storage facility incorporates a number of safety features to prevent unsafe conditions:

- F&G detectors are installed in the LNG storage tank areas in specific locations where possibility of LNG spills, gas leaks, flame, excess heat and low temperature indicate

unsafe conditions. Emergency manual call points are provided, as well as sirens and beacons to alert personnel of emergency situations. Logic in F&G detection control systems will automatically trigger an emergency shutdown for specific events.

- ESD valves are provided in the liquid and vapor lines of the storage tanks and LNG pump outlets and natural gas lines to isolate the system in an emergency. An "ESD-2" isolates and stops the entire LNG Facility. Automatic ESD-2 activations are provided for fire and flammable gas release scenarios. Manual ESD-2 activation hand-switches are provided at 2 locations in the tanker unloading area and in four locations in the storage and send-out area.

4.0 Vapor System

LNG vapor is contained within the process during normal operations by an integrated vapor system. Atmospheric venting is considered an abnormal condition and wasteful, and avoided except for emergency conditions to prevent over pressurization in piping systems, tanks and vessels. Vapor is generated as a result of ambient heat transfer into the system through thermal insulation systems or operating equipment, e.g. pumps, that directly generates heat in LNG process fluids. The function of the vapor system is to provide:

- A safe conduit for vapor distribution, vapor pressure balancing, and utilization within the LNG facility without atmospheric venting;
- When excess vapor is produced and the high pressure set-point is reached, the BOG compressor automatically starts and compresses and transfers excess vapor to the gas distribution system for beneficial use as natural gas fuel, and avoids atmospheric venting;
- When a vapor deficit occurs, vapor makeup "pad gas" is automatically provided from the natural gas send-out line to the vapor system to prevent low or vacuum pressure from occurring in the LNG storage tank vapor space and vapor system.
- In the unlikely event that vapor production exceeds vapor recovery capacity of the BOG compressor, the excess is flared to the atmosphere as an abnormal operating condition to prevent over pressurization in the LNG storage tank vapor space and vapor system.
- PSV's (pressure relief valves) and TSV's (thermal relief valves) are hard piped to the vapor system for collection except LNG tank pressure relief valves that discharge directly to the atmosphere.

4.1 LNG Tank Vapor

The vapor space of the LNG storage tanks are connected such that the vapor spaces of all tanks are equalized. This common vapor space piping is connected to a vapor header line that includes connections to the suction ports of the BOG compressor, pad gas supply, PSV's, TSV's, LNG pump canister vapor space, the LNG tanker vapor hose connection and the flare. During the LNG highway tanker unloading operations, LNG liquid entering the LNG tanks displaces vapor in the LNG storage tanks. This excess vapor flows from the LNG tanks and is available to maintain the pressure range within operating limits of the vapor space of the LNG tanker. PT 102 control the final pressure in the LNG tanker as explained above.

4.2 BOG Compressor

BOG compressors operate when there is high pressure in the vapor system and compressors are sequenced and automatically operate with sufficient capacity to maintain LNG tank vapor space pressure to prevent a high pressure condition that could lead to relief valve lifting and atmospheric venting. BOG compressors operate in pressure control from PT 808, and are designed to recover the excess vapor and transfer natural gas to the send-out line for use as fuel gas, and designed to maintain normal operating conditions as set in the control logic. The BOG compressor discharge port is piped to the natural gas send-out line upstream of the send-out meter.

The carbon steel BOG compressors are not designed to compress gas at cryogenic temperature and therefore gas vapor from the LNG tanks must be warmed prior to compression to protect the compressor from exposure to low temperature vapor. A heat exchanger is connected to the compressor suction port, and receives heating from the glycol/water loop to warm the vapor prior to compression. The glycol-water flow to the BOG heat exchanger, E-615 is controlled by FCV-611. When PT-808 is above set point and the BOG compressors are operating, TT-809 controls FCV-611 to maintain the BOG gas temperature above 10C. If TT-809 senses BOG below -15C, then it will shutoff the BOG compressor to protect is against cold temperature.

The BOG compressors and BOG heat exchanger will be in a curbed area under roof supplied by Contractor such that water leaked from compressor does not wash into storm water. The black start heater will also be in this shelter.

The 50% ethylene glycol-water loop could freeze if the ambient temperature drops below -30C for an extended period, so the flowpath must be insulated and electric heat taped to maintain the temperature of the flow path, which includes E-615 and the LNG vaporizer, above -25C.

4.3 Pad Gas

Pad gas is provided when there is low pressure in the vapor system. Pad gas operates in pressure control, and is supplied from the natural gas send-out line that will automatically maintain vapor space pressure to prevent a low or vacuum pressure condition. PRV- 805A and PRV-805B will operate to allow gas to flow into the vapor space header any time the vapor space pressure drops below 0.2 barg. PT-806 will alarm when the pressure reaches 0.2 barg.

4.4 LNG Highway Tanker Vapor Handling

As explained above, during LNG highway tanker unloading the vapor space pressure will decrease as the liquid is unloaded unless externally replenished as the increased rate of evaporation is generally not adequate to replace the vapor space volume. To prevent critical low pressure in the tanker, a vapor return line is provided to maintain minimum tanker vapor pressure. The vapor pressure is maintained sufficiently high to force an adequate flowrate of LNG to the unloading pump while minimizing the final vapor space pressure in the empty tanker. To return the tanker above a vapor pressure of 0.5 barg is wasteful as YEC does not get credit for molecules returned on the tanker.

4.5 LNG Relief Valve Discharge Containment

If the LNG facility is blocked in for an extended period of time without natural gas send-out, vapor pressure will build enough to lift pressure relief valves where excess gas is safely vented but only as a method of last resort. Each LNG tank is equipped with four pressure relief valves, two of which are always on stream and two of which are on the dead leg of a three way valve.

When the system is operated correctly, the BOG generation rate should not be sufficient to raise the vapor space pressure such that it lifts the PSVs. The reason is that YEC has several fuel users that can beneficially consume the BOG to maintain the vapor space pressure below the PSV set point of 100 psig, such that little, if any, venting is anticipated.

4.6 Flare

A single LNG facility flare system is provided to facilitate disposal of excess vapor pressure to the atmosphere in a safe location in the event of abnormal process conditions or pressure buildup that exceeds fuel gas consumption. Flaring is preferred over venting of un-ignited gas due to concerns of producing significant releases of flammable gas that could potentially create safety hazards from flammable mixtures in air, ground level accumulation of vapor, and undesirable noise.

The vapor disposal system is fundamentally an elevated vertical pipe with a flare tip and located in a safe area where the thermal radiation from burning vented natural gas vapors does not create a problem. In normal operations, there are no hydrocarbon emissions from the flare. The stainless steel pipework feeding the flare is provided with a small low point 'boot' to detect liquid carry-over into the vent system. In the event of liquid being present, a level element in the boot alarms. No liquid KO drum is provided as the only potential liquid release sources into the vapor system are TSV's. A low temperature shutdown shall be installed in the vent line to shutdown all systems until the low temperature is confirm to be vapor and not liquid.

The flare will not ignite until it senses flow downstream of the backpressure regulator. Upon sensing flow, a solenoid valve will allow nitrogen to flow from a nitrogen bottle to purge any air in the line. After a sufficient period, the flare will automatically be ignited without the possibility of igniting a flammable mixture within the vent pipe.

The flare is designed for a release rate of about 120 m3/h – this rate is to be confirmed by the LNG Contractor. The design vent height above grade is [TBD].

4.7 Thermal Relief Valve Discharge

For LNG service, design pressure of cryogenic piping is well above maximum operating pressure and overpressure protection is effectively provided elsewhere in the system to prevent over pressurization. The exception is for LNG piping components vulnerable to a "blocked-in" condition where closed isolation valves could trap LNG between valves resulting in components being exposed to overpressure conditions. To protect components from a potential block-in case, hydraulic expansion (thermal) relief valves (TSV's) are provided to protect all sections of piping where operating valves could close, and potentially cause a "blocked-in" condition. For sections where manual valves could be closed, and cause a "blocked-in" condition, the manual valves are "car-sealed" open to prevent unauthorized closure.

All TSV's are uninsulated and have an uninsulated inlet, so that:

1. TSV relief is mainly vapor.
2. The TSV's have an uninsulated discharge, so that flow can be observed due to the frosting it causes on the bare pipe.
3. TSV's are sized for normal buildup under blocked in condition and the fire case.

TSV's relieve into a common vent header that runs un-insulated to the vapor system.

4.8 Cryogenic Flammable Vapor Relief Valve Discharges

In general, cryogenic flammable vapor relief valve discharges are piped to the vapor system, so that the vapor space of the storage tanks can be utilized to absorb the relieved gas volume and prevent discharge to atmosphere. The exception to the above is the LNG storage tanks relief valves. In accordance with CSA Z276 the storage tanks relief valves discharge directly with the atmosphere. The tanks' relief valves are located on the tank tops and the discharges to the atmosphere and the vent tips are elevated to limit hazards to the tank structure to acceptable levels. Sensors are provided to alarm through the control system if a tank relief valve vents.

Vent discharges are arranged to discharge vertically upwards and provided with a loose fitting, lightweight weather cap to prevent an accumulation of water, ice, snow or other foreign matter in the stack.

Contractor shall require LNG tank vendors to verify that the LNG tank relief valves can protect the tank under the following fire scenarios:

1. The PSVs will protect the tanks for two hours while being subjected to a thermal radiation of 10,000 BTU/hr-ft2 from a fire in the impoundment pit?
2. The PSVs will protect the tanks for one hour in the event of a forest fire. The LNG storage tanks will be exposed on the west (left) side by a green belt of trees. If the trees caught on fire, the tanks on the west side will feel thermal radiation along their length. The intensity is expected to be approximately 6,400 BTU/hr-ft2.

4.9 Non-Cryogenic Flammable Vapor Relief Valve Discharge

In the vaporizer fire case, pressure vapor relief valves vent to atmosphere.

There is no vapor relief on the gas distribution line other than fire case pressure reliefs because the pumping system cannot overpressurize the ANSI 150 system design pressure of 275 psig.

5.0 Piping Design

The facility piping systems are designed for off-loading rates of up to 68 m^3/hr (300 gpm) and peak send-out through the gas vaporizers to the gas distribution system of 12.2 m^3/hour LNG (265,000 SCF/hour gas flow equivalent). All LNG piping systems will be designed, rated, inspected, NDT (100% radiographic or ultrasonic inspection and pressure tested) and pressure

tested for maximum allowable operating pressure in accordance with ASME B31.3, Process Piping, and due consideration will also be given to the additional provisions of CSA Z276 with respect to piping systems and components for flammable liquids and gases with service temperatures below -29 ^{0}C (-20 ^{0}F). Piping systems will be designed and rated for maximum allowable operating pressure of 275 psig (ANSI 150 fittings). Contractor must confirm that no operating case can present a pressure in excess of 275 psig.

All piping systems are required to be pneumatically pressure tested to 1.5 X the design pressure (412.5 psig for 275 psig system) in accordance with ASME B31.3. Hydrotesting of LNG piping is to be avoided due to the difficulty of dewatering after the hydrotest. The LNG storage tanks will be hydrostatically tested at the manufacturing site in accordance with ASME Section VIII, Division 1. Welding is the preferred method of joining pipe such that flange connections and other potential leak joints are avoided wherever practical. Piping should be designed for the applicable seismic criteria, and the resultant stresses will be within those allowed in ASME B31.3, Process Piping. The piping systems and their design will take into account fatigue, expansion, contraction and thermal cycling when designing the supports and laying out the piping systems. Elbows and pipe anchors will be required at strategic locations to prevent excess stresses – expansion joints should be avoided unless no other practical solution is available. The insulating system to be installed will not propagate fire and will maintain its properties during a firefighting event. ASTM A312 and ASTM A358 type 304/304L (dual certified) stainless steel pipe will be used for cryogenic or hazardous fluid services. Valves will comply with the requirements of CSA Z276.

The following piping shall be insulated as described:

- All LNG piping shall be insulated and should maintain LNG temperatures for a minimum of five days of no flow.
- The BOG vapor lines shall not be insulated except within 15 meters of the LNG storage tanks in all directions.
- The water-glycol system shall be insulated and heat traced to prevent the water-glycol solution from solidifying.
- The stormwater sump pumps and discharge lines shall be insulated and heat traced to prevent the water from freezing.
- The natural gas line to the power plant shall be insulated above ground.
- All carbon steel piping shall be designed to withstand ambient temperatures to as low as -55C.

The connection requirements of CSA Z276 for pipework will be incorporated into the piping design and into the specifications that govern welding, fabrication and erection of the piping system. Extended bonnets will be provided for valves exposed to cryogenic temperatures. All penetrations to or from LNG tanks will be provided with shutoff valves at the tank. Pipe welding procedures and welders will be qualified in accordance with ASME B31.3, Section IX of the ASME Boiler and Pressure Vessel Code. Pipe marking requirements will be included in the fabrication and construction process.

The design of the pipe supports will ensure that excessive heat transfer causing icing or embrittlement of the supporting steel will not occur. Piping will not rest directly on structural

supports, but separated with a pad to prevent friction, corrosion, and electrical conduction. Pipe supports constructed with thermally isolating structural materials will be used to transmit loads from the process pipe to the pipe supports without heat transfer. The piping systems will be suitably labeled with line identification and flow arrows. Valves will be installed at the extremities of each transfer system. Hydraulic shock analysis will be performed on all lines which contain an automatic shutoff valve, to ensure that line or equipment failure cannot be caused by hydraulic shock from rapid closure.

Pipe service	Fluid	Diameter Material	Insulated	Heat traced	Notes
LNG tanker unloading	LNG	3" 304L SS	Y	N	Insulation shall maintain LNG temp for 5 days after no flow with pipeline full of LNG and valve open to storage tank
LNG vapor rtn to tanker unloading	vapor	2" 304L SS	Y	N	
LNG storage withdrawal	LNG	2" 304L SS	Y	N	Bottom withdrawal piping from LNG storage tank to be 2". Insulation shall maintain LNG temp for 5 days after no flow with pipeline full of LNG and valve open to storage tank.
LNG vapor line from storage	vapor	2" 304L SS	Y	N	Vapor line to be uninsulated outside of 15 meters from LNG storage tank.
LNG storage to E-615	vapor	TBD" 304L SS	N	N	Vapor line to be uninsulated outside of 15 meters from LNG storage tank
E-615 to C-802	vapor	TBD" CS	Y	TBD	Carbon steel line to be designed to withstand ambient temperatures to as low as -55C.
C-802 to natural gas pipeline	vapor	TBD" CS	Y	TBD	Carbon steel line to be designed to withstand ambient temperatures to as low as -55C.
Flare line	vapor	TBD" 304L SS	N	N	
LNG from P-301 to VP-701	LNG	2" 304L SS	Y	N	Insulation shall maintain LNG temp for 5 days after no flow with pipeline full of LNG and valve open to storage tank.
Outlet of VP-701	vapor	4" 304L SS	Y	N	To CS spec break
Natural gas pipeline to interface point	vapor	4" CS	Y	TBD	Carbon steel line to be designed to withstand ambient temperatures to as low as -55C.
Water-glycol to / from VP-701	liquid	4" CS	Y	Y	
Water-glycol to / from E-615	liquid	TBD" CS	Y	Y	
Pad gas	vapor	2" CS / 304L SS	N	N	Carbon steel line to be designed to withstand ambient temperatures to as low as -55C.

6.0 LNG Vaporization

6.1 LNG Vaporizers

The facility operates using 2 -100% capacity stainless steel vertical shell & tube vaporizers that are connected to the glycol/water loop to provide the heat needed to vaporize LNG to natural gas. Vaporizers operate in pressure control mode to maintain downstream pressure at the generator engines of between 5.3 and 8.0 barg. FCV-703A will control the amount of LNG flowing to the vaporizer to match the pressure set point of at PT-709A. The gas send-out line also has temperature override, TT-708A, if outlet gas temperature falls below the gas discharge set point of -29^0C, ESDV-702A closes. Cold gas or LNG passing from the vaporizer is the critical design parameter to be avoided to prevent downstream carbon steel pipe from exposure to low temperature below the safe operating temperature of carbon steel.

The vaporizers are arranged in parallel with inlet and outlet manifold headers. Only one vaporizer will be onstream at a time; the other vaporizer will have its inlet valve closed. There are two overrides on the flow control loop; these are high pressure and low temperature at the vaporizer outlet where the occurrence of high pressure, PT-709A in excess of 8.5 barg, alarms and decreases LNG flow to the vaporizer. The vaporizer can be turned down the full range of 0 to 100 % of design rating. The common discharge of the vaporizers has an emergency shutdown valve to isolate the vaporizer in case of emergency. The closure of this valve on ESD is delayed to prevent LNG being trapped and on subsequent expansion lifting the vaporizer TSV valves.

The vaporizers shall be insulated and heat traced. The heat tracing shall turn on if the equipment temperature falls below -25C.

6.3 Glycol/Water System

Ethylene glycol-water solutions are commonly used in heat-transfer applications where the temperature in the heat transfer fluid can be below *32^oF (0^oC)*. Ethylene glycol is combined in a 50% mixture with water and used to avoid freezing and damage from expansion or corrosion (freezing point is approximately -35C). The glycol/water system is a closed loop process circulating between the power plant and the LNG Area.

When operating LNG shell & tube vaporizers, hot glycol/water is continuously circulated to provide the heat required for the phase transition of -260F (-161C) LNG to warm natural gas to between 10C and 40C. The glycol/water FCV of the onstream vaporizer, FCV-610A or FCV-610B, will be controlled by TT-708A to allocate the flow of glycol/water between the vaporizer and E-615. When the BOG compressors are not on and E-615 is not calling for heat, all of the glycol/water flow can flow to the onstream vaporizer to control the natural gas temperature near the top of the 10C to 40C range. When E-615 is calling for heat, then more of the flow is directed to E-615 to balance the heating duty.

All above ground lines and equipment containing the 50% ethylene glycol-water solution shall be insulated and heat traced. The heat tracing shall turn on if the equipment temperature falls below -25C. The pipe in the utilidor will be painted, wrapped and cathodically protected since the utilidor can have standing water.

6.4 LNG Vaporizer Operations-Black Start Heater

Since the LNG Vaporizers depend on waste heat from the power plant for the thermal energy to vaporize the LNG, and since the power plant intends to routinely start-up using natural gas, then a method must be provided to vaporize LNG to feed the power plant until the power plant can generate sufficient waste heat to sustain vaporization. The Black Start Heater will be used to warm the glycol/water ahead of the vaporizer to vaporize sufficient LNG to fuel 2.2 MW of power generation (at 40% efficiency); the power plant will require approximately 520 m^3/h of natural gas to generate 2.2 MW. During the use of the Black Start Heater, the flowrate of ethylene glycol-water will have to be reduced to allow the black start heater to warm the glycol/water to approximately 80C upstream of the vaporizer. This will be accomplished by using FCV-610A/B to control the flow of glycol/water through the vaporizer and thereby limiting the flow of glycol/water through the black start heater, E-604. E-604 will heat the glycol water solution to ~80C as measured by TT-609A/B. Within the vaporizer sufficient heat will be transferred to the LNG to allow TT-708A to register an acceptable temperature in the range of 10C.

LNG vaporization to send-out natural gas is accomplished by performing a sequence of operational steps in Black Start Heater Operational Mode.

- The LNG vaporizers are protected from being started prematurely by a number of process control interlocks that prevent the introduction of LNG to the vaporizers until all other systems are ready and stable. These same process interlocks will stop vaporization if any of the key components trip off during operations.
- Prior to startup of the vaporizers in Black Start Heater Operational Mode, the following equipment is started in sequential order:
    - Glycol/water loop circulating through vaporizer
        - Start glycol/water pumps
        - Maintain liquid level in glycol/water surge tank (to avoid cavitating circulating pumps)
        - Start the Black Start Heater.
        - FCV-610A/B will control the flow of glycol/water through the vaporizer to give a vaporizer inlet temperature of ~80C.
        - Maintain flow until the vaporizer itself has been heated to allow a minimum temperature of 65C on glycol/water return line from vaporizer.
            - Note that the temperature of the glycol/water return line from vaporizer will drop below 65C in Black Start Heater Mode after the introduction of LNG
    - LNG tank(s) withdrawal line open
    - LNG tank pump
        - Pump cool down sequence
        - Pump start in recycle
    - LNG vaporizer inlet control valve
        - Open valve 5%
        - Do not allow LNG flow to exceed 0.85 m^3/hr in Black Start Heater Mode

After reaching send-out pressure set-point, place valve in Black Start Heater Mode pressure control.

The Black Start Heater will also be used to provide heated glycol/water to the BOG heater, E-615, when needed to warm the BOG vapors prior to compression if the glycol/water loop is otherwise cold.

6.5 LNG Vaporizer Operations-Normal Operations

LNG vaporization to send-out natural gas is accomplished by performing a sequence of operational steps in Normal Operational Mode.

- The LNG vaporizers are protected from being started prematurely by a number of process control interlocks that prevent the introduction of LNG to the vaporizers until all other systems are ready and stable. These same process interlocks will stop vaporization if any of the key components trip off during operations.
- Prior to startup of the vaporizers, the following equipment is started in sequential order:
    - Glycol/water loop circulating through vaporizer
        - Start glycol/water pumps
        - Maintain liquid level in glycol/water surge tank (to avoid cavitating circulating pumps)
        - Minimum temperature of 65C on glycol/water return line from vaporizer.
    - LNG tank(s) withdrawal line open
    - LNG tank pump
        - Pump cool down sequence
        - Pump start in recycle
    - LNG vaporizer inlet control valve
        - Open valve 5%
        - After reaching send-out pressure set-point, place valve in pressure control

7.0 Sendout Metering

The meter station will have one (no installed spare) ultrasonic meter with space and tie-ins for one future meter run. The meter has a (minimum) design pressure of 275 psig and design temperature range –20°F to 104°F.

Meter stream is provided with double block and bleed isolation using ultrasonic flowmeter with temperature and pressure correction to provide mass flow measurement.

A bypass shall be provided across the meter.

8.0 Gas Distribution

From the vaporizers, natural gas is piped to the metering station and then to the gas distribution system comprised of thermally insulated above ground and carbon steel piping system in the utilidor duct. Thermal insulation prevents natural gas from cooling in severe polar climate. CSA

Z276 standard applies upstream of the outlet flange of the send-out meter, and the NFPA 54 National Fuel Gas standard applies downstream of the outlet flange. The main send-out header downstream of the spec break and upstream of the interface point is a 4" diameter, schedule 40, 275 psig MAOP carbon steel pipe designed and constructed in compliance with NFPA 54 – National Fuel Gas Code specifications. The MAOP for the pipeline is 275 psig and the operating temperature range is 10-50 °C and conforms to the requirements of ASME B31.8. The pipe in the utilidor will be painted, wrapped and cathodically protected since the utilidor can have standing water. All above ground natural gas lines after the vaporizers shall be insulated and the designed for -55C ambient conditions.

9.0 Not Used

10.0 Fire Protection and Suppression

Fire Protection and Response Philosophy is based on regulatory requirements and industry best practices that prescribe proven methods to minimize the likelihood of a fire incident and potential consequences. Emphasis is placed upon prevention of releases of flammable fluids to the atmosphere and minimization and control of ignition sources in the vicinity of the process, storage and transfer areas as the primary means to prevent a condition where a fire could occur.

A number of measures have been integrated into plant design to ensure that this fire philosophy is met:

- ESD/Isolation (SIS) and Control Systems to safely isolate and shutdown equipment and piping.
- Hazard detection (fire, gas & low temperature) systems in process, storage, and transfer for early detection and reporting.
- Secondary Containment in LNG storage and transfer areas to limit the surface area of potential LNG spills.
- Incident Command Structure to effectively respond to an incident.
- Communications systems (General Alarm, 2-way radios, and other communication systems).
    - Contractor shall provide alarm system within LNG Area, i.e., broadcast sirens and beacons.
    - YEC will provide 2-way radios.
- Fire Suppression extinguishers (to be provided by Contractor).
- Fireproofing of critical structures located in process areas.
- Impounding surfaces to be coated with perlite concrete to minimize LNG spill vaporization.
- Designated restricted areas and management controls to minimize potential ignition sources in areas where flammable gas may be present.
- Operating procedures and safe work practices.
- Procedural training and drills for plant personnel
- Preventative and corrective maintenance to make certain equipment is working properly and available in the event of an emergency.

Process areas, LNG storage, truck unloading, utility areas and buildings will have fire detection/alarm systems strategically located for early detection and reporting.

The most effective measures to prevent fire and subsequent damage are early detection, reporting the incident, timely isolation/depressuring to stop the release, and fire suppression. Given the nature of a natural gas/LNG fire, do not attempt to extinguish an LNG fire with water as this increases LNG vaporization and exacerbates the fire. Class B portable fire extinguishers will provided by Contractor.

11.0 Security Provisions

The LNG facility will be completely fenced on its east, south and west borders by a 7 foot high security fence topped with 1 foot of razor wire. The northern area that has a common border with the power plant will not be fenced. The LNG highway tanker unloading area is separated from the process area with an internal boundary fence to divide the unloading area from the process area. As detailed earlier, two motorized gates will be installed. The security fence will be installed by others.

Closed–circuit (CCTV) television system will be used for monitoring facility, with the aid of lighting. All CCTV monitoring cameras are connected to the existing control room for camera monitoring. The CCTV system will be installed by others.

Warning signs will be placed at regular intervals on the access way and the main entrance.

12. Process Control

12.1 Overview

The LNG Area, as well as all equipment within the YEC compound, will be controlled and monitored from within the existing control room, except for the HMI at the truck unloading area discussed above. Also, all motorized equipment can also be started and stopped locally.

Contractor will provide all control hardware. This includes the hardware designed to control the process equipment and the hardware described in Appendices B and C to control the safety systems within the LNG area. All control hardware for the LNG Area will be installed in the new substation located approximately 100 meters north of the LNG storage tanks. The conduit between the LNG Area and the substation will be installed by others; Contractor will inform the YEC project manager as to Contractor's requirements. Contractor will install the communication wiring between the LNG area and the substation within the conduit installed by others.

The communication cables will be routed between the LNG Area and the new substation in the utilidor. Contractor will provide all hardware and software necessary to operate and control the LNG Facility. Contractor will also provide a remote transmitting unit, necessary termination connection points inside the substation and the logic necessary for the hardware provided by

Contractor to communicate with the YEC SCADA system ("SCADA"). The YEC project manager will use the information provided by Contractor to connect the LNG Area system to the SCADA system.

12.2 Control Power

12.2.1 24V DC

Redundant 24V DC systems will be provided for all Contractor supplied equipment in the substation as required. This system will include dual chargers and 100% rated dual batteries, arranged so that a failure or removal from service of any one component will not interrupt service.

12.2.2 Back-up Power Supply

Instrument electrical power supply system will be provided to ensure appropriate level of security for the functions the instrumentation it serves.

All control hardware will have suitably sized UPS for 120V AC circuits.

Power requirements will be per manufacturer's recommendations.

12.3 Description of the SIS

A new Safety Instrumented System (SIS) will provide safeguards for the new plant and is further described in detail in Appendix C.

The specific objectives for the SIS system are to provide a reliable means to:

- Sense automatically any abnormal operation or equipment /process condition
- React automatically to this condition by shutting down and/or isolating the installation, preventing any consequential effects of the abnormal condition
- Provide engineering facilities to configure, modify and maintain the SIS system online
- Accept non-safety commands from the SCADA system for SIS, e.g., reset commands, maintenance overrides
- Provide SIS status information to the SCADA system
- Handle auto start-up overrides
- Interface to critical alarm enunciator

Data from the SIS are viewed through the SCADA HMI.

12.3.1 ESD System

An emergency shutdown system will be provided which is designed to sectionally isolate the sections of the LNG Area in the event of an emergency.

An emergency may be defined as:

i) A significant release of flammable gas or liquid or a significant fire
ii) A developing situation liable to generate i) above.

Primarily, the ESD system is a manually initiated shutdown system (MISD), where the manually initiators are strategically located pushbuttons or switches (usually in the control rooms or local to areas they serve). ESD's can however, also be generated by other instrumented initiators, where the consequence is foreseeably i) above.

The initiators generate actions, which are primarily the closure of dedicated emergency shutdown valves, the stopping of motors and the starting of hazard control equipment. The initiators may also generate subsidiary actions, e.g. closing routing or control valves, but these are not the primary mechanisms. It is expected that the subsidiary actions will be developed further in detailed design.

The intent of ESDs is generally a combination of the following requirements:
i) Isolation of inventory
ii) Sectionalization of Plant
iii) Stopping flow of flammable liquid or gas to a fire (high fire risk areas).

As a route to these goals it is conventional to break a site into zones. In this case the zones can be designated as
i) Tanker unloading area including storage tank inlet
ii) Process area including storage tanks outlet

Each of these zones is provided with a zone shutdown. The LNG Area is provided with 2 ESD levels.
These are

ESD-1	Tanker unloading area shutdown
ESD-2	Process area shutdown

If there is detection of a flammable gas or liquid spill in the tanker unloading area, then the ESD-1 will shut down the unloading activity but not shutdown the sendout to the power plant. If there is a flammable gas or liquid spill in the process area, then the entire LNG facility will shutdown. If there is a fire detected in any part of the LNG area, then the entire LNG facility will shutdown.

Emergency shutdown valves are tight shut-off fire safe valves. Valve actuators are spring loaded air fail close, which are also provided with a fusible link to ensure that they close the valve in the event of a local fire.

All ESDVs will close in less than 5 seconds. Where necessary in order to limit water hammer, 2-speed valve closure may be utilized. (To be determined in detailed design).

ESDVs can only be reset in the field using local field mounted switches.

The ESD system is designed for high integrity.

12.4 F&G Hazard Detection Safety Systems

12.4.1 F&G Hazard Detection

CSA Z276 requires that all areas that have a potential for flammable concentrations of LNG or flammable gas releases be monitored for flammable gas concentrations and ignitions. The F&G Hazard Detection and Control systems form part of the safety systems alongside the Emergency Shutdown system.

The F&G detectors installed in specific locations where the possibility of such occurrence will detect gas leaks. Flame, heat and smoke detectors are installed as per applicable codes and standards. Emergency manual call points are provided, as well as sirens and beacons to alert others of potential emergency situations. Detectors will automatically activate F&G Alarm systems upon reaching their calibrated set-points and will initiate LNG facility shutdown systems. The control room operator will be required to take the appropriate actions to safeguard the equipment. F&G system audible and visual alarms will be provided to alert plant operators of F&G system activation. Flashing beacons, audible alarms and automatic fire suppression systems will be installed for this use.

Appendix B contains a detailed specification for the F&G system.

12.4.2 Closed Circuit Television (CCTV)

Closed circuit television (CCTV) system cameras will be installed by others.

12.4.4 Hazard Detection System Locations

Suitable detectors for each area take into account the type of hazard likely to occur, and the environment in which they are located. Smart area monitors with splashguards and single person calibration features are to be provided for monitoring flammable gases within the facility. Sensors will be located in the LNG storage tank area, LNG vaporization area, and LNG truck unloading area. Combustible gas detectors, smoke detectors, and multispectral infra-red (IR) fire detectors are provided with local status indicators and are self-checking. A portable calibration equipment kit will be provided for maintenance field verification and calibration needs.

12.4.5 Detector Types

12.4.5.1 Flame Detectors

Flame detectors are designed to cover all areas where LNG spills, gas leaks and ignition sources are most likely to occur. Smart Infra-Red (IR) multispectral optical detectors will be used for flame detection purposes. Solar blind IR detectors are used in areas of high hydrocarbon content where rapid flame growth would be the expected fire characteristic. Detectors provide combined response increased reliability by its increased false alarm immunity. Therefore, smart Infra-Red (IR) multispectral optical detectors are used throughout the facility, unless a specific application requires a different detector.

12.4.5.2 Flammable Gas Detectors

Flammable gas detectors are designed to cover all areas where there is a potential of LNG or natural gas release. There are two (2) common types used throughout the facility; Point, and Line of Sight optical flammable gas detectors. The Point detector measures concentration of gas at the sampling point of the instrument using a resistive catalyst element. The Infrared Line of Sight detector otherwise known as the Open Path Optical beam detector, measures the average concentration of gas along the path of an optical beam by spectral analysis.

12.4.5.3 Smoke Detectors

Smoke detectors are provided in buildings where early detection of smoke is critical to safeguarding the equipment in the building.

12.4.5.4 Heat Detectors

Heat detectors are used for the detection of fires where the rate of heat generation is high and the quantity of heat generated is large, usually in areas where flammable and combustible materials are handled or stored and operating conditions are inappropriate for installing smoke or flame detectors. Various types that may be used according to their different features and in different locations include the Fixed Temperature, Rate Compensated, Rate of Rise, Pneumatic and Linear Heat detectors. Sensors will be located throughout the LNG facility.

12.4.5.5 Low Temperature Detectors

Low temperature sensors are used to detect LNG releases in secondary containment and impoundments. Temperature probes are located in the impoundment basin to detect leakage and alert operators and to prevent start-up of the impoundment basin storm water pumps in case of an LNG spill or freezing temperature.

12.4.5.6 Public Address and General Alarm System

The facility General Alarm beacon/strobe lights, sirens, pre-recorded announcements, and real–time instructions are used when an emergency is declared in the LNG facility. The visual lights provide confirmation to the audible general alarms and announcements. These beacon/strobe lights remain activated until the “All Clear” is declared. There are various strobe/beacons including the facility General Alarm beacons, which LNG facility operators must immediately recognize as abnormal conditions.

12.4.5.7 Detection Equipment Matrix

The following table gives a basic illustration of the locations and detection requirements that will be developed in detailed design.

LNG Area Fire Hazard System Matrix	Flame UV/IR Detector	Flammable Gas Detector (point)	Flammable Gas Detector (beam)	Low Temp. Leak Detector	Smoke Detector	Heat Detector	Manual Alarm Call Point
Equipment Location							
LNG Plant Storage (5 Tanks)	5	10	5			10	1
Vaporizer Area	2	2					1
BOG Compressors	1	2				2	1
Send Out Pumps Area	2	2					1
Impoundment Basins	1	1		1			
Gas Metering Package		1					
Truck Unloading	2	2	1				2
Totals	13	20	6	1	0	12	6
				Total			58

APPENDIX A

Not Used

APPENDIX B
Fire and Gas (F&G) system description

1 SCOPE

1.1 Introduction

This specification sets out the design, manufacturing and operating requirements of a microprocessor based Fire and Gas (F&G) system suitable for installing in the existing control room.

1.2 General

The LNG Area F&G system shall consist of a dedicated, independent, stand-alone F&G system to monitor and control all F&G safety related parameters.

The F&G and SIS systems shall operate and may interact as defined in the F&G Cause and Effect diagram.

F&G initiation causes shall be reported and alarmed at the SCADA for printing. The SCADA shall log all override positions.

Voting logic, including primary sensors, shall be employed. The logic shall be derived from SIL determination procedure.

The Fire and Gas detection system shall receive inputs from discrete addressable end devices such as thermal detectors, smoke detectors, manual alarm call points, combustible gas detectors, fire pump start controls, and ultra-violet (UV) / infra-red (IR) fire detectors as required to protect life and equipment. Combustible gas detectors, and ultra-violet (UV) / infra-red (IR) fire detectors have local status indicators.

The F&G system shall be utilized to provide terminal safety shutdown and other related functions that include the following:

(1) Shutdown by manual operator input.
(2) Interface for maintenance by-pass switches via [MM].
(3) Output to PA and beacon alarm system.

The panel shall be freestanding, floor-mounted, suitable for a safe environment, and have a minimum of NEMA 4 certification. The panel shall be equipped with cooling fans where required for proper ventilation.

For test equipment, the design shall include an electrical outlet inside the cabinet. The outlet shall be powered independently from the UPS.

All interconnecting wiring within the cabinet shall be the responsibility of Contractor.

All wiring shall be segregated/color-coded according to input or output and voltage: levels and type (AC or DC).

All 24 VDC power distribution required within the cabinets shall be the supplier's responsibility. These power supplies shall have a redundant design.

All interconnecting cables shall be tagged at both ends with cable/plug numbers and cabinet numbers. Wiring shall be tagged at both ends (where applicable) with tag number using heat-shrink sleeve-type markers.

Terminal blocks shall be compression type. Terminals shall be clearly identified.

Jumpers shall be shunts on terminal strips or bus bars.

All fusing terminals shall be compression type.

All wire shall be stranded copper. Wire sizes shall be selected to comply with current electrical design requirements.

1.3 Expansion and Spares

SIS and F&G Systems shall be designed so that after commissioning the following evenly distributed capacities shall be available at each location:

- I/O Modules – 10% installed, wired and fully functional spare I/O of all types.
- I/O Racks – 20% fully wired spare rack space (modules not installed).
- Terminal Blocks – 25% spares.
- System Cabling – 25% spare pairs.
- Fiber Optic (FO) – 100% spare fibers.

Loading Criteria:

The system shall be designed so that after commissioning the loading criteria of the following shall not exceed 70%, including spare capacity and spare space:

- Processing capacity and/or memory.
- Communication network.

- Hard disc utilization.

The system power-supply units shall not exceed 75% loading, including spare capacity and rack space.

Expansion Requirements:

The system shall be capable of expansion at a future date without major changes to device and network configuration. For guidance, 50% increase shall be assumed for total I/O and total nodes on any SIS, F&G, process control, etc. Local Area Network (LAN) after plant start-up.

1.4 Operator Interface

The operator interface shall comprise a mosaic tile panel located at the Central Control Room desk.

F&G pushbuttons shall employ normally closed contacts in the plant healthy state, i.e. open to trip. Each pushbutton shall have logic-driven illumination indicating the state of the switch, and shall have a guard to prevent inadvertent operation. Logic reset pushbuttons shall be normally open contacts, i.e. close to reset.

The illuminating pushbuttons shall be connected to a common-lamp test system.

At each location the SIS-to-F&G panel interface shall be hard wired with the fire/gas signal normally closed, open to initiate SIS action.

1.5 Inhibits and Overrides

F&G initiators and outputs shall be provided with “override” or “maintenance bypass” switches to allow faultfinding, field-testing and “start-up overrides” as defined on the F&G Cause and Effect Diagrams. Maintenance bypass switches shall be of the key-switch type, with lighted indicators on the system cabinet.

Actuation of inhibit mechanisms shall suppress automatic logic action from the related channel, but shall not suppress the alarm function to the SCADA. Actuation of override mechanisms shall only prevent the final related output from being tripped. All inhibits and overrides shall be logged and displayed on the system printer. Actuation of one or more individual override mechanisms shall cause a common alarm to occur at the SCADA. All inhibit and override switches shall have identical keys, which shall be retained in the key lock while the override is active.

2 FIRE AND GAS EQUIPMENT REQUIREMENTS

2.1 The purpose of the F&G installation is to prevent the occurrence of any physical situation that can potentially cause loss, damage or undesirable effects on the plant, equipment, product, raw material, property, people and the environment.

2.2 The F&G equipment installation shall be independent of other plant instruments and instrumentation systems, so that any faults and failures on F&G instruments and systems shall not cause a corresponding failure or fault in the integrity or operability of the F&G system. If possible, unavoidable exceptions to this principle shall cause the F&G system to operate and shut down the appropriate section of plant, i.e. shall “fail safe”.

2.3 Essentially, the SIS/F&G system of the combined plant and dock areas comprise system hardware, firmware and software interlinked by robust communication networks. The system integrity shall be such that reliability measures will be addressed to achieve at least 99.99% availability of the overall scheme.

The system shall be fault-tolerant microprocessor-based design that protects the controlled process from intermittent, transient, and permanent system faults. Any single fault shall not degrade system safety or functionality or influence the operation of the controlled process.

Any single fault must be repairable on-line without interruption to the process.

Any fault occurring in the system must be alarmed with indication of exact location of the faulty component.

The system must be designed such that to be unaffected by common mode failures.

Any fault resulting in a system failure shall be such that all failure modes are fail-safe to the OFF or OPEN state. This shall include all module removal and cable faults.

There shall be no single failure point that could affect more than one channel. Failure of any single active component supplied within the system shall not cause a shutdown action, and during such a failure, the system shall remain on-line and shall maintain the process-safety protection. Additionally, the system shall accommodate a means for alarming the fault.

The individual inputs of any point shall be brought into a terminal strip and shall be independently powered from the inputs of the other two points of the voting system. No one fuse or power failure is to affect the power or controls of the other voting components.

The design shall clearly show the system’s actions and responses upon the failure of one or more of its redundant channels. Diagnostics shall indicate each failure

level and provide mechanisms for user-initiated shutdown within each failure mode.

It shall be possible to replace and/or repair any faulty system module without degrading the safety of the system. Repair shall not require disruption of the scanning process or “freezing” of the output states; the transition to the healthy module shall be bump-less, i.e. no loss of control. No operator action other than simple mechanical replacement of modules shall be required to restore the system to normal operation.

Input and output signals shall be voted independently. Output signals shall be designed as de-energized to trip.

2.4 The design principle for all F&G equipment shall be “fail safe”:

- Electronic modules shall be self-checking and shall “fail safe” if a fault is detected.
- Initiating contacts shall be normally closed, but open on shutdown.

2.5 The design and installation of every component and part of the F&G installation either shall enable it to be tested or shall have its operability and integrity be subject to continuous monitoring during normal operation of the plant. Failure shall be fail-safe and shall alert the operator.

Test facilities shall, wherever possible, not prevent or impair the operation of the F&G system; if this cannot be achieved, then a control-room system alarm shall operate whenever an input or output is detected or bypassed. Generally, all the F&G system alarms shall remain operable during testing.

2.6 The design basis for the majority of electrical instruments in hazardous areas is explosion proof. Instruments shall be supplied with SMART capability to enable systems and maintenance diagnostic interrogation. It should be noted that SMART instruments adopted for F&G service should have selected functions permanently disabled.

2.7 The system as a whole shall be certified by TUV to SIL-3 classification or by any other internationally recognized body subject to approval by the client. An abridged-TUV test report of the proposed system shall be furnished by the supplier for acceptance by the client. Failure to provide such a report shall render the proposed system unacceptable.

Instrument loops for the facility shall be engineered to meet the target SIL for hazard assessments. Validation shall be obtained for Safety Instrumented Systems adopting quantitative and qualitative methods detailed in IEC-61508/61511.

Hazard analysis studies will specify requirements for instrument integrity from SIL-0 to SIL-3, the latter being the most onerous to achieve with regard to instrument engineering capability. Contactor shall assess the requirements so that the lowest SIL is achievable while adopting appropriate alternative methods of risk mitigation with instrumented loop function.

Essentially, the Control System will contain SIL-0 assessed and validated loops. While the SIS system will contain all designated loops and validated loops greater than SIL-0, some SIL-0 loops may be specified for SIS system connections if the loop requires, for example, a high-availability requirement.

3 FIRE AND GAS FIELD EQUIPMENT

3.1 General

All devices shall be suitably certified for the hazardous area classification. All device bases shall incorporate NPT cable entries and suitable terminations except where individually specified otherwise, and shall be supplied fitted with suitable blanking plugs.

Detectors fabricated from materials likely to be damaged by accidental impact shall include adequate protection against such damage.

Detectors shall be capable of withstanding supply voltage fluctuations from 85% to 110% of rated voltage without affecting detector sensitivity, prompting false alarms or indicating faults.

All types of detectors shall be capable of giving fault indication at the equipment cabinet.

Detectors shall be fitted with line monitoring components, as applicable, prior to dispatch.

The types of detectors and alarms to be employed throughout the site may include but is not limited to the following:

- Low Temperature Detector
- Flammable Gas Detector
- Smoke Detector
- Heat Detector
- Flame Detector
- Manual Alarm Callpoints (MACs)

3.2 Heat Detectors (Double Thermistors)

3.2.1 Indoor

Combined rate-of-rise/fixed temperature and fixed temperature heat detectors shall be used as required. The preferred type of detection is the rate-compensated/fixed temperature derivative.

Detectors shall be located in areas where fire will cause a rapid rise in temperature.

Detectors for fixed temperature applications shall be set to 60ºC and located in areas where rapid changes in ambient temperature may be expected.

Detectors shall incorporate a latching LED indication, which indicates the detector is in alarm condition.

The sensor head assembly shall be constructed so that the base may be installed without the sensing element.

Detectors shall have plug-in capability and be suitable for flush, recess or surface mounting applications.

3.2.2 Heavy Duty (Outdoor)

Heavy-duty heat detectors shall be located in areas where fire will cause a rapid rise in temperature. Set temperature shall be 70ºC.

Heavy-duty heat detectors shall be hazardous area certified.

Heavy-duty heat detectors shall have bodies of stainless steel or other non-corrosive material and be protected against effects of the environment.

3.3 Smoke Detectors

3.3.1 Photo-electronic

Smoke detectors shall be of the photo-electronic type responding to products of combustion. Smoke detectors shall be located in areas where the first indication of fire will be smoke or other products of combustion without an immediate rapid temperature rise.

Smoke detectors of the laser optical type are preferred. Such devices, however, must conform to the relevant sections of the governing acts concerning radioactive output limitations for use in occupied areas. To prevent false alarms or malfunction caused by small insects entering the device, detectors shall include fine gauze filters.

3.4 Flame Detection

3.4.1 Infrared Flame Detection

Infrared flame detectors shall respond to the radiant energy from a fire. They shall incorporate a detecting device that responds to radiation in the range from 1850 Å to 2450 Å. They should be insensitive to direct and reflected sunlight and to normal artificial light.

The detectors shall be arranged so that they do not "see" direct or reflected radiation from arc welding to minimize spurious alarms.

The detectors shall have a 90° cone of vision and shall be capable of detecting a 750mm natural gas plume fire at 24m.

The detectors shall incorporate an automatic lens monitoring system to warn of deterioration of the optical qualities of its lens, which may be caused by dust, dirt or condensation.

The detectors shall either be certified as intrinsically safe or be in an explosion proof enclosure of NEMA 4X minimum. Intrinsically safe type shall only be provided if explosion proof is not available.

The detector body shall be stainless steel or aluminum with magnesium content less than 6% and epoxy paint finish at least 150µm thick. The fixing bracket shall be stainless steel or other non-corrosive material and incorporate a swivel to allow adjustment of detector orientation.

The controller shall monitor the status of the detectors and shall initiate the lens-monitoring test on a regular basis.

There shall be a minimum of two detectors monitoring an area.

Infrared flame detectors shall have local status indicators.

3.5 Flammable Gas Detectors

3.5.1 Point Type (Infrared principle)

This type of flammable gas detector shall be installed at locations where gas can be confined and can be concentrated to explosive levels, e.g. HVAC intake ducts. They shall also be installed close to where potential leak sources are known.

Each detector shall be assigned two alarms: 10% and 40% Lower Flammable Limit (LFL).

The sensor head shall be stainless steel or other non-corrosive material.

For measurement in HVAC ducts, the contractor shall offer duct-mounting kits; test gas inlets, including tubing and application points; and provide limitation details such as air velocity.

Flammable gas detectors shall have local status indicators.

3.5.2 Open-Path (Line-of-sight) Infrared Type

This type of detector shall be installed to detect the presence of combustible gas. Each detector shall comprise an optical-transmitter unit and a receiver unit. The detector module shall provide blocked-beam alarm, low-visibility alarm and fault warning. Automatic testing and diagnostics facilities shall be built in.

The detectors shall be explosion proof.

The sensor shall be stainless steel and be provided with a means of mechanical protection.

Each detector shall be assigned two alarms: 10% and 40% Lower Flammable Limit (LFL).

Where the potential leak is LNG or cold gas, the detector shall be mounted at low level (approximately 300mm above grade).

The detector shall be guaranteed for a service life of at least two years.

Open-Path (Line-of-sight) Infrared Type detectors shall have local status indicators.

3.6 Low Temperature Detectors

This type of detector shall be installed at locations where LNG leaks are expected to collect, i.e. LNG spillage channels. These detectors shall be suitable for use in an LNG environment where the sensor temperature will be -168°C.

The detector shall either be certified as intrinsically safe or be in an explosion-proof enclosure. Intrinsically safe shall only be provided if explosion proof is not available.

The sensor shall be stainless steel or other non-corrosive material and be provided with a means of mechanical protection.

The design shall include a suitable detection device for this application, such as a conventional temperature transmitter/RTD element.

3.7 Manual Alarm Call Points (MAC)

3.7.1 Indoor

Manual Alarm Call points shall be the break glass type.

The alarm signal shall remain until the glass is replaced and the system reset.

The key-operated, or similar, test facility is to be provided to allow testing of the circuit without dismantling or breaking the glass.

Manual Alarm Call points shall have local status indicator.

3.7.2 Heavy Duty (Outdoor)

Heavy-duty MACs, generally, shall be as indoor type except for the following points:

They shall incorporate a red LED status indicator.

They shall have bodies of 316 stainless steel or GRP and be protected against the effects of the environment.

They shall be hazardous area certified.

3.8 Fire Alarm Sounders

Local audible alarms shall be rated for continuous use and have a minimum sound pressure level of 85dBA, adjustable to 113dBA, at a distance of 3 feet.

The form of the audible signal shall be selectable for continuous, intermittent and whoop/sweep with adjustable volume and frequency.

The sounder enclosure shall be hazardous area certified. The sounder shall be suitable for surface or pole mounting.

4 DESIGN

4.1 Fire and Gas Mimic Panels

4.1.1 The Fire and Gas mimic panel for the LNG Area shall be located in the existing central control room.

4.1.2 On the front of the mimic panel, a mimic diagram representing geographical areas of the LNG Area shall be provided.

4.1.3 The mimic diagram shall show different areas of the LNG Area divided into zones. The system shall monitor the status of all automatic and manual alarm devices and extinguishing systems. The mimic panel shall indicate the digital address of any alarm or fault. For each zone the following common flashing lamps shall be provided as a minimum:

- Flame detectors.
- Manual break glass units.
- LNG spill detectors.
- Hydrocarbon gas detectors.
- Smoke detector within a building.

4.1.4 The gas-detection receiver modules and IR flame-detector zone control units shall be flush mounted on the front of the panel. Common audible warnings for any zone shall be provided on the panel.

4.1.5 The fire-and-gas-detection system-lock hardware shall be mounted inside a cabinet in the equipment room. The ultimate logic of the LNG Area F&G alarm system shall be developed from the plant safety philosophy. The fire and gas logic system shall be designed to continuously supervise all field detectors for open or short circuit of the cabling by means of the provision of end-of-line resistors or manufacturer standards, and alarm any fault on the OWS and Mimic Panel.

4.1.6 In addition to standard display and alarm functions provided by the fire and gas detection modules, custom-built logic to initiate the shutdown and the fire-fighting pumps shall be designed. The F&G logic system shall be designed such that the whole system can be fully tested without activating any secondary firefighting systems.

4.1.7 For each zone, the following lamps shall be provided as a minimum:

(1) One common flashing lamp for all flame detectors within a zone.
(2) One common flashing lamp for all manual break glass units within a zone.
(3) One common flashing lamp for all LNG spill detectors within a zone.

(4) One common flashing lamp for all hydrocarbon gas detectors within a zone.

(5) One common flashing lamp for all smoke detectors within a zone.

(6) One common flashing lamp for all high temperature detectors within a zone.

(7) One fault/malfunction lamp common for all types of devices within a zone.

Additionally, lamp test, alarm acknowledgement and reset push buttons shall be provided.

4.1.8 The various fire-and-gas-detection receiver-module control units shall be flush mounted (19”racks) on the front of the panel and below the mimic diagram.

4.1.9 Three types of audible warnings shall be provided on the panel:

(1) One common fire bell that will be activated if any of the IR flame detectors detect fire, or if manual break glass units or smoke or high temperature detectors activate in any zone.

(2) One common chime that will be activated if any of the LNG spill detectors detect LNG leakage in any zone.

(3) One common hooter/klaxon that will be activated if any of the hydrocarbon gas detectors sense HC gas.

4.1.10 The fire-and-gas-detection system-logic hardware shall be mounted inside the panel.

4.2 Fire and Gas Alarm Logic

4.2.1 The ultimate logic of the LNG terminal Fire and Gas alarm system shall be developed from the plant safety philosophy. This document states basic requirements only.

4.2.2 The fire and gas logic system shall be designed to continuously supervise all field detectors for open or short circuit of the cabling by means of the provision of end-of-line resistors or manufacturer standard, and alarm any fault on the alarm annunciator and/or SCADA.

4.2.3 The fire and gas logic system shall be designed to be automatic. Control modules shall display Normal-Alarm-Fault status of each field device and report alarm or fault status via the alarm annunciator. F&G alarms shall be “First Out” type and shall be recorded and stamped in the Sequence of Events Recorder (SER) and Historian.

4.2.4 In addition to standard display and alarm functions provided by the fire and gas detection modules, the F&G system shall provide custom-built logic to initiate interfaces with other systems.

4.2.5 The fire and gas logic system shall be designed such that the whole system can be fully tested without activating any secondary firefighting systems.

4.3 Fire Detection System

4.3.1 For a single alarm, the Operator shall decide whether to initiate a manual shutdown. The fire detection system shall be designed to cover all process areas and service buildings, including the following locations:

- Main Control Room
- Marshaling Rack Room
- At tanker unloading area
- In LNG storage areas and impounding basin
- In the LNG storage tank pump, vaporizer, BOG compressor and metering area

4.3.2 A control room based surveillance system using CCTV cameras at the LNG tanker unloading area, impounding basin, tankage and process area shall be provided by others to allow constant monitoring of high-risk areas, and shall be designed as an integrated web-based system with the network and control systems.

4.3.3 Suitable detectors shall be selected for each area while taking into account the type of fire likely to occur and the environment in which they are located. The following types of detectors shall be employed in the above referenced areas:

(1) Flame Detectors – Flame detectors shall be designed to cover all areas where an LNG fire is foreseeable. Infrared (IR) or combined UV/IR detectors may be used for flame detection purposes. Specified IR detectors shall be solar blind and located so as not to react to IR radiation from any flaring operations.

(2) Heat Detectors – Heat detectors of the double-thermistor type shall be utilized to monitor for fire around the storage tanks.

(3) Smoke Detectors – Photoelectric type smoke detectors shall be specified for buildings.

4.4 Gas Detection System

4.4.1 A combustible gas-in-air detection system shall be designed, and the gas detectors shall cover at a minimum the following locations:

- In BOG compressor area
- In LNG pump area
- In LNG vaporizer area
- Along route of all lines carrying LNG
- Metering station
- Truck unloading station

4.4.2 The gas detectors shall initiate the fire alarm system. For a single alarm, the operator shall decide whether to initiate a manual shutdown.

4.5 Unit Logic

4.5.1 Logic for Manual Break Glass Units

Manual break glass units shall be mounted around the protected area and grouped into zones. An alarm signal from any unit shall initiate the following:

(1) Visual and audible alarms on the mimic panel in its zone of origin and digital address of the sending unit.
(2) A common alarm on the SCADA.
(3) A remote alarm contact.
(4) Activation of the common fire bell.
(5) Activation of other systems as per the F&G cause and effect diagrams.

4.5.2 Logic for IR Flame Detectors

IR flame detectors shall be grouped into zones. An alarm signal from any detector within a zone shall initiate the following:

(1) Visual and audible alarms on the mimic panel in its zone of origin and digital address of the sending unit.
(2) A common alarm on the SCADA.
(3) A remote alarm contact.
(4) Activation of the common fire visual and audible alarms.
(5) Activation of the other systems as per the F&G cause and effect diagrams.

4.5.3 Logic for LNG Spill Detectors

LNG spill detectors shall be grouped into zones. An alarm signal from any detector within a zone shall initiate the following:

(1) Visual and audible alarms on the mimic panel in its zone of origin and digital address of the sending unit.
(2) A common alarm on the SCADA.
(3) A remote alarm contact.
(4) Activation of the common chime.
(5) Activation of the SIS, etc., as per the F&G cause and effect diagrams.

4.5.4 Logic for Hydrocarbon (HC) Gas Detectors

HC gas detectors shall be grouped into zones. An alarm signal from any detector within a zone shall initiate the following:

(1) Visual and audible alarms on the mimic panel and digital address of the sending unit.
(2) A common alarm on the SCADA.
(3) A remote alarm contact.
(4) Activation of the F&G visual and audible alarms in the control room.
(5) Activation of secondary systems, as per the F&G cause and effect diagrams.

4.5.5 Logic for High Temperature Detectors

High-temperature detectors shall be grouped into zones. An alarm signal from any detector within a zone shall initiate the following:

(1) Visual and audible alarms on the mimic panel and digital address of the sending unit.
(2) A common alarm on the SCADA.
(3) A remote alarm contact.
(4) Activation of the common fire bell.
(5) Activation of secondary systems, as per the F&G cause and effect diagrams.

4.5.6 Logic for Smoke Detectors

An alarm signal from any unit within a building shall initiate the following:

(1) Visual and audible alarms on the mimic panel in its zone of origin and digital address of the sending unit.
(2) A common alarm on the SCADA.
(3) A remote alarm contact.
(4) Activation of the common fire bell.

(5) Activation of secondary systems, as per the F&G cause and effect diagrams.
(6) Building heating system shutdown

Note: Control and Electrical Buildings

Control and electrical buildings will have their own fire alarm and extinguishing systems and fire alarm control panel(s) covered under a separate specification.

The following interface signals shall be available from the Control and electrical buildings the panels and the main F&G system:

(1) Fire-detected alarm.
(2) Common manual break glass alarm (M.C.P. [Manual Call Point]).
(3) Inert gas discharge.
(4) Malfunction alarm.
(5) Stop heater.

5 SYSTEM TESTING

5.1 General

Contractor shall obligate the supplier to perform a full program of inspection and testing in accordance with a comprehensive procedure, which shall be approved prior to implementation. All equipment shall be inspected and tested by the supplier prior to inspection by Contractor and YEC's representative.

All system tests shall include the cabinet, remote annunciation lamp box and remote switch panel interconnected with the system cord sets.

The supplier, at the end of the manufacturing phase, shall perform his own inspection to ensure each system is operational and complete in all respects. All temporary facilities for the test program shall be supplied and connected by the supplier. All temporary work shall be of a good and safe engineering standard.

5.2 Supplier's Test Equipment

The supplier shall supply all calibration, testing and simulation instruments required to perform the testing to a standard approved by Contractor.

All test equipment provided by the supplier shall be covered by up-to-date test certificates.

The test equipment supplied shall include but not be limited to the following:

- Specialized test equipment for testing individual cards or components.
- Interconnecting cables for connection of all test equipment, including jack sockets, plugs, etc.
- Simulator (if required) to simulate the final on-site configuration. This unit shall be suitable for the system-functional testing and shall generally comprise lamps, switches and 4-20mA signal simulators.

5.3 Inspection and Testing Documentation

The supplier shall produce a comprehensive test procedure and prepare a manual of test record sheets for use during works testing and onsite pre-commissioning test.

The manual of test record sheets shall be of such a format as to allow system test personnel to work through the tests required and to record all the results as the tests proceed, including all failures and subsequent re-testing. Any printouts forming part of the tests shall be included in the manual. This manual shall be maintained through all stages of testing on the equipment.

Prior to commencement of any factory or site test, all required test procedures, record manuals and documentation requirements shall be available in a fully updated format at the appropriate test venue.

5.4 Stages of Testing

The hardware and software to be supplied shall be tested in the following stages:

- Hardware Tests
- Electrical Tests
- Heat Soak Tests
- Factory Acceptance Tests (functional) (FAT)
- Site Tests (SAT)

5.4.1 Hardware Tests

The following hardware tests shall be completed by the supplier prior to witnessing factory tests. A detailed test program shall be developed. The supplier shall test and confirm that all equipment within the system complies with the design requirements.

The supplier shall provide all test equipment as required by the test program for the duration of the test. The tests shall include the following equipment as a minimum:

(a) Input modules.
(b) Output modules.
(c) Logic modules.
(d) General electrical installation.
(e) Bypass and test facilities.
(f) Switch inputs and lamp outputs.
(g) Event recording facilities and communications data link.
(h) System fault alarm facilities.

5.4.2 Electrical Tests

Appropriate electrical systems shall be tested for insulation resistance, polarity correctness, and continuity. To prevent damage, low voltage equipment operating at “signal” voltage levels shall be disconnected as necessary and reconnected prior to functional tests of the system.

Grounding shall be tested for faults and continuity.

All terminations, glands, junction boxes and other electrical equipment enclosures shall be inspected for correct application assembly and closure.

The equipment shall also be checked to demonstrate the following:

- Power supply tests over stated limits (by contractor).
- Rejection of series and common mode noise on input signals.
- Immunity to mechanical vibration (supplier to advise maximum levels of shock and vibration that the equipment is able to tolerate).
- Immunity to RF interference (immune to signal strengths of 10 V/m over the 100 kHz to 1000 MHz range).

The above tests shall be repeated in the FAT.

The supplier shall, at his cost, satisfactorily rectify and re-test any faults found during the tests before undertaking the FATs.

5.4.3 Independent Testing

When supplier does not have the facilities for mechanical-vibration testing or RF-interference testing, it will be acceptable if satisfactory "type test" results for the equipment from a recognized independent testing body can be shown.

5.4.4 Heat Soak Tests

The system shall be operated by the supplier in its final onsite configuration with external interfaces simulated by supplier equipment for a minimum period of 48 hours. All inputs and outputs shall be simulated for this period.

The system environment shall be subjected to an elevated temperature of 60°C for the 48-hour period with a temperature cycle between 10°C and 60°C for a minimum of 10 cycles.

During the Heat Soak Test, the system equipment shall be fully exercised on a frequent basis. Fully loaded operating conditions shall be simulated at 12-hour intervals by exercising the logic via the simulated inputs.

Any part of the system failing, during the Heat Soak Test, shall be immediately replaced by the supplier at his expense, or be fault rectified. The Heat Soak Test shall restart as soon as the fault has been rectified. Time taken to undergo repair shall not be included in the test. All faults shall be adequately recorded in the test record.

5.4.5 Acceptance Tests

5.4.5.1 Before the equipment can be delivered to site, satisfactory performance of the whole system—simulating all inputs, outputs and foreign device communications and functionality—must be demonstrated to the satisfaction of Contractor and YEC representative.

Contractor shall prepare and submit detailed procedures and test sheets that cover the FAT, Integrated Factory Acceptance Test (IFAT) and Site Acceptance Test (SAT).

5.4.5.2 Factory Acceptance Test (FAT)

The full requirements of the test shall be defined in the "Factory Acceptance Procedure". Prior to advising the purchaser that the equipment is ready for the FAT, the supplier shall have completed its own internal full-functional tests.

These tests shall include the full systems and shall include a full 100% in-house test of the total I/O, including all the software modules. After this test, the supplier shall submit the internal test report to the contractor. The full FAT shall be witnessed by Contractor and YEC's representative.

On successful completion, the supplier and sub-vendors shall undertake the IFAT at SCADA supplier's facilities.

5.4.5.3 Integrated Factory Acceptance Test (IFAT)

The full requirements of the test shall be defined in the "Integrated Factory Acceptance Procedure". In addition to the supplier completing his own interface functional test, full equipment interface/integrated test with SCADA shall be carried out using the F&G system's processors. Integration testing shall cover the I/O simulation of F&G system all the way to SCADA HMI, SOE and history database. The F&G supplier shall be present while these tests are in progress until successful completion. The full IFAT shall be witnessed by the contractor and client's representatives.

5.4.5.4 Site Acceptance Test (SAT)

The full requirements of the test shall be defined in the "Site Acceptance Test Procedure". These tests shall prove that the various systems have not been damaged during transit, are installed correctly and function in accordance with the project design specification's requirements.

Fully integrated tests shall be performed, including all sub-vendor's equipment and systems.

5.4.5.5 General

Before the equipment/systems can be delivered to site, satisfactory performance of the whole systems—simulating all inputs, outputs and sub-vendor device communications—shall be demonstrated to the satisfaction of the purchaser/client or their representative.

The purchaser/client shall witness the above FATs prior to releasing the equipment for shipment. The supplier shall be responsible for conducting the tests and providing all necessary facilities, equipment and personnel.

5.4.5.6 Equipment required for test:

(a) Supplier's simulation and test equipment as specified in 5.2.
(b) All hardware sub-systems and components of the final design configuration.
(c) Sequence of events recorder communications receiver.

The system shall be fully operable and fully tested to the satisfaction of the supplier.

The tests to be carried out by the supplier prior to the Factory Test shall include a total system test, as detailed in Section 5.4.5.3 below, verifying all inputs and outputs for correct operation on both channels of the system, the operation of bypass switches, and the operation of external alarms and external communications interface.

5.4.5.7 System Tests

The system tests shall be carried out on the complete system. The following headings are recommended as a minimum requirement and shall be developed in detail during implementation of the test procedures:

1) Inspection of equipment.
2) Shock/Vibration Test.
3) Power supply variations.
4) Radio Interference Test.
5) Functional Tests including
   a) operator control panel functions;
   b) printed circuit board change over;
   c) operation of dual channels;
   d) operation and dual communication channels;
   e) operation of power supplies;
   f) failure and interaction between systems;
   g) systems diagnostic tests, including self-test facilities;
   h) system functional and fault alarms; and
   i) system grounding tests.

APPENDIX C
Specification for Safety Instrumentation System

Scope

Introduction

This specification sets out the design; manufacturing and operating requirements of a fail-safe fault tolerant microprocessor based Safety Instrumented System (SIS) suitable for installing remotely in the central control building.

General

The LNG Terminal SIS shall consist of a dedicated, independent, stand-alone safety instrumented system to monitor and control all critical and safety related parameters.

SIS Systems shall be located in the Central Control Room.

SIS initiation causes shall be reported and alarmed at the SCADA for printing. The SCADA shall also log all override switch positions.

Voting logic, including primary sensors, shall be employed. Shutdown signals shall be from dedicated process switches and analog signals. The logic shall be derived from the SIL determination procedure. Process switches shall only be adopted if analog signals are not available.

The SIS shall be suitable for Safety Integrity Level (SIL) 3 applications, configured for voting functions. The failure of any single component shall not result in a failure to correctly execute the required safety functionality. It shall, however, be possible to also apply simplex I/O when warranted by specific application considerations.

Manual override switches (MOS) shall be provided for the SIS trip input maintenance to avoid signal forcing. MOS shall be a hardwired enable key-switch for a particular unit which requires the synchronization between the panel operator and maintenance technician. The activation of MOS shall also be recorded by SCADA with clear lamp status on the operator panel.

A stand-alone panel with SIS pushbuttons, selectors etc. shall be included within the control room for MOS, OOS and selected trip/stop functions. Actual requirements to be determined during detail design.

SIS Architecture

The safety system network shall be certified by TUV linking individual safety system controllers. The safety network shall support common sequence of events recording (SER) network and Engineering workstations.

Reliability

The system shall be a fault tolerant microprocessor based design that protects the controlled process from intermittent, transient, and permanent system faults. Any single fault shall not degrade system safety or functionality or impact operation of the controlled process.

Any single fault must be repairable on line without interruption to the process.

Any fault occurring in the system must be alarmed with indication of exact location of the faulty component.

The system shall be designed so as to be unaffected by common mode failures.

Any fault resulting in a system failure shall be such that all failure modes are fail-safe to the OFF or OPEN State. This shall include all module removal and cable faults.
The system shall be designed for maximum reliability, safety, and integrity while maintaining availability that shall be 99.99% or better in both fail-safe and fail-danger modes. Availability figures and their definition must be provided as part of the design scope.

System Redundancy

There shall be no single failure point that could affect more than one channel. Failure of any single active component supplied within the system shall not cause a shutdown action, and during such a failure, the system shall remain on-line and shall maintain the process safety protection. Additionally, the system shall accommodate a means for alarming the fault.

The individual inputs for any point shall be brought into a terminal strip, which is independently powered from the other two points of the voting system. No one fuse or power failure is to affect the power or controls of the other voting components.

The design shall clearly explain the system’s actions and response upon the failure of one and more of its redundant channels. Diagnostics shall indicate each failure level and provide mechanisms for a user-initiated shutdown within each failure mode.

It shall be possible to replace and repair any faulty system module without degrading the safety of the system. Repair shall not require disruption of the scanning process or "freezing" of output states, the transition to the healthy module shall be bumpless (i.e. no

loss of control). No operator action shall be required to restore the system to normal operation other than simple mechanical replacement of modules.

Input and output signals shall be voted independently. Output signals shall be designed as de-energize to trip.

I/O General

The design will include the assignment of I/O (card and point layout).

Termination for field devices will be made to separate (marshaling) termination strips (grouped by voltage levels as well as type of signal - analog or discrete) in the SIS termination cabinet. Multi-conductor cables and connectors provided will be used for connection between the external termination panels (ETP's) and the I/O modules.
Field multi-pair cables will be terminated by the Project Installation Contractor.

Input Modules

Input connection details shall be designed for maximum reliability. As a minimum, where multiple sensors are used, a failure of one field input shall not disable any other input and repair must be possible without impacting other inputs or the process.

Output Modules

The design must include load resistors on unused/spare discrete output points or make alternative arrangements such that the system does not see these as faulted points.

The design shall include any dropping (precision) resistors necessary for analog modules operating with 4 to 20 mA DC.

Automatic Testing and Diagnostics

The system shall incorporate comprehensive self-diagnostics such that all permanent and transient faults related to I/O are identified, alarmed and reported. Diagnostics shall be capable of identifying, locating and reporting the following faults as a minimum:

- Range Alarms
- Pre-trip alarm
- Trip alarm
- Deviation/ discrepancy Alarm
- Power supply faults

The above-programmed diagnostics are additional to those system diagnostics provided by the Vendor system.

Process I/O or system related fault information shall be available and displayed on SCADA in a manner that clearly assists fault diagnosis down to an instrument or module level. All process I/O related alarms must be transferred to the SCADA over the redundant communication interface.

Details of any system or logic fault should be easily determinable from the SCADA Engineering Workstation.

The SIS shall incorporate comprehensive self-diagnostics such that all permanent and transient faults are identified, alarmed and reported. Diagnostics shall be capable of identifying, locating and reporting the following faults as a minimum:

- Scan failure of main or I/O processors
- Memory faults, both PROM and SRAM
- Microprocessor faults
- Communication faults
- I/O interface or addressing faults
- Application program and hardware layout consistency
- I/O module faults
- Voted signal discrepancy on inputs and outputs
- Voted discrepancy on calculated values within the application program
- Load power or fuse faults on field circuits
- Power supply faults including battery back-up monitoring and output voltage verification
- Over-temperature conditions

Expansion and Spares

Process control, SIS and F&G Systems shall be designed so that after commissioning the following evenly distributed spare capacity shall be available at each location:

- I/O Modules – 10% installed, wired and fully functional I/O of all types
- I/O Racks – 20% fully wired spare rack space (modules not installed)
- Terminal Blocks – 25% spare
- System Cabling – 25% spare pairs
- Fiber Optic (FO) – 100% spare fibers

Loading Criteria

The system shall be designed such that, after commissioning, the loading criteria of the following shall not exceed 70% including spare capacity and spare space:

- Processing capacity and/or memory
- Communication network
- Hard disc utilization

The system power supply units shall not exceed 75% loading (including spare capacity and rack space).

Expansion Requirements

The system shall be capable of expansion at a future date without major changes to device and network configuration. For guidance 50% increase shall be assumed for total I/O and total nodes on any SIS, F&G, Process Control, etc., Local Area Network (LAN) after plant start-up.

Operator Interface

The operator interface shall comprise a mosaic tile panel, located in the Central Control Room's desk.

SIS pushbuttons shall employ normally closed contacts in the plant healthy state (i.e., open to trip). Each pushbutton shall have logic driven illumination, indicating the state of the switch, and shall have a guard to prevent inadvertent operation. Logic reset push buttons shall be normally open contacts (i.e., close to reset the logic).

The illuminating push buttons shall be connected to a common lamp test system. Stand-alone panel with SIS pushbuttons, selectors etc. including MOS, OOS and selected trip/stop functions shall be provided within the CCR. Actual requirements to be determined during detail design.

Interfaces

SIS – Electrical Interface

The SIS system shall interface with electrical MCCs and switchgear, (main and tie breakers, starters, contactors, etc.), via discrete hardwired signals for tripping/isolation.

SIS – Package Equipment

The SIS system shall interface with package units via discrete hardwired signals for tripping/isolation. The SIS system shall provide volt free contacts for the initiation of package equipment SIS.

SIS – F&G

At each location the SIS to Fire and Gas panel interface shall be hard wired with the Fire/Gas signal normally-closed, open to initiate SIS action.

Inhibits and Overrides

SIS initiators and outputs shall be provided with "override" or "maintenance bypass" switches to allow fault-finding, field-testing and "start-up overrides" as defined on the SIS Cause and Effect Diagrams. Maintenance bypass switches shall be of the key-switch type, with lighted indicators on the System cabinet.

Actuation of inhibit mechanisms shall suppress automatic logic action from the related channel, but shall not suppress the alarm function to the SCADA. Actuation of override mechanisms shall only prevent the final related output from being tripped. All inhibits and overrides shall be logged and displayed on the System printer. Actuation of one or more individual override mechanisms shall cause a common alarm to occur at the SCADA. All inhibit and override switches shall have identical keys, which shall be retained in the key lock, while the override is active.

SIS EQUIPMENT REQUIREMENTS

2.1 The purpose of the SIS installation is to automatically prevent the occurrence of any physical situation, which could potentially cause loss, damage or undesirable effects on plant, equipment, product, raw material, property, people and the environment.

2.2 The SIS equipment installation shall be independent of other plant instruments and instrumentation systems, such that any faults and failures in SIS instruments and systems shall not cause a corresponding failure or fault in the integrity or operability of the SIS system. Unavoidable exceptions to this principle shall, if possible, cause the SIS system to operate and shut down the appropriate section of plant i.e., shall "fail safe".

2.3 Essentially the SIS/F&G System comprises the system hardware, firmware and software interlinked by robust communication networks. The System integrity will be such that reliability measures will be addressed to achieve at least 99.99% availability of the overall scheme.

The system shall be fault tolerant microprocessor based design that protects the controlled process from intermittent, transient, and permanent system faults. Any

single fault shall not degrade system safety or functionality or impact operation of the controlled process.

Any single fault must be repairable on line without interruption to the process.

Any fault occurring in the system must be alarmed with indication of exact location of the faulty component.

The system must be designed so as to be unaffected by common mode failures.

Any fault resulting in a system failure shall be such that all failure modes are fail-safe to the OFF or OPEN state. This shall include all module removal and cable faults.

- There shall be no single failure point that could affect more than one channel. Failure of any single active component supplied within the system shall not cause a shutdown action, and during such a failure, the system shall remain on-line and shall maintain the process safety protection. Additionally, the system shall accommodate a means for alarming the fault.
- The individual inputs of any point shall be brought into a terminal strip, which is independently powered from the other two points of the voting system. No one fuse or power failure is to affect the power or controls of the other voting components.
- The Vendor shall clearly explain the proposed system's actions and response upon the failure of one and more of its redundant channels. Diagnostics shall indicate each failure level and provide mechanisms for a user-initiated shutdown within each failure mode.
- It shall be possible to replace and repair any faulty system module without degrading the safety of the system. Repair shall not require disruption of the scanning process or "freezing" of output states, the transition to the healthy module shall be bumpless (i.e. no loss of control). No operator action shall be required to restore the system to normal operation other than simple mechanical replacement of modules.
- Input and output signals shall be voted independently. Output signals shall be designed as de-energized to trip.

2.4 The design principle for all SIS equipment shall be to "fail safe". The following are examples of this principle:-

- Air failure shall cause pneumatic SIS valves to move to the shutdown (safe) position (Note: Electrically operated SIS valves need to be fed from UPS).

- Electronic modules shall be self-checking and shall "fail safe" if a fault is detected.
- Initiating contacts shall be normally closed and shall open to shutdown.

2.5 The design and installation of every component and part of the SIS installation shall either enable it to be tested or its operability and integrity shall be subject to continuous monitoring during normal operation of the plant. Failure shall be fail-safe and shall alert the operator.

Test facilities shall wherever possible, not prevent or impair the operation of the SIS system, if this cannot be achieved a control room system alarm shall operate whenever an input or output is detected or bypassed, generally all the SIS system alarms shall remain operable during testing.

2.6 The design basis for the majority of electrical instruments in hazardous areas is explosion proof. Instruments shall be supplied with SMART capability to enable systems and maintenance diagnostic interrogation. It should be noted that SMART instruments adopted for SIS service shall have selected functions permanently disabled.

2.7 The system as a whole shall be certified by TUV to required SIL-3 classification, or by any other internationally recognized body subject to approval by the client. An abridged TUV test report of the system proposed shall be furnished by the supplier for acceptance by the Client. Failure to provide such a report shall render the proposed system unacceptable.

Instrument loops for the facility will be engineered to meet the target SIL derived from hazard assessments. Validation will be obtained for Safety Instrumented Systems adopting quantitative and qualitative methods detailed in ISA/84.

Hazard analysis studies will specify requirements for instrument integrity from SIL-0 through to SIL-3, the latter being the most onerous to achieve with regard to instrument engineering capability. It will be the project intention to assess the requirements so that the lowest SIL is achievable whilst adopting appropriate alternative methods of risk mitigation out-with instrumented loop function.

Essentially the Control System will contain SIL-0 assessed and validated loops, whilst the SIS System will contain all designated loops and validated greater than SIL-0. Some SIL-0 loops may be specified for SIS System connection if the loop requires for example, a high availability requirement.

SIS SYSTEM ELECTRONICS

General Requirements

3.1.1 The SIS system electronics includes the following hardware:-

(a) Centralized electronics package housed in a cabinet or cabinet suite.
(b) SIS system annunciation lamp box, for remote mounting on the operation consoles.
(c) SIS initiation and reset hand switch panel/matrix, for remote mounting on the operator consoles.
(d) Triple Modular redundant CPU as a minimum.

Note: - The multi-core cable cord sets with plug and socket connections for interconnecting (b) and (c) shall be included in the SIS supplier's scope of supply.

3.1.2 The SIS system electronics shall include the following primary functions:-

(a) The logical processing of input signals to operate output circuits.
(b) The lamp power and logic functions for a remote alarm annunciation lamp box.
(c) The communication by serial link of all system events to a sequence of events recording system (SER) (Part of the process control system).

3.1.3 The SIS system electronics package shall be designed and constructed from proven (at least 2 previous years satisfactory applications) standard modules and components.

3.1.4 The SIS active signal paths shall be duplicated and separate so that no single failure or fault shall prevent the system operating i.e., if a valid shutdown input signal occurs and one channel has failed the output shall de-energize and initiate a shutdown.

3.1.5 The electronics shall be supplied from an uninterruptible power supply source of 120V 60Hz, each channel shall have independent DC power supplies connected to this source.

3.1.6 Only signal paths which determine the safety reliability of the SIS system shall be duplicated e.g., annunciator circuits shall not be duplicated.

3.1.7 All overall plant SIS function shall be grouped together in the centralized electronics package, which shall be housed in a single or suite of cabinet/s. The cabinet shall be installed in a non-hazardous central control building.

3.1.8 The operation of SIS valves which require air or electric power to achieve their safe position shall be confirmed by a valve limit switch input to the SIS system logic. The shutdown alarm shall confirm valve operation i.e., MOVs, double acting piston actuators, etc.

3.1.9 SIS circuits shall remain in the tripped condition after operation; systems shall be reset electrically by momentary operation of remote reset switches. Reset switches may be located in the field or on the control room operators console as appropriate.

3.1.10 The SIS electronics shall be of rugged construction and designed to be maintained by personnel with a minimum of specialist training.

3.1.11 The SIS electronics shall be capable of providing a service in the event of heating and ventilation failure e.g., able to operate between –5 to 60°C and 0 to 99% (non condensing) relative humidity, unless otherwise specified.

The selection and arrangement of equipment within the cabinet shall ensure that the maximum temperature rise inside the cabinet does not exceed 10°C above ambient. Forced draught ventilation methods shall preferably not be used.

3.1.12 During transportation, installation and operation the equipment may be subjected to shock and vibration. The maximum levels of shock and vibration that the equipment is able to tolerate shall be stated by the Vendor.

3.1.13 The SIS electronics shall not be susceptible to, nor interfere with, hand held radio transceivers in the immediate vicinity or any other electronic equipment. The equipment shall be immune to signal strengths of 10V/m over the range of 100kHz to 1000kHz. This requirement shall apply with the SIS systems cabinet door open.

3.1.14 The system shall be maintainable without having to shutdown the plant.

3.1.15 There may be some 2 out of 3 voting systems, all critical inputs will have three field sensors input into the SIS. The system will then vote on all three of these inputs and all subsequent logic will be implemented using the voted result.

Whenever possible, the three inputs will be analog signals, to take advantage of an analog signals self-revealing mode of failure. All analog signals will be monitored for a self-diagnosed failure condition and configured to fail away from the shutdown setting. If this happen a deviation alarm would be generated indicating that one of the three transmitters is reading a value different from the others by greater than a pre-set amount. If more than one transmitter in a 2oo3 configuration fails then the logic shall vote for a trip condition. All field devices will be energized for normal conditions, de-energized for shutdown.

Scan rate and execution time for any input/output shall be 100ms.

The SCADA will scan the SIS every 4 seconds or less. Any alarm condition that occurs in the SIS must be retained long enough for the SCADA to see it, even if the condition only exists for a single scan time.

Any time a shutdown occurs, the system will provide a means of identifying the "first-out" condition that initiated the shutdown. This information will be made available to the operator immediately and clearly on the SCADA screen, so that the condition can be corrected and the system restarted as soon as possible.

It should not be assumed that maintenance personnel are available to troubleshoot the problem. The intent is to be able to preserve the "first-out" and sequence of events information and not have it overwritten by new information if another shutdown occurs.

An alarm should be initiated whenever there is a deviation between any voting field inputs monitoring a particular condition. For discrete devices, this is straightforward. For analog devices, the alarm should be set when deviation between any one point and either of the other two points is greater than a set amount. If a point continues to remain in a deviation condition then the associated deviation alarm must re-annunciate on a regular time period (TBA).

3.1.16 Generally all shutdowns will have pre-alarms from independent sources (other than that of the SIS equipment) that will annunciate on the SCADA and warn the operator that he is approaching a shutdown point.

Mechanical and Wiring Requirements

3.2.1 Cabinet shall be of sheet steel construction approximately 2100mm high x 1200mm wide x 800mm deep mounted on a 100mm high steel plinth. The cabinet shall be provided with removable lifting lugs. The front door shall have a transparent window providing an unimpeded view of all module LEDs and bypass switches.

The Vendor shall mount all equipment in standard Rittal/Hoffman cabinets suitable for a safe environment, with a minimum NEMA 4 certification. Cabinets shall be supplied with cooling fans for proper ventilation where required and come equipped with a window door.

Vendor shall provide an electrical outlet inside the cabinet for test equipment this shall be powered independently from the UPS.

The Vendor will supply external Termination Panels (ETP). All inter-panel wiring shall be terminated to the ETP's.

3.2.2 Cabinet shall be painted to vendor's standard specification in the following colors:-

- External Surfaces :As defined in the Material Requisition (MR)
- Internal Walls : White
- Plinth : Black

3.2.3 Cabinet shall be fitted with hinged doors at the front which shall be lift off and lockable. Equipment shall be mounted on swing frames for accessibility if the cabinet is restricted to front access only. All terminals and cable entries shall be easily accessible. Door pockets shall be provided for storage of drawings.

3.2.4 Incoming cables shall have ample space for bending and handling. Cable clamps and clamping rail to be included. Gland plates to be provided for armored cables. Removable gland plates shall be fitted in top or bottom of the cabinet to suit incoming cables.

3.2.5 Cabinet shall be delivered fully assembled and wired and include:-

(a) 19" rack mounted electronic equipment.
(b) Mains isolator and miniature circuit breakers.
(c) Wiring to the input/output terminals and power supply connections.
(d) Power supply units.
(e) Intrinsic safety barriers.
(f) All wiring shall be segregated/color coded according to type (input or output) and voltage levels and type (AC or DC).

3.2.6 Three separate ground connections shall be provided. (b) and (c) shall be insulated and isolated from (a) and each other.

(a) Safety ground (cabinet and all steelwork).
(b) Signal ground (cable screens and signal common).
(c) I.S. ground.

3.2.7 Terminals shall be provided for all spare cores and screens of incoming multi-core cables.

3.2.8 All terminals and barriers shall be mounted on clip on rails. Terminals shall be of the compression type. Intrinsically safe terminals shall be blue and shall be segregated from non I.S. terminals.

3.2.9 All terminals and barriers shall be labeled with the terminal identification, which shall also be shown on layout and connection drawings.

3.2.10 All terminals carrying voltages in excess of 50V shall be segregated, shrouded, and clearly marked with the voltage.

3.2.11 All wires connected to compression type terminals shall be fitted with crimped on wire pins.

3.2.12 All interconnecting wiring shall be identified with the number of the other end terminal to which it is connected by means of cable markers ('O' type). Input/output wiring identity markers shall include the terminal number of the field device to which it is connected. All cord sets and ribbon cables shall be identified with their connection points.

Jumpers shall be shunts on terminal strips or bus bars.

All fusing terminals shall be compression type.

All wires shall be stranded copper except for thermocouple where it should match the thermocouple type.

Wire sizes shall be selected to comply with current electrical design requirements.

3.2.13 Wiring shall not be carried over terminals or bent around sharp edges.

3.2.14 Discrete signal wiring shall be single core unless otherwise stated and shall be $0.75mm^2$ minimum size. Card bins shall be interconnected with plug and socket cord sets or ribbon cables and edge connectors.

3.2.15 Signal and power supply wiring shall be encased in black ducting or equivalent having removable clip-on lids and side slots for entry/exit of wiring. Intrinsically safe wiring shall be in blue trunking and kept segregated from all other wiring.

3.2.16 No ducting shall be more than 60% full when cabinet wiring is completed.

3.2.17 Wiring colors:

	Live	**Neutral**	**Jacket**	**Ground**
120V AC	Black	White	Black	Green / Yellow
120V DC	Black	White	Black	Green / Yellow
24V dc Control Logic	Red	White	Grey	

3.2.18 The design and size of the annunciation lamp box and switch panel for remote console mounting shall be carefully coordinated with the operator console Supplier, to enable them to be easily installed at site.

3.2.19 Annunciation lamp units shall have multiple bulbs, approx 2W total per window.

Transparent screens shall be engraved with the service description.

Red screens shall be used for trip annunciation.

Amber screens shall be used for bypass and fault indication.

3.2.20 Switch panel hand switches shall be of high quality, with a pair of contacts, one for each channel. They shall have an illuminated top and engraved screen, which shall be legible when unlit.

Reset switches shall have yellow screens and be illuminated when the system is reset and the plant is operating.

SIS manual initiation switches shall have a transparent hinged cover to prevent accidental operation, and a red screen which shall be illuminated when the SIS system operates (i.e., tripped).

3.2.21 All system and I/O modules shall be capable of operating at a minimum of +/-10% available voltage and +/-5% available frequency. The Vendor will be responsible for internal system power distribution and coordinated circuit protection. The Vendor’s design is subject to Contractor and Owner’s approval.

Separate 24 VDC redundant field interrogation voltage and final actuating element power supplies shall also be provided. The design shall include redundant 24 VDC converters for powering of field transmitters and discrete inputs and be responsible for designing the power distribution with protection for all system I/O. Failure alarms for each DC/DC converter are also to be provided. Contractor and Owner’s approval of field device power distribution is required.

Design shall include the power requirements for each cabinet and total power for each system to size the incoming line power requirements. Design will include inrush currents and crest factors.

The design shall state equipment safety and instrument grounding requirements.

Design shall include drawings and written instructions on primary power and grounding systems. Vendor shall review power and grounding drawings as required to verify proper design.

Any 24 VDC power supplies that may be used in the SIS cabinets to power field I/O shall be capable of accepting 120 VAC, +/-15% and 60 Hz at +/-5%.

Power supplies shall be dual redundant as a minimum, each capable of supplying complete system power. System shall accept power from two different power sources. Power supplies shall be replaceable on-line without disrupting the process and without impacting main processor triplication. The system must be designed to alarm if one of the power supplies in a redundant set fails.

Electronic System Requirements

3.3.1 All modules of the system shall include the fail-safe self-checking feature.

The self-checking system shall confirm that each component in the primary SIS signal path is healthy and will operate when required, detected faults shall cause the module to “fail safe” and operate an alarm to alert the operator.

3.3.2 Although all the plant SIS systems shall be contained in a single cabinet or suite, each of the sections of the system e.g., storage tanks and each channel of each section shall be installed in identifiable separate locations and not randomly intermixed throughout the racks.

Also the power supply arrangements for each section and channel shall be separately protected and identified.

3.3.3 All rack bin modules shall be arranged logically, for instance, bypass switch modules shall be adjacent to the input, output and logic modules served.

3.3.4 The front plate of all modules shall be equipped with comprehensive LED indications to enable all operating, diagnostic, test and fault conditions to be identified.

Bypass switch operation shall be indicated by LEDs, in addition to a common remote alarm per system. Input and output status shall be indicated by LEDs.

3.3.5 Multiple input, output or logic modules shall not be utilized for both channel 1 and 2 signal paths of a single system. It shall be possible to remove and replace a module without causing a shutdown.

3.3.6 Input circuits shall include an input filter to prevent spurious operation and protect against common mode and series mode induced voltages.

3.3.7 Where specified, input signals shall be provided with a 1-5 sec. ON or OFF time delay.

3.3.8 Logic modules shall be solid-state non-programmable, hardwired, such that the logic may be changed only by making physical wiring alterations or replacing a plug in pre-wired logic module.

3.3.9 Keylock bypass switches shall be provided for all SIS plant interface inputs and outputs, the switches shall be mounted adjacent to the associated input and output modules.

Input bypass switch operation shall only bypass the control function of the SIS, input alarms shall remain operable.

Output bypass switch operation shall typically de-energize the output circuit and enable proper operation of the shutdown element to be verified (e.g., valve closure or partial closure).

The operation of any system bypass switch shall initiate a self-cancelling, hardwired alarm on the operators console to warn the operator that a particular system is disabled.

The design principle for bypass switches shall be that their operation shall have a minimum disabling effect on the SIS system functions and the alarms should remain operable.

3.3.10 Where SIS functions will prevent startup of the process (e.g., low flow shutdown) the system reset circuit shall incorporate a timer which will operate a timed defeat of the appropriate input to enable the plant to be started. This defeat shall only be operable at start up.

3.3.11 Analog inputs to the system electronics may be from either 4-20mADC field transmitters or thermocouples.

It shall be possible to calibrate and adjust or check, the set point of any analog input from the front of the modules without removal from the rack.

3.3.12 The electronics system shall provide the lamp and audible driver circuits and the operating (including “first-up”) reset and test logic, for the remote console mounted annunciator lamps. The acknowledge, reset and lamp test pushbuttons will be located remotely from the lamp box.

3.3.13 The electronics system shall provide a dual redundant optically isolated serial (RS 232/RS 442) communications data link (protocol to be agreed) to the plant SCADA system. This data link shall provide the data to enable recording of all SIS system events with a maximum 10m sec discrimination.

Events to be recorded shall include:-

- Input and output status changes
- Electronics faults and failures
- Bypass switch operation
- Reset switch operation
- Channel discrepancy events

3.3.14 The SIS shall be provided with the necessary software logic for partial stroke testing of final control elements such as control/SIS valves. This will improve the reliability, availability and SIL requirements of the plant.

3.3.15 Alarm Signal Handling

The SIS shall have facilities to generate alarm output signals (serial and hard wired).

Each alarm is included in a UZ group, except for the system and utility alarms.

Each UZ group shall form a first failure alarm group in which the first trip alarm that comes up is recognizable. For local panels, all alarms shall be assigned to two first-up groups, one for the local panel itself and the other for the signals to the SCADA.

The first failure resets for these two groups shall be by means of a button on the local panel and a signal from the SCADA, respectively.

The first failure alarm coming up in a UZ group shall be transmitted as such to the SCADA or, in the case of local panels, shall cause the lamp to flash at twice the frequency of subsequent alarms. UZs tagged ‘misc’ (miscellaneous) do not require the first failure feature.

For alarms presented to the SCADA, the SCADA shall take care of the sequence upon receipt of the alarm and the first failure indication. First failure reset signals shall be provided by the SCADA.

For local panels and F&G mimic panels, the alarm sequence shall be in accordance with ISA S18.1 M (alarm only with lock-in facilities) and ISA S18.1 F (first failure or first-up alarm groups). The acknowledge, first up reset and lamp test shall be hard wired voltage free contact inputs from the local panel.

The acknowledge, first-up reset, lamp test and audible alarms (per UZ group) need not be reflected on the functional logic diagrams provided.

SIS common utility and common system alarms shall cover such conditions as (partial) power supply failures, abnormal temperature conditions within cabinets, CPU failure, module failures and ground faults. These alarms shall be logged by

the SER. For each SIS cabinet, at least one common utility alarm and one common system alarm shall be transmitted to the SCADA.

Inputs/Outputs

Inputs

The action of input devices is as follows:-

(a) Process field switch contacts are closed when plant conditions are safe and open when there is a fault. On the logic diagrams these contacts shall be shown in the position which corresponds to power off and no process signal present (i.e., "on the shelf" condition).
(b) Valve limit switch contacts close when the valve reaches the end of its travel, in either direction.
(c) Motor running contacts are closed when the motor is running.
(d) Hand switches for "Trip" and "Stop" have normally closed contacts which open when the button is pressed and close again when it is released.

Inputs to the logic system will be as follows: - (switches are "volt free").

(a) from field switches (hand and process) in hazardous plant areas.
(b) from field switches (hand, process and motor control center) in safe plant areas.
(c) from hand switches on the console in the Control Room (safe area).
(d) from 4-20mA field transmitters.
(e) from thermocouples (mV inputs).
(f) from bypass and test switches logic cabinet.

Outputs

The action of output devices is as follows:-

(a) Solenoids are normally energized when plant conditions are healthy and de-energized under fault conditions. This is a fail-safe mode since loss of power will have the same effect as a trip signal.
(b) Motor start relays are normally de-energized. If the relay is operated for about 0.5 sec the motor starts and then continues to run when the relay is released.

(c) Motor stop relays are normally energized. If the relay is released the motor stops and remains stopped when the relay is operated again.

(d) Outputs to annunciator lamps are normally de-energized when conditions are healthy.

(e) Volt free contact outputs shall be closed when plant conditions are healthy and open to shutdown/trip.

Outputs from the logic system will be as follows:-

(a) Power to solenoid coils in field: 120V DC, 20W.

(b) Power to relay coils in interposing relay panel for motor start/stop: 24V DC, 5W (safe area).

(c) Power to audible alarm in Control Room: 24V DC.

(d) Power to alarm annunciator lamps in Control Room: 24V DC, 2W.

(e) Volt free contacts to foreign systems: Max 120V 60Hz, 2A, min 24V DC 1A.

SUPPLIER RESPONSIBILITIES

4.1 The supplier shall be responsible for the design of the system in compliance with the specification, based upon the functional information provided by the Contractor.

4.2 The supplier shall undertake to maintain spares or direct replacements for the supplied equipment 10 years after the time of declared obsolescence.

4.3 Supplier shall provide a maintenance proposal with a guaranteed response time for breakdown calls.

4.4 Supplier shall confirm availability of training for engineers and technicians responsible for operating and maintaining the equipment.

4.5 The supplier shall demonstrate previous successful communication interface with the SCADA system.

4.6 The supplier shall provide a system reliability and availability analysis calculation for the system to include sub-system components using a recognized methodology and internationally accepted component reliability figures. The supplier shall endeavor to provide availability figure of 99.99% defined as MTBF (MTBF + MTTR).

The calculation shall be based on an appropriate proof testing frequency e.g. proof testing shall be typically carried out every three months where there is a low probability of a potentially hazardous event occurring i.e., less than once a year.

4.7 The supplier's scope of supply shall be specified on the Contractor's data sheets, options in this specification shall comply with the specific requirements stated in the data sheets.

SYSTEM TESTING

General

The supplier shall perform a full program of inspection and testing in accordance with a comprehensive procedure, which shall be approved prior to implementation. All equipment shall be inspected and tested by the supplier prior to inspection by the Contractor, or his representative.

All system tests shall include the cabinet, remote annunciation lamp box and remote switch panel interconnected with the system cord sets.

The supplier shall at the end of the manufacturing phase, perform his own inspection to ensure each system is fully operational and complete in all respects. All temporary facilities for the test program shall be supplied and connected by the supplier. All temporary work shall be of a good and safe engineering standard.

Supplier's Test Equipment

The supplier shall supply all calibration, testing and simulation instruments required to perform the testing to a standard approved by Contractor.

All test equipment provided by the supplier shall be covered by up to date test certificates.

The test equipment supplied shall include but not be limited to the following: -

Specialized test equipment for testing individual cards or components.

Interconnecting cables for connection of all test equipment including jack sockets, plugs, etc.

Simulator (if required) to simulate the final on-site configuration. This unit shall be suitable for the system functional testing and shall generally comprise lamps, switches and 4-20mA signal simulators.

Inspection and Testing Documentation

The supplier shall produce a comprehensive test procedure and prepare a manual of test record sheets for use during works testing and for onsite pre-commissioning test.

The manual of test record sheets shall be of such a format as to allow system test personnel to work through the tests required and to record all the results as the tests proceed, including all failures and subsequent retesting. Any printouts forming part of the tests shall be included in the manual. This manual shall be maintained through all stages of testing on the equipment.

Prior to commencement of any factory or site testing, all required test procedures, record manuals and documentation requirements shall be available in a fully updated format at the appropriate test venue.

Stages of Testing

The hardware and software to be supplied shall be tested in the following stages: -

- Hardware Tests
- Electrical Tests
- Heat Soak Tests
- Factory Acceptance Tests (functional) (FAT)
- Site Tests (SAT)

Hardware Tests

The following hardware tests shall be completed by the supplier prior to witness factory tests. A detailed test program shall be developed. Supplier to test and confirm that all equipment within the system complies with the design requirements.
The Supplier shall provide all test equipment as required by the test program for the duration of the test. The tests shall include the following equipment as a minimum.

(a) input modules
(b) output modules
(c) logic modules
(d) general electrical installation
(e) bypass and test facilities
(f) switch inputs and lamp outputs
(g) event recording facilities and communications data link
(h) system fault alarm facilities

Electrical Tests

Appropriate electrical systems shall be tested for insulation resistance, correct polarity and continuity. To prevent damage, low voltage equipment operating at "signal" voltage levels shall be disconnected as necessary and reconnected prior to functional tests of the system.

Grounding shall be tested for faults and continuity.

All terminations, glands, junction boxes and other electrical equipment enclosures shall be inspected for correct application assembly and closure.
The equipment shall also be checked to demonstrate the following: -

Power supply tests over stated limits (by Contractor).

Rejection of series and common mode noise on input signals.

Immunity to mechanical vibration (Vendor to advise maximum levels of shock and vibration which the equipment is able to tolerate).

Immunity to RF interference (immune to signal strengths of 10V/m over the range 100kHz to 1000MHz).

The above tests shall be repeated at the Factory Acceptance Test (FAT).

The Vendor shall rectify and retest satisfactorily at his cost any faults found during the tests before undertaking the Factory Tests (FAT).

Independent Testing

Where vendor does not have the facilities for mechanical vibration testing or RF interference testing it will be acceptable if satisfactory "type test" results for the equipment from a recognized independent testing body can be shown.

Heat Soak Tests

The system shall be operated by the supplier in its final onsite configuration with external interfaces simulated by supplier equipment, for a minimum period of 48 hours. All inputs and outputs shall be simulated for this period.

The system environment shall be subjected to an elevated temperature of 60°C for the 48 hour period with a temperature cycle of between 10°C and 60°C for a minimum of 10 cycles.

During the Heat Soak Test, the system equipment shall be fully exercised on a frequent basis. Fully loaded operating conditions shall be simulated at 12 hour intervals by exercising the logic via the simulated inputs.

Any part of the system failing during the Heat Soak Test shall be immediately replaced by the supplier at his expense, or fault rectified. The Heat Soak Test shall restart as soon as the fault has been rectified. Time taken to affect the repair shall not be included in the test. All faults shall be adequately recorded in the test record.

Acceptance Tests

Before the equipment can be delivered to site, satisfactory performance of the whole system, simulating all inputs, outputs and foreign device communications and functionality must be demonstrated to the satisfaction of the Contractor or their representative.

The Contractor shall prepare and submit detailed procedures and test sheets that shall cover the factory acceptance testing (FAT), system integration testing (IFAT) and site acceptance testing (SAT).

Factory Acceptance Test (FAT)

The full requirements of the test shall be defined in the "Factory Acceptance Procedure". Prior to advising the Purchaser that the equipment is ready for the factory acceptance test (FAT), the Vendor shall have completed its own internal full functional tests. These tests shall include the full systems and shall include a full 100% in-house test of the total I/O including all the software modules.

After this test, the Vendor shall submit the internal test report to the Contractor. The full FAT shall be witnessed by the Contractor and Client's representative.

On successful completion, the Vendor and Sub-Vendors shall undertake the integrated system test (IFAT).

Integrated Acceptance Testing (IFAT)

The full requirements of the test shall be defined in the "Integrated Factory Acceptance Procedure". In addition to the Vendor completing his own interface functional test, full equipment interface/integrated test with SCADA shall be carried out using the SIS system's processors. Integration testing shall cover the I/O simulation of SIS system all the way to SCADA HMI, SOE and history database. SIS Vendor shall be present while these tests are in progress until successful completion. The full IFAT shall be witnessed by the Contractor and Client's representatives.

Site Acceptance Testing (SAT)

The full requirements of the test shall be defined in the "Site Acceptance Test Procedure". These tests shall prove that the various systems have not been damaged during transit, that they are installed correctly and they function in accordance with the project design specifications requirements.

Fully integrated tests shall be performed including all sub-Vendors equipment and systems.

General

Before the equipment/systems can be delivered to site, satisfactory performance of the whole systems, simulating all inputs, outputs and Sub-Vendor device communications shall be demonstrated to the satisfaction of the Purchaser/ Client or their representative.
The Purchaser/ Client shall witness the above factory acceptance tests prior to releasing the equipment for shipment. The Vendor shall be responsible for conducting the tests and providing all necessary facilities, equipment and personnel.

Equipment required for test: -

(a) Supplier's simulation and test equipment as specified in 5.2.
(b) All hardware subsystems and components of the final design configuration.
(c) Sequence of events recorder communications receiver.

The system shall be fully operable and fully tested to the satisfaction of the supplier.

The tests to be carried out by the supplier prior to the Factory Test shall include a total system test, as detailed in Section 5.4.5.7, verifying all inputs and outputs for correct operation on both channels of the system, the operation of bypass switches, and the operation of external alarms and external communications interface.

System Tests

The system tests shall be carried out on the complete system. The following headings are recommended as minimum requirement and shall be developed in detail during implementation of the test procedures.

(1) Inspection of equipment

(2) Shock/Vibration Test

(3) Power Supply Variations

(4) Radio Interference Test

(5) Functional Test including: -

- (a) Operator Control Panel functions
- (b) Printed Circuit Board change over
- (c) Operation of Dual channels
- (d) Operation and Dual Communication channels
- (e) Operation of Power Supplies
- (f) Failure and interaction between systems
- (g) Systems Diagnostic Tests, including Self-test facilities
- (h) System functional and fault alarms

APPENDIX C – EPC CONTRACT

Draft: October 4, 2013

YUKON ENERGY CORPORATION

ENGINEERING, PROCUREMENT AND CONSTRUCTION CONTRACT

Draft: October 4, 2013

TABLE OF CONTENTS

PART 1 INTERPRETATION ..... - 1 -

1.1 Definitions ..... - 1 -
1.2 Interpretation ..... - 5 -
1.3 Schedules ..... - 6 -
1.4 Order of Priority ..... - 6 -

PART 2 TERM ..... - 7 -

2.1 Term ..... - 7 -

PART 3 THE WORK ..... - 7 -

3.1 The Work ..... - 7 -
3.2 Compliances ..... - 7 -
3.3 Inconsistencies ..... - 8 -
3.4 Schedule ..... - 8 -

PART 4 ENGINEERING ..... - 8 -

4.1 Design Responsibility ..... - 8 -
4.2 Investigation ..... - 9 -
4.3 Design Schedule ..... - 9 -
4.4 Design Review ..... - 9 -
4.5 Errors in Design ..... - 10 -

PART 5 CONSTRUCTION ..... - 10 -

5.1 Construction ..... - 10 -
5.2 Completion ..... - 10 -
5.3 Environmental Compliance ..... - 18 -
5.4 CEMP ..... - 18 -
5.5 Health and Safety ..... - 18 -
5.6 Principal Contractor ..... - 18 -
5.7 Approvals and Permits ..... - 19 -
5.8 Contractor's Documents ..... - 19 -
5.9 Format of Documents ..... - 19 -
5.10 Ownership of Documents ..... - 19 -
5.11 Use of Documents by YEC ..... - 19 -
5.12 Supervision ..... - 20 -
5.13 Investigations and Contraventions ..... - 20 -
5.14 Equipment ..... - 20 -

PART 6 SUSPENSION AND CHANGES ..... - 20 -

6.1 Suspension ..... - 20 -
6.2 Completion Date Adjustment ..... - 21 -
6.3 Changes to the Work Required by YEC ..... - 21 -
6.4 Changes to the Work Requested by the Contractor ..... - 21 -

PART 7 STATUS OF CONTRACTOR AND RELATED OBLIGATIONS ..... - 22 -

7.1 Independent Contractor ..... - 22 -
7.2 Contractor's Representative ..... - 22 -
7.3 Contractor's Superintendent ..... - 22 -
7.4 Contractor's Expenses ..... - 22 -
7.5 Liens ..... - 22 -
7.6 GST ..... - 23 -
7.7 Employees ..... - 23 -
7.8 Project Meetings ..... - 23 -

PART 8 WARRANTY ..... - 23 -

8.1 Warranty for the Work ..... - 23 -
8.2 Further Warranty Provisions ..... - 24 -

PART 9 YEC OBLIGATIONS ..... - 24 -

9.1 Provision of Documents ..... - 24 -
9.2 Information ..... - 25 -
9.3 Project Manager ..... - 25 -
9.4 Approvals and Permits ..... - 25 -
9.5 Inspection ..... - 25 -
9.6 Measurement ..... - 25 -
9.7 Non-Conforming / Defective Work ..... - 25 -

PART 10 PRICE AND PAYMENT ..... - 26 -

10.1 Price ..... - 26 -
10.2 Payment ..... - 26 -

PART 11 HOLDBACK AND BONDS ..... - 27 -

11.1 Setoff and Holdback ..... - 27 -
11.2 Bonds ..... - 27 -

PART 12 FOREST FIRES ..... - 28 -

12.1 Obligations of the Contractor ..... - 28 -
12.2 Prevention ..... - 28 -
12.3 Control ..... - 28 -

12.4 Reporting ..... - 28 -
12.5 Closure ..... - 28 -
12.6 Equipment ..... - 28 -
12.7 Claims ..... - 29 -
12.8 Requirements ..... - 29 -
12.9 Indemnity for YEC Costs ..... - 29 -

PART 13 IMPROVEMENTS ..... - 29 -

13.1 Improvements ..... - 29 -

PART 14 INDEMNITY ..... - 29 -

14.1 Indemnity ..... - 29 -

PART 15 INSURANCE ..... - 30 -

15.1 YEC's Insurance ..... - 30 -
15.2 Contractor's Insurance ..... - 31 -
15.3 General Insurance Provisions ..... - 32 -

PART 16 REPRESENTATIONS AND RELEASE ..... - 33 -

16.1 No Representations by YEC ..... - 33 -
16.2 Representations of the Contractor ..... - 34 -
16.3 Release ..... - 34 -
16.4 Responsibility for the Work ..... - 34 -

PART 17 FORCE MAJEURE ..... - 34 -

17.1 Force Majeure ..... - 34 -
17.2 Notice of Force Majeure ..... - 35 -

PART 18 DEFAULT, INSOLVENCY AND TERMINATION ..... - 35 -

18.1 Default ..... - 35 -
18.2 Insolvency ..... - 35 -
18.3 Remedies ..... - 36 -
18.4 Right of Termination by YEC ..... - 36 -
18.5 Effect of Termination ..... - 36 -
18.6 Contractor Equipment Removal ..... - 37 -
18.7 Extra Forces ..... - 37 -
18.8 Price Adjustment ..... - 37 -

PART 19 DISPUTE RESOLUTION ..... - 37 -

19.1 Amicable Negotiation ..... - 37 -
19.2 Reference to Executives ..... - 37 -

19.3 Arbitration ..... - 38 -
19.4 Consolidation of Arbitration ..... - 38 -
19.5 Expedited Arbitration ..... - 38 -
19.6 Continued Performance ..... - 38 -
19.7 Confidentiality ..... - 38 -

PART 20 ASSIGNMENT AND SUBCONTRACTING ..... - 38 -

20.1 Assignment ..... - 38 -
20.2 Subcontracting ..... - 39 -
20.3 Binding on Permitted Subcontractors ..... - 39 -
20.4 Copy of Subcontract ..... - 39 -

PART 21 CONFIDENTIALITY ..... - 40 -

21.1 Confidentiality ..... - 40 -
21.2 Exceptions ..... - 40 -
21.3 Survival ..... - 41 -
21.4 Injunctive Relief ..... - 41 -

PART 22 NOTICE ..... - 41 -

22.1 Notices ..... - 41 -
22.2 Receipt of Notice ..... - 42 -

PART 23 GENERAL ..... - 42 -

23.1 Amendment ..... - 42 -
23.2 Governing Law ..... - 42 -
23.3 Submission to Jurisdiction ..... - 42 -
23.4 Invalidity ..... - 43 -
23.5 Entire Agreement ..... - 43 -
23.6 Further Assurances ..... - 43 -
23.7 Enurement ..... - 43 -
23.8 Waiver ..... - 43 -
23.9 Time of the Essence ..... - 43 -
23.10 Execution ..... - 44 -

SCHEDULE A TECHNICAL SPECIFICATIONS..... - 45 -

SCHEDULE B TABLE OF CONTENTS FOR CEMP, AND ENVIRONMENTAL REFERENCE DOCUMENTS..... - 46 -

SCHEDULE C PROJECT SCHEDULE SUMMARY..... - 49 -

SCHEDULE D NOT USED..... - 50 -

SCHEDULE E INTERFACE POINTS AND RESPONSIBILITY MATRIX..... - 51 -

SCHEDULE F NOT USED..... - 56 -

SCHEDULE G SPARE PARTS; CONTRACTOR SCOPE OF SUPPLY..... - 57 -

SCHEDULE H PAYMENT SCHEDULE..... - 59 -

SCHEDULE I LIQUIDATED DAMAGES..... - 60 -

SCHEDULE J PERFORMANCE GUARANTEES..... - 61 -

SCHEDULE K COMPLETION TEST GUIDELINES..... - 63 -

SCHEDULE L DOCUMENTS FOR REVIEW..... - 66 -

SCHEDULE M JOB BOOK SPECIFICATIONS..... - 68 -

SCHEDULE N START-UP AND COMMISSIONING RESPONSIBILITIES..... - 70 -

SCHEDULE O NOT USED..... - 77 -

SCHEDULE P LIST OF KEY PERSONNEL..... - 78 -

SCHEDULE Q MECHANICAL COMPLETION REQUIREMENTS..... - 79 -

Draft: October 4, 2013

This Agreement is dated for reference the ____ day of , 2013.

Between:

> **YUKON ENERGY CORPORATION**, a Yukon Territory corporation, having an office at #2 Miles Canyon Road, Whitehorse, Yukon Territory, Y1A 6S7
>
> ("**YEC**")

and:

> **CONTRACTOR**
>
> ("**Contractor**")

Background

YEC is an electrical utility company in the business of generating and transmitting electricity in the Yukon Territory.

YEC is undertaking the construction of the Project.

The Contractor is in the business of designing and construction LNG storage, vaporization and sendout facilities.

YEC wishes to retain the Contractor to perform the Work for the design and construction of the LNG storage and sendout Project associated with the new power plant at Whitehorse, Yukon.

Agreements

The Parties agree:

PART 1
INTERPRETATION

1.1 Definitions

In this Agreement:

(a) **"Agreement"** means this engineering, procurement and construction contract, including any amendments to this Agreement, and all Schedules attached to this Agreement;

(b) **"Business Day"** means any day other than a Saturday, Sunday or a statutory holiday in the Yukon Territory;

(c) "**Change to the Work**" means an addition to, deletion from, or change to the Work made in accordance with Section 6.3 or 6.4;

(d) "**Completion Date**" has the meaning in Section 5.2;

(e) **"Completion Tests"** means the tests set out in Schedule K;

(f) "**Confidential Information**" has the meaning in Section 21.1;

(g) "**Construction**" means all things necessary to complete the Work, other than the Design;

(h) **"Construction Environmental Management/Work Plan (CEMP)"** means the plan to be delivered by the Contractor under Section 5.4;

(i) **"Contractor's Representative"** means the person appointed by the Contractor under Section 7.2 to administer this Agreement on behalf of the Contractor;

(j) **"Delay Liquidated Damages"** means the liquidated damages payable by the Contractor pursuant to Section 5.2(b)(x) and Schedule I;

(k) "**Design**" means everything necessary for the design and engineering of the Work;

(l) **"Design Basis"** means the design basis set out in Part 2 of Schedule A'

(m) "**Design Data**" means all calculations, drawings, designs, plans, specifications and other material produced by the Contractor to define the Work, or a portion of the Work;

(n) "**Design Schedule**" means the schedule provided by the Contractor to YEC pursuant to Section 4.3;

(o) **"Dispute Notice"** has the meaning in Section 19.1;

(p) **"Effective Date"** means the date first written above;

(q) **"Employees"** means those directors, officers, employees, agents or contractors of the Contractor utilized to perform the Work;

(r) **"EMS"** means Appendix C.4 of YEC's Environmental Management System Manual attached as Schedule B;

(s) "**End Date**" means the date by which Final Completion must be achieved and is identified on the schedule set forth in Schedule C;

(t) **"Environmental Protection Plan"** means the plan developed by YEC to consolidate the requirements for the protection of the environment related to the Project, as amended from time to time;

(u) **"Equipment"** means the equipment to be procured by the Contractor and used in the LNG Facility, as more particularly described in Schedule A;

(v) **"Expected LNG Date"** means the date that the Contractor expects YEC to begin delivery of LNG prior to Substantial Completion, which shall not be earlier than the date set out in Section 5.2(e) unless YEC has agreed to an earlier date;

(w) **"Facility Reliability Test"** has the meaning in Schedule K;

(x) **"Final Completion"** has the meaning in Section 5.2(c);

(y) "Final Completion Certificate" has the meaning in Section 5.2(c);

(z) **"Force Majeure"** means an event beyond the control of a Party under Section 17.1;

(aa) "**Guaranteed Completion Date**" has the meaning in Section 5.2(b)(ix);

(bb) "**Good Engineering Practice**" means using standards, practices, methods and procedures to a good commercial standard, conforming to law and exercising that degree of skill and care, diligence, prudence and foresight which would reasonably and ordinarily be expected from a qualified, skilled and experienced person engaged in a similar type of undertaking under the same or similar circumstances;

(cc) **"Holdback"** means the holdback monies owing by YEC to the Contractor under Section 11.1(e);

(dd) **"Job Book"** means the engineering, design, purchasing and contractor supplied information relative to the project as set out in Schedule M;

(ee) **"Lands"** means the lands on which the Work will be undertaken;

(ff) **"Laws"** means:

(i) all federal, territorial, regional and municipal laws, by-laws, rules and regulations;

(ii) any binding requirement of any Regulatory Authority; and

(iii) any judgment of a relevant court of law, board, arbitrator or administrative agency which is a binding precedent in the Yukon,

in each case, in force in the Yukon, or otherwise binding on YEC, the Contractor or any Subcontractor.

(gg) **"LNG"** means liquefied natural gas;

(hh) **"LNG Facility"** means the LNG trailer unloading facilities, LNG storage facility, regasification facility, and ancillary facilities, as further described in the Specifications, to be designed and constructed pursuant to this Agreement;

(ii) **"Mechanical Completion"** has the meaning in section 1.2(a) of Schedule Q;

(jj) "**Mechanical Completion Certificate**" has the meaning in Section 5.2(a)(i);

(kk) **"O&M Manuals"** means the operating and maintenance manuals to be delivered by the Contractor as part of the Work;

(ll) **"Parties"** means YEC and the Contractor and their respective successors or permitted assigns, and **"Party"** means either one of them;

(mm) **"Performance Guarantees"** means the performance guarantees set out in Schedule J;

(nn) **"Person"** means an individual, firm, partnership, body corporate, or other legal entity, a government or any department or agency thereof, a trustee, any unincorporated organization, and the heirs, executors, administrators, or other legal representatives of an individual, as the case may be;

(oo) **"Price"** has the meaning in Section 10.1;

(pp) **"Priority A Items"** has the meaning in Section 5.2(a)(iv)A;

(qq) **"Priority B Items"** has the meaning in Section 5.2(a)(iv)B;

(rr) **"Project"** means the construction of the LNG Facility associated with the new power plant at Whitehorse, Yukon;

(ss) **"Project Manager"** means the project manager identified by YEC to the Contractor under Section 9.3;

(tt) **"Punch List"** has the meaning in Section 5.2(a)(iv);

(uu) **"Punch List Items"** has the meaning in Section 5.2(a)(iv)B;

(vv) **"Regulatory Authority"** means an agency of the government of the Yukon or Canada who has authority pursuant to an enactment of the Yukon or Canada to regulate or control any aspect of the Work;

(ww) **"Spare Parts"** means the spare parts to be procured by the Contractor on behalf of YEC pursuant to Schedule G;

(xx) **"Specifications"** means the technical specifications for the Work to be performed by the Contractor, as set out in Schedule A;

(yy) **"Start-up Notice"** has the meaning in Section 5.2(f)(iii);

(zz) **"Start-up Period"** has the meaning in Section 5.2(f)(i);

(aaa) **"Subcontractor"** means any person having an agreement with the Contractor for any part of the Work including, but without limitation, the provision of services, materials or equipment, and **"Subcontract"** has a corresponding meaning;

(bbb) **"Substantial Completion"** has the meaning in Section 5.2(b);

(ccc) "Substantial Completion Certificate" has the meaning in Section 5.2(b);

(ddd) **"System"** has the meaning in Section 5.2(a)(i);

(eee) "System Punch List" has the meaning in Section 5.2(a)(iii);

(fff) **"Term"** means the duration of this Agreement under Section 2.1;

(ggg) "**Warranty Period**" has the meaning given in Section 8.1(b);

(hhh) **"Work"** means the design, construction, commissioning and start-up of the LNG Facility associated with the new power plant at Whitehorse, Yukon, to be performed by the Contractor under this Agreement, as described in the Specifications; and

(iii) "**Work Schedule**" means the schedule for performance of the Work provided by the Contractor to YEC pursuant to Section 3.4.

1.2 Interpretation

For all purposes of this Agreement, unless the context otherwise requires:

(a) words importing the masculine gender include the feminine and neuter genders, corporations, partnerships and other persons, and words in the singular include the plural, and vice versa, wherever the context requires;

(b) all references to designated Parts and Sections are to the designated Parts and Sections of this Agreement;

(c) using separate Parts and Sections, providing a table of contents, and inserting headings are for convenient reference only and will not affect how this Agreement is interpreted;

(d) any reference to a currency is a reference to Canadian dollars;

(e) except where otherwise specified, any reference to a statute includes a reference to such statute and to its regulations, with all amendments in force from time to time, and to any statute or regulation that may be passed which has the effect of supplementing or superseding the statute or regulation; and

(f) any reference to a Person includes a reference to any Person that is a successor to that Person.

1.3 Schedules

The following Schedules are attached to and form part of this Agreement:

Schedule A - Technical Specifications
Schedule B - Construction Environmental Management/Work Plan (CEMP)
Schedule C - Project Schedule Summary
Schedule D - not used
Schedule E - Interface points and responsibility matrix
Schedule F - not used
Schedule G – Spare Parts
Schedule H - Payment Schedule
Schedule I - Liquidated Damages
Schedule J - Performance Guarantees
Schedule K - Completion Test Guidelines
Schedule L - Documents for Review
Schedule M - Job Book Specifications
Schedule N - Start-up and Commissioning Responsibilities
Schedule O - not used
Schedule P - List of Key Personnel
Schedule Q - Mechanical Completion Requirements

1.4 Order of Priority

(a) If there is a conflict in this Agreement, the order of precedence of documents, from highest to lowest, shall be:

(i) the Agreement, excluding the Schedules;

(ii) Changes to the Work;

(iii) Schedule A - Technical Specifications;

(iv) Schedule H - Payment Schedule;

(v) all other Schedules.

(b) The following shall in all instances apply:

(i) for documents revised by either party and approved by YEC, the latest revision shall govern;

(ii) figured dimensions on drawings shall govern, even though they may differ from scaled dimensions;

(iii) drawings of larger scale shall govern over those of smaller scale of the same date; and

(iv) specifications shall govern over drawings regardless of time.

PART 2
TERM

2.1 Term

The term of this Agreement (the "**Term**") will commence on the Effective Date and, subject to earlier termination under this Agreement, will continue until completion of the Work to the satisfaction of the Project Manager, as confirmed in writing by the Project Manager.

PART 3
THE WORK

3.1 The Work

The Contractor shall, on a fixed-price turnkey basis:

(a) design, engineer and construct the Work;

(b) procure all Equipment, labour, tools and materials necessary for the Work;

(c) perform all obligations set out in this Agreement; and

(d) perform all related activities for the successful completion of the Work and the delivery of the LNG Facility in accordance with this Agreement.

3.2 Compliances

The Contractor will perform the Work, and will ensure that its Subcontractors, agents and Employees perform the Work, in accordance with:

(a) the Specifications;

(b) the terms of applicable permits and licenses relevant to the Work as issued by a Regulatory Authority;

(c) all lawful directions, guidelines, and other requirements of any Regulatory Authorities;

(d) all lawful directions of YEC;

(e) all Laws; and

(f) those parts of the EMS relevant to the Work, except to the extent that the EMS is inconsistent with the requirements of Section 3.2(a) to 3.2(e).

3.3 Inconsistencies

Each of the parties shall promptly and fully inform each other of any errors, omissions or inconsistencies in this Agreement, defects or Deficiencies in the Work and of any inconsistencies between this Agreement and any Law, of which they become aware. The Contractor shall exercise reasonable care and diligence to prevent any actions or conditions which could result in any such inconsistencies, defect or deficiencies. If the Contractor discovers any inconsistencies in this Agreement, or between this Agreement and any Law, or discovers any defects or deficiencies in the Work, it shall resolve all such inconsistencies with YEC before proceeding with the affected portion of the Work. If the Contractor discovers any inconsistencies in this Agreement, or between this Agreement and any Law, or discovers any defects or deficiencies in the Work, and proceeds without resolution with YEC, the Contractor shall proceed at the Contractor's own risk and expense and waives all rights to claim against YEC for the same.

3.4 Schedule

Within ten Business Days of the Effective Date, the Contractor will provide to YEC:

(a) a detailed Work Schedule;

(b) a schedule of dates for delivery of the submittals set out in Schedule L, which shall be consistent with any specific requirements of this Agreement; and

(c) a detailed schedule for planned site safety meetings.

The Contractor will issue revised schedules on a bi-weekly basis thereafter.

PART 4
ENGINEERING

4.1 Design Responsibility

(a) The Contractor shall ensure that the Design is performed by, or under the supervision of, the design personnel specified in Schedule P and shall not change any such personnel without the prior written approval of YEC.

(b) The Contractor shall control the Design and shall be responsible for the means, methods, techniques, sequences, and procedures necessary to complete the Design.

(c) The Contractor shall ensure that all portions of the Design are prepared under the direction of, and where appropriate by, engineers who are professional engineers or other such professionals as appropriate to the nature of the Design, lawfully authorized to practice within the Yukon. Such persons shall be available to meet with the Project Manager and YEC at all reasonable times during the Term and the Warranty Period.

(d) All final plans, specifications, reports or documents of a professional nature shall be signed by and stamped or sealed with the stamp or seal of the professional who prepared them or under whose direction they were prepared

(e) The Contractor shall undertake the Design using the standard of care, skill and diligence normally provided by a professional engineer in performing equivalent services and using Good Engineering Practice.

(f) Review and concurrence of the Work by YEC does not diminish the Contractor's responsibility for ensuring that the Work is fit and suitable for the intended purpose of the Project, as anticipated by this Agreement.

4.2 Investigation

The Contractor is solely responsible for the Design. Before commencing any Design, the Contractor shall carry out its own investigations sufficient to satisfy itself regarding all matters relating to the Project, the Site, and this Agreement.

4.3 Design Schedule

(a) Prior to the release of the first progress payment, the Contractor shall provide YEC with a Design Schedule satisfactory to the Project Manager, that describes the anticipated timing of the major design activities in sufficient detail to demonstrate to YEC that the Design shall be performed in accordance with the Work Schedule.

(b) The Project Manager may, at any time, and from time to time, request that the Contractor submits an updated Design Schedule.

4.4 Design Review

(a) Before commencing any Construction, the Contractor shall submit to YEC the applicable portion of the Design necessary to that Construction

(b) The Contractor shall submit to YEC the drawings listed in Schedule L in accordance with the schedule provided pursuant to Section 3.4(b).

(c) Within fourteen days, YEC shall review the Design submitted by the Contractor and the Project Manager shall advise the Contractor in writing that the submitted Design and design information:

(i) appears to be consistent with the intended purpose of the Project as anticipated by this Agreement;

(ii) appears to contain deficiencies or inconsistencies; or

(iii) is insufficient for the purposes of a review.

(d) If YEC identifies any apparent deficiencies or inconsistencies in the Design, the Contractor shall:

(i) provide further information to demonstrate to the satisfaction of YEC that the Design does not contain deficiencies; or

(ii) revise the Design, taking into consideration the apparent deficiencies or inconsistencies identified by YEC, and submit the revised Design to the Project Manager for review in accordance with 4.4(c).

4.5 Errors in Design

(a) The Contractor is responsible for all errors, omissions, or deficiencies in the Design.

(b) The Contractor shall give Notice to YEC immediately upon becoming aware of any errors, omissions, or deficiencies in the Design.

(c) The Contractor shall remedy at its own cost, to its own satisfaction and to the satisfaction of resulting errors, omissions or deficiencies in any part of the Construction that has been commenced or completed.

PART 5
CONSTRUCTION

5.1 Construction

(a) The Contractor will perform the Construction diligently, in a workmanlike manner, and in accordance with the highest industry practices used in Canada.

(b) Unless specifically authorized in writing by the Project Manager, the Contractor shall not commence Construction of any portion of the Work until that portion of the Design has been reviewed by YEC in accordance with Section 4.4.

5.2 Completion

(a) **Mechanical Completion and Punch List**.

(i) Notice of Mechanical Completion. As soon as construction of any discrete unit, part, system, or component of the LNG Facility (each, a

"**System**") has passed such pre-commissioning tests as may be required by the Specifications to be carried out prior to commencement of each System's preliminary operations and has otherwise satisfied the requirements of Mechanical Completion set forth in Schedule Q, the Contractor shall notify YEC by means of a written report, the "**Mechanical Completion Certificate**". The Mechanical Completion Certificate shall contain the Contractor's representation that such System or the LNG Facility has achieved Mechanical Completion. The Contractor shall not commence the introduction and circulation of hydrocarbons into any System until such System has satisfied all the requirements of readiness for hydrocarbons set forth in Section 5.2(a)(viii).

(ii) System and LNG Facility Mechanical Completion. Each System shall be mechanically complete upon the satisfactory completion of all applicable items described in Schedule Q and the LNG Facility shall be mechanically complete when all Systems have achieved Mechanical Completion.

(iii) System Punch List. The Contractor shall prepare and submit to YEC a punch list (the "**System Punch List**") which shall be submitted together with the Mechanical Completion Certificate for each discrete System and which shall set forth the outstanding items requiring completion or rectification before such System will meet the requirements of Final Completion. At the time Mechanical Completion is achieved for such System, the System Punch List for such System shall contain only those items, the lack of which or the failure to rectify or complete which (when considered individually or in the aggregate of all such items) does or will not prevent the safe, normal and continuous operation of the System in accordance with the O&M Manuals, Specifications, Design Basis and the other requirements of this Agreement.

(iv) Punch List. Following submission to YEC of each System Punch List with each Mechanical Completion Certificate, and the acceptance thereof pursuant to Section 5.2(a)(vii), the Contractor shall compile and update on a continuing basis until Final Completion a master list of all outstanding items requiring completion or rectification before the LNG Facility has met the requirements of Final Completion including (a) all outstanding items on each System Punch list, and (b) any other Work remaining to be completed before Final Completion (together, the "**Punch List**"). The Punch List shall contain:

A. those items, the lack of which or the failure to rectify or complete prior to Substantial Completion which (considered individually or in the aggregate of all Punch List Items for the LNG Facility), would preclude the achievement of Substantial Completion ("**Priority A Items**"), including but not limited to any defect in the

design or construction of any System or the LNG Facility, or any defect in the installation, operation or performance of a piece of equipment or a System, which defect (a) adversely affects the operations of any System or the LNG Facility safely and in compliance with any applicable Laws, (b) consists of the operation of a System or a piece of equipment, including the wear or degradation thereof, or the consumption of spares and consumables thereby other than in accordance with the manufacturers or vendor operations and maintenance expectations and recommendations, or (c) does or may prevent the normal and continuous operation of the LNG Facility in accordance with the O&M Manuals and the Specifications, Design Basis and the other requirements of this Agreement; and

B. those items, the lack of which or the failure to rectify or complete which would not preclude the achievement of Substantial Completion but which would preclude the achievement of Final Completion ("**Priority B Items**" and, together with Priority A Items, "**Punch List Items**"), including (but not limited to) any deficiency in the performance of the Work in accordance with the Specifications, Design Basis, Good Engineering Practice, or any other term or provision of this Agreement.

(v) Additional Punch List Items. YEC may at any time prior to Final Completion, promptly following the discovery thereof, notify the Contractor in writing of any deficiency in the Work relating to any piece of equipment, any System or the LNG Facility, and such deficiency shall be added to the Punch List for completion pursuant to Section 5.2(a)(vi); provided, however, that any such deficiency which constitutes a Priority A Item and which is discovered by or reported to the Contractor prior to Substantial Completion shall, at the election of YEC, (x) be remedied by Contractor prior to the achievement of Substantial Completion, or (y) be added to the Punch List for remediation prior to Final Completion.

(vi) Completion of Punch List Items.

A. The Contractor shall rectify or complete, prior to Substantial Completion, to the standards specified in this Agreement, including the Specifications, all Priority A Items which have been identified and placed on the Punch List prior to Substantial Completion.

B. The Contractor shall rectify or complete, prior to Final Completion, to the standards specified in this Agreement, including the Specifications, all Punch List Items which have not been satisfactorily rectified or completed prior to Substantial Completion.

C. In the event that the Contractor fails to commence in a reasonable period of time after Substantial Completion or to diligently proceed thereafter with the rectification or completion of Punch List Items remaining at or after Substantial Completion, YEC may, thirty (30) days after providing written notice to the Contractor and the Contractor failing to take appropriate action in response to such notice, arrange for the Punch List Items to be rectified or completed by YEC or YEC's agent or other designee. The cost thereof shall be certified by YEC and at YEC's option, shall be paid by the Contractor to YEC or deducted from the Price to be paid to the Contractor by YEC. The parties may in any event agree that any outstanding Punch List Item shall otherwise be deleted from the Punch List, subject to the mutual agreement of YEC and the Contractor and the payment or allowance of an appropriate amount in respect of such deleted Punch List Item.

D. In the event that YEC is required to suspend or reduce commercial operations to facilitate the Contractor's completion of Punch List Items following Substantial Completion pursuant to this paragraph or otherwise, the Contractor shall pay YEC the full amount of any and all losses, including any loss of profit and the additional costs of using diesel engines, resulting from such reduction or suspension of operations, not to exceed for any day the Delay Liquidated Damages rate set forth in Schedule I. Such payments shall be limited to 30% of the Price. YEC shall cooperate reasonably with the Contractor to schedule the completion of any outstanding Punch List Items during scheduled or unscheduled LNG Facility downtime and shall otherwise use commercially reasonable efforts to avoid losses due to suspension or reduction of commercial operations resulting from the completion of outstanding Punch List Items.

(vii) Delivery of Mechanical Completion Certificate. Upon receipt of a Mechanical Completion Certificate from the Contractor, the provisions of Section 5.2(d) shall apply. YEC's acceptance of a Mechanical Completion Certificate shall not preclude YEC from thereafter asserting to the Contractor in writing, promptly following the discovery thereof by YEC, a deficiency in such Work if such deficiency was not known to YEC at the time of such acceptance. YEC shall also at the time of signing the Mechanical Completion Certificate either approve the accompanying System Punch List, or within five (5) Business Days after receipt of the System Punch List, suggest such additions to and/or amendments of the System Punch List as YEC may reasonably consider to be necessary. The Contractor shall either incorporate such additions or amendments into the System Punch List or dispute such matters pursuant to Part 19.

(viii) Readiness for Hydrocarbons. Prior to introducing hydrocarbons into any System, the Contractor shall insure that, with respect to such System, all of the following conditions shall have been satisfied:

A. the System, and any other System into which hydrocarbons are not introduced but the Mechanical Completion of which is necessary for the safe operation of the relevant System, has achieved Mechanical Completion;

B. all equipment necessary for the safe operation of such System has passed all applicable test requirements;

C. all utilities and control systems necessary for the safe operation of such System have been commissioned;

D. all equipment that will contain hydrocarbons has been purged with nitrogen to 2% oxygen maximum;

E. all outstanding Priority A Items for such System have been satisfactorily completed; and

F. if not already set forth in the System's Mechanical Completion Certificate, the Contractor shall have delivered a written notice to YEC stating that all of the conditions set forth in Section 5.2(a)(viii)A to 5.2(a)(viii)E have been satisfied.

If the conditions set forth in Section 5.2(a)(viii)A to 5.2(a)(viii)E have not been satisfied to the reasonable satisfaction of YEC, YEC shall inform the Contractor of the reasons all of such conditions have not been satisfied and which items of Work are required to be completed to satisfy such conditions, and the Contractor shall complete such Work and submit a further notice to YEC pursuant to Section 5.2(a)(viii)F upon the completion thereof, to which the provisions of this paragraph shall apply.

(b) **Substantial Completion**. The LNG Facility shall be considered substantially complete ("**Substantial Completion**") upon the achievement of the following criteria and the delivery by the Contractor to YEC of a fully completed certificate from an officer of the Contractor, the "**Substantial Completion Certificate**", certifying the following to be true and correct:

(i) Mechanical Completion of the LNG Facility has occurred, and the LNG Facility is substantially complete in accordance with the Specifications, this Agreement, manufacturer's warranties, all requirements of Regulatory Authorities, applicable permits and applicable Law, and can be safely operated in accordance with the foregoing;

(ii) except for obligations not capable of being performed prior to Substantial Completion, obligations which are explicitly to be performed between Substantial Completion and Final Completion, and obligations which survive or remain following Final Completion, all Work required to be performed by the Contractor for the LNG Facility is complete and all equipment has been delivered to the Site and properly incorporated into the LNG Facility, except for Punch List Items (other than Priority A Items discovered by or identified to the Contractor prior to Substantial Completion, which shall be completed or rectified prior to and as a condition of Substantial Completion);

(iii) all LNG Facility operators have been trained in accordance with this Agreement;

(iv) the Completion Tests have been performed in accordance with Schedule K except for the Facility Reliability Test and documentation of the results of each Completion Test has been provided to and approved by YEC;

(v) as measured during the Completion Tests, the LNG Facility has achieved or exceeded each of the Performance Guarantees;

(vi) Delay Liquidated Damages, if any, have been paid in accordance with this Agreement;

(vii) the Punch List has been received and accepted by YEC, or any dispute with respect thereto has been resolved pursuant to Part 19; and

(viii) all Contractor supplied Spare Parts, including operating and capital spares procured by the Contractor at YEC's expense pursuant to Section 2 of Schedule G, have been delivered, inventoried and securely warehoused, except as otherwise provided in Section 3 of Schedule G.

Together with the Substantial Completion Certificate, the Contractor shall deliver to YEC a written report with respect to the test requirements listed above and the status of the Work in sufficient detail to enable YEC to independently determine whether Substantial Completion has occurred.

(ix) The Contractor shall achieve Substantial Completion on or before October 14, 2014 (the "**Guaranteed Completion Date**"), unless otherwise agreed to in writing by the Project Manager.

(x) In the event Contractor fails to achieve Substantial Completion prior to the Guaranteed Completion Date, the Contractor shall pay YEC on a monthly basis for the Delay Liquidated Damages at the rate set forth in Schedule I, with payment due from Contractor within ten (10) days following submission of an invoice from YEC. YEC may offset any such amounts

in whole or in part against amounts due to the Contractor under this Agreement.

(xi) YEC and the Contractor agree that Delay Liquidated Damages are not a penalty but represent a genuine and reasonable pre-estimate of the damages that YEC will suffer as a result of the happening of the specified event, and which the Contractor agrees with YEC that it would be difficult or impossible to quantify upon the happening of the specified event. The Contractor agrees with YEC that Delay Liquidated Damages shall be payable whether or not YEC incurs or mitigates damages, and that YEC shall not have any obligation to mitigate any such damages. The Contractor agrees with YEC that the Contractor has taken into account such Delay Liquidated Damages in its pricing of its compensation hereunder, that such Delay Liquidated Damages are integral to the provisions of this Agreement, and that YEC has relied on such Delay Liquidated Damages in entering into this Agreement.

(c) **Final Completion**. The LNG Facility will be deemed to be finally complete ("**Final Completion**") upon the achievement of the following criteria and the delivery by the Contractor to YEC of a certificate from an officer of the Contractor, the "**Final Completion Certificate**", certifying each of the following to be true and correct:

(i) Substantial Completion has occurred and all Punch List Items including all Priority B Items have been completed;

(ii) the Contractor's obligations under Section 5.8(b) and Schedule N to deliver Job Book, O&M Manuals and other documentation have been completed;

(iii) the Facility Reliability Test has been performed in accordance with Schedule K and documentation of the results of the test has been provided to and approved by YEC;

(iv) the Contractor has removed all of the Contractor's equipment pursuant to Section 18.6 and removed all waste material and rubbish from the Site and, to the extent generated by the Work, from the surrounding areas;

(v) the Contractor has provided a statutory declaration in a form reasonably acceptable to YEC stating that there are no outstanding liens associated with the Work; and

(vi) the Contractor has satisfied all its obligations under this Agreement other than the warranty obligations under Part 8 and any obligations that survive the termination of this Agreement.

(d) **YEC Acceptance of Completion Certificates**. Within ten (10) Business Days after receipt of the Mechanical Completion Certificate, the Substantial Completion Certificate or the Final Completion Certificate, YEC shall either (i) accept the certificate by having an authorized representative of YEC sign said certificate, or (ii) if reasonable cause exists for doing so, notify the Contractor in writing that Mechanical Completion, Substantial Completion or Final Completion has not been achieved, stating in detail the reasons therefor. In the former case, the date of such completion shall be deemed to be the date on which such completion was achieved. In the event YEC notifies Contractor that Mechanical Completion, Substantial Completion or Final Completion has not been achieved, and the Contractor disputes such notification, then the dispute may be immediately referred for dispute resolution pursuant to Part 19.

(e) **LNG during Start-up and Testing**. YEC shall arrange for the delivery of the first LNG shipment to occur by [September 15, 2014] (or such later date as is requested by the Contractor) following the notification procedure provided in Section 5.2(f)**.** In the event the Contractor determines that it will be ready to receive the first shipment of LNG earlier than [September 15, 2014], the Contractor may advise YEC of such, and YEC shall use commercially reasonable efforts to obtain an early delivery; provided however the YEC shall not be in breach of this Agreement and the Contractor shall be deemed not to have been harmed if YEC is unable to arrange for such earlier delivery.

(f) **Notice of Readiness for LNG**.

(i) 45-Day Notice. Not later than forty-five (45) days prior to the Expected LNG Date (the "**Start-up Period**"), the Contractor shall provide written notice to YEC of the seven (7) day period within which the Contractor expects YEC to begin delivery of LNG during the Start-up Period.

(ii) 10-day Notice. Not later than ten (10) days prior to the Expected LNG Date, the Contractor shall provide written notice to YEC of the date, within the seven (7) day period referenced in Section 5.2(f)(i) above, during which the Contractor expects YEC to deliver the first LNG shipment during the Start-up Period.

(iii) Start-up Notice. The Contractor shall provide written notice to YEC of the quantity of LNG required for the period following arrival of the first LNG truck and prior to Substantial Completion not less than seven (7) days prior to the required delivery date of the subsequent LNG trucks (the "**Start-up Notice**").

(iv) LNG Venting Prior To Substantial Completion. Prior to Substantial Completion, the Contractor shall take all reasonable steps to vent/purge or otherwise release the minimum quantity of LNG.

(g) **Right of Waiver**. YEC shall have the right, but shall have no obligation, to waive, defer or reduce any of the requirements stated in this Section 5.2 at any time. However, YEC's exercise of any rights hereunder shall apply only to such requirements as YEC may specify in writing and shall in no event relieve the Contractor of any requirements or other obligations not so specified.

(h) **Long-Term Obligations**. It is expressly understood and agreed by the parties that nothing in this Section 5.2 shall in any way modify or alter the Contractor's obligations relative to the Price, the Performance Guarantees or its ability to meet the Guaranteed Completion Date.

(i) **Delay In Delivery of First LNG Shipment**. If the first LNG shipment is not delivered at the time specified by the Contractor in the Project Schedule and in Section5.2(f), and the Contractor is required, solely due to such condition, to stop the progress of start-up, commissioning and testing activities, then the Contractor shall be entitled to a day for day extension of the Guaranteed Completion Date and the End Date.

5.3 Environmental Compliance

Without limiting the application of Section 3.2, the Contractor will comply with the *Forest Protection Act* (Yukon), *Environment Act* (Yukon), *Fisheries Act* (Canada) and the *Yukon Environmental and Socio-Economic Assessment Act* (Canada), and with all lawful directions of Regulatory Authorities and YEC for the protection of the environment, issued from time to time.

5.4 CEMP

The Contractor will develop a Construction Environmental Management/Work Plan (CEMP) in cooperation with YEC that will comply with YEC's Environmental Policy (attached in Schedule B), the Spill Response Plan-Jobsite (attached in Schedule B), and Section 5.3. The outline of the CEMP as well as reference documents are provided in Schedule B.

5.5 Health and Safety

Without limiting the application of Section 3.2, the Contractor will comply with the *Occupational Health and Safety Act* (Yukon), and YEC's safety program, policies, and procedures, and will provide YEC with all safety inspection reports, accident/incident reports, and minutes of safety committee meetings. The Contractor will review all applicable safety requirements with the Employees and Subcontractors and will provide YEC with confirmation of this procedure upon YEC's request.

5.6 Principal Contractor

Unless otherwise notified by YEC in writing, the Contractor will be the principal contractor, as that term is defined in the *Occupational Health and Safety Act* (Yukon), for the purposes of the Construction for any work area where the Construction is undertaken. If YEC notifies the Contractor that another person will be the principal contractor for all of part of the Contractor's

work, the Contractor shall comply with the directions of the principal contractor in accordance with the *Occupational Health and Safety Act* (Yukon) and any other applicable law.

5.7 Approvals and Permits

If the Contractor becomes aware of an approval, permit, easement, assessment or charge which YEC requires for the Project, but which YEC does not have, the Contractor will forthwith notify YEC in writing of such requirement.

5.8 Contractor's Documents

(a) The Contractor will keep written records of the Work, in a manner and form satisfactory to YEC. The Contractor will make the information contained in such documents available to YEC upon request, but YEC will not be bound by the information contained in such documents.

(b) At least 60 days before the start of commissioning of the Equipment, the Contractor will provide to YEC five (5) hard copies of the Job Books.

5.9 Format of Documents

All information available in electronic format shall be provided on disc or flash drive. All as-built drawings (and any modifications to them) will be provided in all of the following formats:

(a) hard copy paper;

(b) PDF format;

(c) either Microstation (.dgn) or Autocad (.dwg or .dxf) format, such drawings are to be provided on the title blocks provided by YEC; and

(d) the original source file format (where the originating program differs from those noted above in paragraph (c)).

5.10 Ownership of Documents

Reports, plans, sketches, drawings, graphic representations and specifications as instruments of the Work prepared by the Contractor or any of its Subcontractors pursuant to this Agreement, including all Design Data, will be the property of YEC. The copyright in such documents will belong to YEC and such copyright will continue for a period of fifty years from the date of their first publication. The Contractor may retain one copy of such documents for its records.

5.11 Use of Documents by YEC

YEC may use documents described in Section 5.8, 5.9 and 5.10 for any other purposes.

5.12 Supervision

The Contractor will at all times during the Term retain on the Lands supervision for the Work that is adequate in the opinion of YEC, acting reasonably.

5.13 Investigations and Contraventions

The Contractor will immediately advise YEC of any investigations by, or notices or directions from, any Regulatory Authority with respect to the Work and of any offences or contraventions the Contractor or its Subcontractors may have committed including contraventions or offences under any law of the Yukon or Canada, whether committed while performing the Work under this Agreement or otherwise.

5.14 Equipment

(a) Title to any Equipment shall pass to YEC on delivery to the Site, free from all claims, liens, charges, encumbrances or security interests of any kind whatsoever.

(b) The Contractor shall retain risk of loss or damage to the Equipment until Final Completion.

(c) The Contractor shall ensure that the Equipment and other materials furnished, manufactured or fabricated by the Contractor, or its Subcontractors, for incorporation into the Work, shall:

(i) be free from all latent and other defects or Deficiencies;

(ii) meet the Specifications, if so specified, and if not specified then be of the quality best suited for the required operating conditions and intended use and purpose of the materials and Work; and

(iii) be fit for the purpose for which the Equipment and materials have been manufactured or fabricated.

PART 6
SUSPENSION AND CHANGES

6.1 Suspension

The Contractor will forthwith suspend the delivery of the Work if and when directed to do so by YEC in writing, or upon receipt of direction to do so from any Regulatory Authority. YEC will give written notice to the Contractor when the suspension of the delivery of the Work under this Section 6.1 is to cease, and the Contractor will resume the Work as soon as reasonably practicable upon receiving such written notice.

6.2 Completion Date Adjustment

Where the Contractor's operations are suspended under Section 6.1 for reasons other than an event of Force Majeure or default by the Contractor, and as a result the Contractor cannot complete the Work by the applicable Completion Date, the Parties will, subject to Part 19, agree on a new Completion Date, having regard to the length of the suspension. Failing agreement by the Parties, the new Completion Date will be determined under Part 19.

6.3 Changes to the Work Required by YEC

YEC may require a Change to the Work as follows:

(a) any Change to the Work must be in writing from the Project Manager;

(b) the Contractor will not make any alterations to the Work unless it receives written notice from the Project Manager requiring a Change to the Work;

(c) if a Change to the Work, or a series of related Changes to the Work, increases or decreases the cost to the Contractor by more than $1,000, the Parties will agree in writing upon a fair adjustment to the Price and, failing such agreement, will determine an adjustment to the Price under Part 19; and

(d) where an adjustment to the Price is required due to a Change to the Work, the adjustment will reflect the actual, reasonable change in costs experienced by the Contractor as a result of the Change to the Work.

6.4 Changes to the Work Requested by the Contractor

The Contractor may request a Change to the Work as follows:

(a) any request by the Contractor for a Change to the Work must be delivered in writing to the Project Manager, and the request must set out the reason for the change;

(b) the Contractor will not make any alterations to the Work unless it receives written confirmation from the Project Manager that the Change to the Work requested under Section 6.4(a) has been approved; and

(c) Section 6.3(c) and (d) will apply to any Change to the Work approved under this Section 6.4.

PART 7
STATUS OF CONTRACTOR AND RELATED OBLIGATIONS

7.1 Independent Contractor

The Contractor is an independent contractor and not the servant or agent of YEC, and the Contractor has no authority to make any statements, representations or commitment of any kind or take any action that will bind YEC. Without limiting the generality of the foregoing, the Contractor is an employer for the purposes of the *Workers' Compensation Act* (Yukon), *Employment Standards Act* (Yukon), *Income Tax Act* (Canada), *Employment Insurance Act* (Canada) and the *Canada Pension Plan Act* (Canada) and for the purpose of any other legislation affecting employment, all as amended from time to time.

7.2 Contractor's Representative

The Contractor will designate in writing a representative (the "**Contractor's Representative**") who will have the authority to act on the Contractor's behalf in relation to the Contractor's obligations under this Agreement. The Contractor will advise YEC in writing of the name, address, e-mail, telephone and facsimile numbers of the Contractor's Representative within two Business Days of the Effective Date. YEC may rely upon the Contractor's Representative as having full authority in all matters relating to the Contractor's obligations under this Agreement. The Contractor will ensure that the Contractor's Representative is immediately available and accessible to YEC prior to and while the Work is being performed. Where, in the opinion of YEC acting reasonably, the Contractor's Representative fails to meet any of YEC's requirements, the Contractor will, on the written request of YEC, replace the Contractor's Representative with another individual acceptable to YEC within five Business Days. The Contractor will not change the Contractor's Representative without the written consent of YEC, which consent may not be unreasonably withheld.

7.3 Contractor's Superintendent

The Contractor will assign a dedicated superintendent, who may be the same person as the Contractor's Representative, who will be present on the site during all construction activity and will oversee all aspects of the Work on site.

7.4 Contractor's Expenses

The Contractor will promptly pay, and will ensure that its Subcontractors promptly pay, all charges for labour, materials, equipment and services used or contracted for by the Contractor and its Subcontractors in the performance of the Work.

7.5 Liens

The Contractor will pay all of its liabilities arising from its operations that might give rise to a lien upon the Lands or assets of YEC immediately upon such liabilities becoming due. If a lien is made or threatened to be made against the Lands or assets of YEC as a result of the activities of the Contractor or any of the Subcontractors, the Contractor will immediately take steps and

make payments, including the granting of security or payment into court, as are necessary to remove the lien or prevent the lien being made. . If the Contractor fails to release or obtain the release and discharge of any such lien or claim, then YEC may, but shall not be obliged to, discharge, release or otherwise deal with the lien or claim, and the Contractor shall pay any and all costs and expenses incurred by YEC in so releasing, discharging or otherwise dealing with the claim or lien, including but not limited to, legal fees on a solicitor-and-own-client (indemnity) basis. Any amounts so paid by YEC may be deducted from any amounts due to the Contractor whether under this Agreement or otherwise.

7.6 GST

The Contractor will register as required under the *Excise Tax Act* (Canada) for the collection and administration of the Goods and Services Tax (GST) and will advise YEC of its GST registration number. The Contractor will immediately advise YEC of any change in the Contractor's status under the *Excise Tax Act* (Canada).

7.7 Employees

The Contractor represents that the persons assigned to perform the Work will be qualified, skilled and competent to perform the Work. YEC may from time to time in its sole discretion require the Contractor to:

(a) assign additional Employees to perform the Work;

(b) reduce the number of Employees assigned to perform the Work; and

(c) remove any Employee from the performance of the Work who is, in YEC's sole discretion, careless, incompetent, unqualified, unsuitable or otherwise undesirable to perform the Work.

7.8 Project Meetings

The Contractor will attend weekly Project progress review meetings.

PART 8
WARRANTY

8.1 Warranty for the Work

The Contractor warrants to YEC that:

(a) the Design is free from deficiencies, including those arising from errors and omissions;

(b) for a period of twenty-four months from the Completion Date (the "**Warranty Period**"), the Construction is free from any defects in materials or workmanship; and

(c) during the Warranty Period, the Contractor will rectify any deficiency in the Design and repair or replace any defective material or faulty workmanship to the satisfaction of YEC.

8.2 Further Warranty Provisions

(a) Should the Contractor fail to remedy a deficiency or defect, or commence a remedy on a deficiency or defect, in accordance with Section 8.1, within 7 days of YEC providing a notice to the Contractor to remedy the same, YEC may proceed with any activities necessary to remedy the defect and the Contractor shall be liable to and shall indemnify YEC for any and all reasonable costs and expenses incurred by YEC in doing so and YEC may retain and deduct such amount from payments or other monies due, or which may become due, to the Contractor, howsoever arising.

(b) The Contractor further warrants any and all corrective actions it performs in respect of deficiency or defects appearing during the Warranty Period for a period of 12 months from completion of the remedial work.

(c) The Contractor shall immediately advise YEC's Representative of any defects in workmanship, defects, errors, omissions or mistakes in the Work that it discovers or becomes aware of during the Term or the Warranty Period.

(d) The Contractor shall perform its warranty obligations set forth in this Part 8 in a manner that keeps disruptions to YEC's continued operations at a minimum.

(e) The Contractor will obtain warranties from the Equipment manufacturers at least equal to the warranties set out in this Part 8. The Contractor shall be fully responsible for administering all warranties in relation to the Equipment during the Warranty Period. At the end of the Warranty Period, the Contractor shall assign to YEC any ongoing warranties for the Equipment.

PART 9
YEC OBLIGATIONS

9.1 Provision of Documents

Prior to the Contractor commencing the Work, YEC will provide the Contractor with copies of:

(a) any relevant portions of any permits, licenses, or leases held by YEC and required for the Work;

(b) any other plans, maps, or information reasonably required by the Contractor to perform the Work;

(c) the Environmental Protection Plan; and

(d) YEC health and safety policies.

9.2 Information

Upon receiving a written request from the Contractor, the Project Manager will provide timely information reasonably required by the Contractor to perform the Work.

9.3 Project Manager

YEC will, prior to the commencement of the Work, advise the Contractor of the name of the Project Manager in writing. The Contractor may rely upon the Project Manager as having authority in all matters relating to the Work and the Contractor will follow any written directions given by the Project Manager with respect to the Work.

9.4 Approvals and Permits

YEC will arrange to secure and pay for all necessary approvals, permits, easements, assessments, and charges required for the construction of the Project. If the Contractor provides written notice to YEC under Section 5.7 that an approval, permit, easement, assessment or charge is required for the Project, YEC will either obtain the required approval, permit, easement, assessment or charge, or provide written instructions to the Contractor to obtain such approval, permit, easement, assessment or charge, at YEC's expense.

9.5 Inspection

YEC may cause the Project Manager to conduct periodic inspections of the Construction as YEC, in its sole discretion, deems necessary. Such inspections will not unreasonably interfere with the Contractor's operations. The Project Manager will provide the Contractor with reports, verbally or in writing, of any inspections conducted by it.

9.6 Measurement

YEC will cause the Project Manager to measure the Construction for the purposes of determining the Contractor's compliance with this Agreement and for the purpose of determining the amounts of payments to the Contractor for the Work.

9.7 Non-Conforming / Defective Work

If a Party becomes aware of any material defective, faulty or non-conforming work relating to the Project, the Party will promptly notify the other Party in writing of any such defective, faulty or non-conforming work.

PART 10
PRICE AND PAYMENT

10.1 Price

(a) YEC will pay the Contractor the Price, not including Goods and Services Tax (GST), of _____ for the Work.

10.2 Payment

Subject to Section 6.3, YEC will pay the Contractor for the Work as follows:

(a) the Contractor will submit monthly progress payment invoices to the Project Manager showing the Contractor's estimate of the quantity of Work performed by the Contractor during the month and the amount the Contractor estimates is payable for that Work per the milestone payments set out in Schedule H;

(b) the Contractor will indicate on the invoices submitted under this Section 10.2 the exact milestone activities completed during the monthly invoice period.

(c) with each invoice the Contractor will submit a statutory declaration in a form acceptable to the Project Manager stating that all accounts for labour, Subcontractors, supplies, equipment and other indebtedness that may have been incurred by the Contractor in the performance of the Work have been paid in full and are fully discharged;

(d) the Project Manager will inspect the Work to determine the amount payable under the invoice and will advise YEC to pay an amount in respect of the invoice within thirty days of receipt of the invoice by YEC, which amounts paid prior to completion of all the Work will be treated as advances and will be based upon the Project Manager's estimate of the amount of the Work completed;

(e) any inspection or progress reports provided by the Project Manager to the Contractor prior to final inspection reports will be deemed to be estimates only;

(f) YEC will not be responsible for any loss sustained by, or cost incurred by, the Contractor if the Contractor pays any of its Employees, Subcontractors or suppliers on the basis of any inspection or progress report of the Project Manager, other than the final inspection report in respect of the Work;

(g) final payment to the Contractor will be based upon final inspection and measurement of the Work by the Project Manager and will be net of any advances made to the Contractor in respect of the Work and net of any Holdback;

(h) the Contractor will deliver the final invoice to the Project Manager within thirty days after completion of all of the Work and the invoice will be in a form and with content satisfactory to the Project Manager, acting reasonably; and

(i) subject to any deductions, the Holdback or set-offs under this Agreement, and subject to the Contractor having completed the Work to the Project Manager's satisfaction in accordance with this Agreement, YEC will pay the Contractor the amount set forth in the final invoice within thirty days after receipt of such invoice.

PART 11
HOLDBACK AND BONDS

11.1 Setoff and Holdback

YEC may deduct, withhold or setoff against any monies due or to become due to the Contractor under this Agreement:

(a) any amount due or accruing due to YEC from the Contractor;

(b) the amount of any claim, demand, or lien made or filed or that may be made or filed against the Lands, YEC or its land or other assets by the Contractor or anyone employed by it, or by any other person whomsoever by reason of any act or omission of the Contractor, provided that where a claim is made by a person other than the Contractor, YEC may, if requested by the Contractor, pay into Court on behalf of the Contractor an amount owing from YEC to the Contractor up to the amount of the said claim;

(c) such reasonable sums as YEC considers appropriate in respect of payments, assessments, or deductions required to be made by the Contractor under applicable statutes or regulations, where YEC might become liable for such payments, assessments, or deductions;

(d) an amount equal to the reasonable cost to YEC for services of a solicitor or accountant, where such services are required in respect of a failure by the Contractor to comply with any of the obligations of the Contractor under this Agreement; and

(e) ten percent (10%) from each payment due to the Contractor under this Agreement, which Holdback will be paid to the Contractor within forty-five days after Final Completion in accordance with the *Builders Lien Act* (Yukon), subject to Sections 11.1(a) to 11.1(d).

11.2 Bonds

Prior to the Contractor commencing the Work, the Contractor will deliver to YEC bonds or other securities satisfactory to YEC, acting reasonably, as follows:

(a) a performance bond in the amount of fifty percent (50%) of the Price; and

(b) a labour and material payment bond in the amount of fifty percent (50%) of the Price.

If the Contractor is in default under this Agreement, YEC may convert or negotiate such bond to the extent required to remedy the default.

PART 12
FOREST FIRES

12.1 Obligations of the Contractor

Without limiting the application of Section 3.2, the Contractor will at all times promptly comply with the requirements of the *Forest Protection Act* (Yukon), and with YEC's requirements, concerning the prevention, reporting, control, suppression and extinguishment of forest fires.

12.2 Prevention

The Contractor will take all reasonable precautions and make all reasonable efforts to prevent any forest fire starting and spreading from its area of operations on the Lands.

12.3 Control

The Contractor will immediately do its utmost to control and extinguish any fire, including an escaped slash fire, discovered by the Contractor burning on or in the vicinity of the Lands or any other lands or timber tenures, utilizing to the fullest extent the personnel, equipment, and resources available to the Contractor.

12.4 Reporting

The Contractor will, without delay, report to YEC and the relevant forest officer under the *Forest Protection Act* (Yukon) the existence of any forest fire on the Lands or near or adjacent to the Lands.

12.5 Closure

The Contractor will alter its hours of work or temporarily close down its operations in accordance with the *Forest Protection Act* (Yukon) or when directed to do so by a forest officer under the Act or by YEC because of unfavourable weather conditions or fire hazard conditions.

12.6 Equipment

The Contractor will at its expense maintain sufficient fire fighting equipment in good working order in accordance with the requirements of the *Forest Protection Act* (Yukon), and any other applicable Laws.

12.7 Claims

YEC and the Contractor will take all necessary steps to make any claims for reimbursement under the *Forest Protection Act* (Yukon), or insurance policies maintained by the Contractor.

12.8 Requirements

The provisions of all of this Part 12 will be in addition to, not in substitution for, the obligations of the Contractor under the *Forest Protection Act* (Yukon).

12.9 Indemnity for YEC Costs

Without limiting Section 14.1, where the Contractor, or any person working for or engaged by the Contractor, negligently or wilfully:

(a) causes a fire; or

(b) permits the escape of a fire, whether or not caused by the Contractor;

the Contractor will indemnify YEC for any loss, cost, or liability incurred by YEC as a result of the fire.

PART 13
IMPROVEMENTS

13.1 Improvements

The Contractor hereby acknowledges that no improvements and developments performed by the Contractor during the Term under this Agreement upon the Lands will become the property of the Contractor.

PART 14
INDEMNITY

14.1 Indemnity

(a) The Contractor will indemnify YEC and its respective directors, officers, employees and agents from and against all costs, expenses and liabilities:

(i) arising out of the failure of the Contractor, its agents, Subcontractors or the Employees, to comply with this Agreement;

(ii) arising out of or in connection with, whether directly or indirectly, the performance of the Work by the Contractor, its agents, Subcontractors or the Employees in such a manner that is negligent, or a default under this Agreement;

(iii) related to or arising out of any deficiencies in the Design; and

(iv) by the Contractor's agents, Subcontractors or the Employees against YEC, except to the extent YEC has been negligent, or in default under this Agreement.

(b) The Contractor will indemnify and save YEC harmless from all claims costs and demands, including legal fees on a solicitor-and-own-client (indemnity) basis, arising out of any patent, trademark, copyright or industrial design infringement pertaining to any equipment, machinery, materials, compositions, processes, methods or designs supplied by the Contractor, or its Subcontractors, in the performance of the Work.

(c) The indemnities provided by the Contractor under Section 14.1 will survive the expiration or termination of this Agreement.

PART 15
INSURANCE

15.1 YEC's Insurance

Without in any way limiting the liability of the Contractor under this Agreement, YEC will provide, maintain and pay the premiums for the following owner controlled project specific insurance coverages:

(a) **Course of Construction**: Prior to the commencement of the Work, YEC will obtain coverage under a "Builders Risk" insurance policy, in an amount equal to the Project value, with sub-limits for expediting expenses, fire fighting expenses, professional fees, debris removal, off-site storage and inland transit. The policy will also insure YEC's property in the care, custody and control of the Contractor or its Subcontractors. The policy will provide coverage on an "All Risks" basis, including perils of flood and earthquake, will name YEC as insured and the Contractor and its Subcontractors, if any, including any person employed directly or indirectly by either or both the Contractor and its Subcontractors to perform a part or parts of the Work, and will contain a waiver of subrogation in favour of the Contractor and its Subcontractors, if any. Coverage will be maintained until the Work is physically completed and accepted by YEC.

(b) **Construction Wrap-Up Liability**: Prior to the commencement of the Work, YEC will obtain coverages under a project specific "wrap-up" liability policy, in an amount of $10,000,000. The policy will contain a standard "non-owned" automobile liability extension and an endorsement for sudden and accidental pollution. The policy will name YEC as the insured and the Contractor and the Subcontractors, project and construction managers, architects, engineers and consultants, if any, while engaged in the Work as additional insureds and will contain cross liability and severability of interest clauses or equivalent wording.

The policy will maintain in force and effect a "Completed Operations Liability" endorsement coverage for a period ending not earlier than 24 months after the Work is physically completed and accepted by YEC.

(c) **Single Project Professional Liability**: Prior to the commencement of construction, YEC will purchase a project specific professional liability policy in an amount of $5,000,000. This policy will protect the lead consultant and its officers, directors and employees against any damages arising out of the professional services rendered. The policy will named the lead consultant as the insured. It will provide retroactive coverage back to the commencement of work on the Project and provide an extended maintenance period of 24 months after the construction has been physically completed and accepted by YEC.

In the event of a loss or damage, the Contractor will cooperate to the fullest extent with YEC and others in preparation and defence of a claim under the policies in this Section 15.1. When the extent of the loss or damage is determined, the Contractor will, at the option of YEC, proceed to restore the Work. Loss or damage will not affect the rights and obligations of either Party under this Agreement except that the Contractor will be entitled to such reasonable extension of the Completion Date as YEC may decide in its sole discretion.

15.2 Contractor's Insurance

Without in any way limiting the liability of the Contractor under this Agreement, the Contractor will provide, maintain and pay the premiums for any insurance it is required by Law to provide and the following insurance coverages:

(a) **General Liability Insurance**: General liability insurance will be in the name of the Contractor, with YEC as additional insured, with limits of not less than five million dollars ($5,000,000) inclusive per occurrence for bodily injury, death and damage to property including loss of use thereof. The insurance will be maintained continuously from commencement of the Work until the date of the expiry of any warranty period, and will contain cross liability and severability of interest clauses or equivalent wording. The policy will be endorsed to provide YEC with not less than thirty days' written notice in advance of any cancellation, change or amendment restricting coverage.

(b) **Automobile Liability Insurance**: Automobile liability insurance covering all licensed vehicles owned or leased by the Contractor will have limits of not less than five million dollars ($5,000,000) inclusive per occurrence for bodily injury, death and damage to property, in the following forms endorsed to provide YEC with not less than thirty days' written notice in advance of cancellation, change or amendment restricting coverage:

(i) Standard Non-Owned Automobile Policy including Standard Contractual Liability Endorsement. (This may be attached to the General Liability Insurance policy).

(ii) Standard Owner's Form Automobile Policy providing Third Party Liability and Accident Benefits Insurance and covering licensed vehicles owned or leased by the Contractor.

(c) **Contractor's Equipment Insurance**: All risks contractor's equipment insurance covering construction machinery and equipment owned or rented and used by the Contractor and/or its Subcontractors for the performance of the Work, including boiler and machinery insurance on temporary boilers and pressure vessels, will be in a form acceptable to YEC. The policies will be endorsed to provide YEC with not less than thirty days' written notice in advance of any cancellation, change or amendment restricting coverage. Subject to satisfactory proof of financial capability by the Contractor for self-insurance, YEC may agree to waive the equipment insurance requirement.

(d) **Workers Compensation**: The Contractor will comply with workers compensation or equivalent legislation that is applicable to it, including the payment of assessments and dues thereunder. The Contractor's Workers' Compensation Board registration number is: _____, in the jurisdiction of the Yukon. If the Contractor has workers compensation coverage by insurance, the insurance certificate must identify such coverage. At any time on request of YEC when the Contractor is registered with a Workers' Compensation Board, the Contractor will deliver to YEC, a statement of the applicable Workers' Compensation Board that:

(i) the Contractor is registered and in good standing, and

(ii) all persons performing the Work at the Project site who are not covered by the applicable Workers Compensation Act are covered under personal optional protection coverage available through the applicable Workers' Compensation Board.

15.3 General Insurance Provisions

(a) Unless otherwise approved by YEC in writing, the Contractor will ensure that all Subcontractors carry insurance in the form and limits set out in Section 15.2 and will provide proof of this insurance to YEC in a form satisfactory to YEC.

(b) The Contractor or its Subcontractors, as applicable, will be responsible for all deductible amounts under each of the insurance policies mentioned in Sections 15.1 and 15.2.

(c) Unless specified otherwise, the duration of each policy will be from the commencement of the Work until the date of the final certificate of completion.

(d) The Contractor will provide YEC with proof of insurance prior to the commencement of the Work and, if requested by YEC, will promptly provide YEC with a certified true copy of each policy exclusive of information pertaining

to premium or premium bases used by the insurer to determine the cost of the insurance. The Contractor will obtain and comply with all of YEC's and the insurer's requirements, including, but not limited to, allowable classes of vessels, maximum value concentrations, reports and claims handling procedures.

(e) If any of the coverage to be maintained by the Contractor or its Subcontractors under this Part 15 is not provided, or lapses for any reason whatsoever, the Contractor will, if requested to do so by YEC, at the Contractor's risk and expense, cease performing the Work until satisfactory evidence of coverage is produced.

(f) If the Contractor fails to provide or maintain insurance as required hereunder, then YEC will have the right to provide and maintain such insurance and give evidence thereof to the Contractor. The cost thereof will be payable by the Contractor to YEC on demand or YEC may deduct such amount for monies which are due to the Contractor.

(g) All required insurance policies will be with insurers licensed to underwrite insurance in the jurisdiction of the place of the Work and have a rating of A- or better in the current Best Insurance Report, published by A.M. Best Company, Inc. or any successor publication thereto.

(h) All required insurance policies will be considered primary and must not bring into consideration any other valid and collectible insurance.

(i) The Contractor will require that each insurer agree, in writing, to waive all rights of subrogation against YEC and its respective directors, officers, employees and agents.

PART 16
REPRESENTATIONS AND RELEASE

16.1 No Representations by YEC

The Contractor acknowledges that YEC has made no representations to the Contractor as to:

(a) the Specifications;

(b) the terms and conditions of any authorizations issued or to be issued under or in connection with the Work;

(c) the nature of the Lands;

(d) the nature of the Work or the difficulty or simplicity of the operations to be conducted by the Contractor in performing the Work; or

(e) the state, condition, or suitability of any roads or bridges;

all of which matters have been duly investigated by the Contractor prior to the Effective Date, and execution of this Agreement by the Contractor will be a release by the Contractor of YEC from any and all claims which the Contractor now has or may hereafter have in respect thereof.

16.2 Representations of the Contractor

The Contractor represents and warrants that it is knowledgeable and experienced in the type of work required for the Project under this Agreement. The Contractor acknowledges that it is being retained by YEC because of its knowledge and expertise in that regard.

16.3 Release

The Contractor, for itself and its successors, hereby releases and discharges YEC from all liability of YEC, whether arising in tort, contract, or otherwise for all loss, cost, damage, personal injury, or death suffered by or happening to the Contractor, its Subcontractors, or the Employees arising out of or attributable to or occurring during the performance of the Work by the Contractor or, from the operations or workings of YEC, except where such loss is occasioned by the negligence or default of YEC or its agents or servants.

16.4 Responsibility for the Work

No inspection, review or comment by YEC in relation to the Design or the Construction shall constitute acceptance by YEC of the Work, nor does it relieve the Contractor of responsibility for the quality of the Work or from any obligation to perform the Work in accordance with the requirements of this Agreement.

PART 17
FORCE MAJEURE

17.1 Force Majeure

If the Contractor is unable to perform the Construction or YEC is unable to make the Site available or undertake the Project as a consequence of fire, explosion, action or requirement of any governmental authority, strike, lock-out, labour disputes, flood, drought, embargo, riot, war or any act or consequence of war (whether or not there is a declaration of war), act of God or of the public enemy, delay or failure of carriers, the curtailment or suspension by YEC of its operations or the Project as a result of unfavourable market conditions, the need for YEC to reduce the Work because of unfavourable market conditions, or any other event or contingency, whether or not of the kind hereinbefore specified, which is beyond the reasonable control of a Party, including any of the foregoing events that cause YEC to alter the Project, the Contractor will not be liable to YEC for being unable to perform the Construction nor will YEC be liable to the Contractor for being unable to make the Site available or undertake the Project during the period of such event or contingency.

17.2 Notice of Force Majeure

A Party will give prompt written notice to the other Party of the occurrence of any event or contingency provided for in Section 17.1 which will affect its ability to perform under this Agreement, and such notice will include an estimate of the duration of the period of disability, and such Party will also give prompt written notice to the other Party when the event or contingency ceases.

PART 18
DEFAULT, INSOLVENCY AND TERMINATION

18.1 Default

Either Party may terminate this Agreement by written notice to the other Party where:

(a) the other Party defaults in any of its obligations in this Agreement, and that default continues for ten Business Days after written notice from the non-defaulting Party specifying the default, except that where the default is not curable in ten Business Days but the defaulting Party takes all reasonable steps to cure the default immediately upon receipt of the written notice from the non-defaulting Party, the non-defaulting Party will not terminate this Agreement; or

(b) the other Party has repeatedly defaulted under this Agreement (whether cured within ten Business Days under Section 18.1(a) or otherwise) and the non-defaulting Party has advised the other Party in writing that any subsequent default of like nature will result in a notice of termination under this Section 18.1.

18.2 Insolvency

YEC may terminate this Agreement upon written notice to the Contractor if:

(a) the Contractor becomes insolvent or makes a general assignment for the benefit of its creditors;

(b) the Contractor otherwise acknowledges its insolvency;

(c) the Contractor commits any act of bankruptcy, makes a proposal under the *Bankruptcy and Insolvency Act* (Canada), seeks protection under the *Companies Creditors Arrangement Act* (Canada) or commences liquidation proceedings, whether voluntary or otherwise; or

(d) a receiver is appointed for any of the assets of the Contractor.

This Agreement will not be considered an asset in the bankruptcy of the Contractor.

18.3 Remedies

The rights and remedies available to the Parties under this Agreement are in addition to and not a substitution for any rights and remedies otherwise available at law or equity.

18.4 Right of Termination by YEC

In addition to the termination rights provided in Sections 18.1, 18.2, 20.1 and 20.2, YEC may terminate this Agreement at any time by providing five Business Days written notice to the Contractor if:

(a) the Work has not been performed by the Contractor to the satisfaction of YEC acting reasonably;

(b) at any time YEC is not able to secure all permits and approvals required for the construction of the Project; or

(c) for any other reason.

18.5 Effect of Termination

(a) If this Agreement is terminated pursuant to Section 18.1, 18.2, 18.4, 20.1 or 20.2:

(i) all the rights of the Contractor under it will immediately cease except the Contractor's right to be paid for the Work performed up to the time of termination;

(ii) the Contractor will immediately cease performing the Work;

(iii) YEC will be entitled to possession of any improvements constructed by the Contractor on the Lands; and

(iv) the Contractor's obligations under Part 14 in respect of any activity of the Contractor prior to termination will survive termination.

(b) If this Agreement is terminated by YEC pursuant to Section 18.1, 18.2, 20.1 or 20.2:

(i) YEC may take possession of the Equipment and the Contractor's equipment, materials and plant and shall have the right to use the same to complete the Work;

(ii) the Contractor shall execute and deliver to YEC all documents required by YEC, and shall take all steps required by YEC, to assign to and fully vest in YEC the rights and benefits of the Contractor under existing agreements with the Contractor's Subcontractors, which are related to the Work; and

(iii) YEC may complete or have others complete the Work at the Contractor's expense.

18.6 Contractor Equipment Removal

Within thirty days after the termination of this Agreement and in any event as a condition of Final Completion, the Contractor will remove all of its equipment and supplies from the Lands, making good any damage caused by such removal. Any equipment or supplies not removed by the Contractor within thirty days may be removed or consumed by YEC at the Contractor's sole expense.

18.7 Extra Forces

Without limiting or being limited by any other right or remedy available to YEC at law or under this Agreement, if at any time and for any reason YEC believes, acting reasonably, that the Contractor may not complete the Work by the Completion Date, YEC may, by written notice to the Contractor:

(a) require the Contractor to focus its efforts on a particular part of the Work; and

(b) retain other persons to complete parts of the Work.

18.8 Price Adjustment

Where YEC provides the Contractor with notice under Section 18.7 and the reason that the Contractor would be unable to complete the Work by the Completion Date is something other than default by YEC or suspension under Section 6.1, the Parties will reduce the Price to reflect the cost to YEC to retain the persons under Section 18.7(b).

PART 19
DISPUTE RESOLUTION

19.1 Amicable Negotiation

Each Party will make bona fide efforts to resolve any disputes arising between them by amicable negotiations and provide frank, candid, and timely disclosure of all relevant facts, information, and documents to facilitate those negotiations. The Parties will use all reasonable efforts to conduct any dispute resolution procedures under this Agreement as efficiently and cost effectively as possible. If there is a dispute between the Parties under this Agreement a Party will provide written notice (the **"Dispute Notice"**) to the other Party of the nature of the dispute.

19.2 Reference to Executives

If a dispute cannot be resolved by negotiation between the Parties within ten Business Days after the date of receipt of the Dispute Notice, the Parties will attempt to resolve the dispute by negotiation with the assistance of two senior executives, one from each Party. The place of

negotiation will be Whitehorse, Yukon, Canada. Each Party will bear its own costs of the negotiation. The negotiation will be non-binding.

19.3 Arbitration

If a dispute cannot be resolved under Section 19.2 within twenty Business Days of receipt of the Dispute Notice, either Party may, by written notice to the other Party, commence arbitration. Arbitration will be administered under the *Arbitration Act* (Yukon). The place of arbitration will be Whitehorse, Yukon, Canada. Each Party will bear its own costs of the arbitration, and costs of the arbitrator(s) will be borne half by YEC and half by the Contractor. Arbitration will be final and binding on all Parties. Notwithstanding the foregoing, YEC may, in its sole discretion, at any time prior to a final decision of the arbitrator under this Section 19.3 refer the dispute being arbitrated to the courts for resolution.

19.4 Consolidation of Arbitration

All disputes referred to arbitration under Section 19.3 will be:

(a) held in abeyance until the Work has been completed; this Agreement has been terminated, or the Contractor has abandoned the Work, whichever is the earlier; and

(b) consolidated into a single arbitration.

19.5 Expedited Arbitration

Notwithstanding Section 19.4, YEC may, in its sole discretion, require that a dispute referred to arbitration under Section 19.3 commence forthwith.

19.6 Continued Performance

The Contractor will continue to perform its obligations under this Agreement while a dispute under this Agreement is being resolved.

19.7 Confidentiality

All negotiations and matters relating to an arbitration under this Agreement will be kept confidential and will not be disclosed to any other persons except those persons authorized by both Parties.

PART 20
ASSIGNMENT AND SUBCONTRACTING

20.1 Assignment

The Contractor will not transfer or assign this Agreement or any of the Work without the prior written consent of YEC, which consent may be withheld for any reason. Any such transfer or

assignment without such consent will be void. A transfer of any shares in the Contractor that results in a change in control of the Contractor will be deemed to be an assignment of this Agreement. For the purposes of this Section 20.1, "control of the Contractor" means beneficial ownership of more than fifty percent (50%) of its issued shares, having full voting rights in all circumstances, by one person or a group of persons not dealing with each other at arm's length. If the Contractor purports to transfer or assign this Agreement without first obtaining YEC's consent, YEC may terminate this Agreement forthwith upon written notice to the Contractor.

20.2 Subcontracting

The Contractor will not subcontract the Work or any part of the Work without the prior written consent of YEC, which consent may be withheld for any reason. If the Contractor purports to subcontract the Work or any part of the Work without first obtaining YEC's consent, YEC may terminate this Agreement forthwith upon written notice to the Contractor.

20.3 Binding on Permitted Subcontractors

If YEC consents to a Subcontract for any of the Work under Section 20.2, then:

(a) the Contractor will bind the Subcontractor to the terms of this Agreement insofar as they are applicable to the Work being performed by such Subcontractor;

(b) the Contractor will include in the terms of each such Subcontract provisions addressing compliance with Laws, supervision, training, and other issues identified by YEC and communicated to the Contractor from time to time, so that the obligations of such Subcontractors are consistent with the obligations of the Contractor under this Agreement;

(c) the Contractor will assume full responsibility to YEC for the acts and omissions of the Subcontractor; and

(d) notwithstanding the consent of YEC to such subcontracting, nothing contained in this Agreement or in any Subcontract will create a contractual relationship of any kind between the Subcontractor and YEC.

20.4 Copy of Subcontract

The Contractor will produce, on demand of YEC, a written copy of any Subcontract relating to the Work.

PART 21
CONFIDENTIALITY

21.1 Confidentiality

Except as required by law, a Party will not disclose to a third person who is not a Party any information, data, or documents supplied by one Party to the other Party under this Agreement or the existence of or the terms of this Agreement or any agreement entered into under this Agreement or related to the Project (collectively, the "**Confidential Information**") without the consent of the other Party, such consent not to be unreasonably withheld.

21.2 Exceptions

Section 21.1 will not extend to:

(a) information that is already in the public domain or becomes, after having been disclosed to a Party, generally available to the public unless the disclosure was made directly or indirectly by a Party in breach of this Agreement;

(b) prevent a Party from divulging Confidential Information in confidence to its affiliates and to its or their officers, directors, employees, agents, or other representatives who are required to have access to such Confidential Information for the purpose of that Party performing its obligations under this Agreement;

(c) prevent a Party from divulging Confidential Information in confidence to third parties (provided the third party is subject to similar confidentiality restrictions) who are required to have access to such Confidential Information for the purpose of that Party performing its obligations under this Agreement;

(d) prevent a Party from divulging Confidential Information to the extent necessary in connection with any dispute resolution commenced under this Agreement or any litigation commenced in respect of this Agreement;

(e) prevent a Party from divulging Confidential Information to the extent necessary, in confidence, to any financial institution for the purpose of obtaining financing for such Party or any of its affiliates; or

(f) prevent a Party from divulging Confidential Information to the extent necessary to any governmental or regulatory authority having jurisdiction over that Party.

If either Party is required to disclose Confidential Information under Sections 21.2(d) or (f), such Party will advise the other Party in advance of any such disclosure where possible in the circumstances so that the other Party may take such action as it considers necessary to maintain the confidentiality of such Confidential Information, and will take reasonable steps to limit the extent of the disclosure and to make such disclosure confidential under the applicable legislation, stock exchange rules, or rules of any governmental or regulatory authority having jurisdiction, as the case may be.

21.3 Survival

The obligations of confidentiality in Section 21.1 will survive the termination of this Agreement indefinitely.

21.4 Injunctive Relief

Each Party acknowledges that all Confidential Information is proprietary to the disclosing Party and that breach of this Agreement by a Party may result in irreparable injury to the other Party. Accordingly, in the event of any breach of Section 21.1 by a Party, the other Party will be entitled to seek and obtain an order of specific performance, restraining order, or injunctive relief, in addition to any other legal or equitable remedies provided under this Agreement.

PART 22
NOTICE

22.1 Notices

All notices, requests, demands, orders, or other communications under this Agreement will be in writing and will be deemed to have been duly given if signed by or on behalf of the Party giving the notice and delivered by hand, mailed by registered mail, sent by facsimile or e-mail to the other Party's address, facsimile number, or e-mail address to the other Party at the following address:

(a) if to YEC:

Yukon Energy Corporation
P.O. Box 5920
#2 Miles Canyon Road
Whitehorse, YT Y1A 6S7

Attention: Ed Mollard

Facsimile: 867.393.5323
E-mail: ed.mollard@yec.yk.ca

with a copy to:

Davis LLP
2800 - 666 Burrard Street
Vancouver, BC V6C 2Z7

Attention: P. John Landry

Facsimile: 604.605.3588
E-mail: pjl@davis.ca

(b) if to the Contractor:

[Address of Contractor]

Attention: [Name of Contact Person]

Facsimile: [Facsimile Number]
E-mail: [E-mail Address]

or to such other address as may from time to time be notified in writing by any of the foregoing. Any reference in this Agreement to a communication being in writing is made to emphasize the importance to written communication and not to suggest that any other communication should not be in writing.

22.2 Receipt of Notice

Any notice, request, demand or other communication will be deemed given and received:

(a) if delivered by hand or sent by facsimile (confirmed by telephone), upon receipt;

(b) if mailed, on the fifth Business Day after it has been posted as aforesaid at any postal station in Canada provided that if mailed, should there be at the time of mailing or between the time of mailing and the actual receipt of notice, a mail strike, slowdown or other dispute which might affect the delivery of such notice by mail, then such notice will only be effective when actually delivered; or

(c) if sent by e-mail, upon confirmation of successful transmission.

PART 23
GENERAL

23.1 Amendment

The only amendments which may be made to this Agreement are amendments in writing signed by the Parties.

23.2 Governing Law

This Agreement will be governed by and construed in accordance with the laws of the Yukon and the federal laws of Canada applicable therein and will be treated in all respects as a Yukon agreement.

23.3 Submission to Jurisdiction

Each of the Parties will:

(a) submit to the jurisdiction of the Yukon courts;

(b) if not incorporated or registered in the Yukon appoint an agent to receive service of any process in the Yukon; and

(c) if any appointed agent is required, notify the others of the name and address of its appointed agent.

23.4 Invalidity

If any one or more of the provisions in this Agreement are invalid or unenforceable, the validity and enforceability of the remaining provisions in this Agreement will not be affected.

23.5 Entire Agreement

This Agreement constitutes the entire agreement between the Parties relating to the subject matter of this Agreement and supersedes all prior proposals, requests for proposals, negotiations and agreements, whether written, oral, implied, or collateral, between the Parties. No representation or inducement whether made by statement or delivery of data or other information of any kind or nature whatsoever and whether in writing, orally, or in any other manner conveyed by any Party to any other Party survives the execution of this Agreement unless expressly made in this Agreement.

23.6 Further Assurances

As and so often as YEC may reasonably require, the Contractor will execute and deliver further and other documents, assurances, and conveyances as may be necessary to properly carry out this Agreement.

23.7 Enurement

This Agreement will enure to the benefit of and will be binding upon the Parties and their respective permitted successors and permitted assigns.

23.8 Waiver

The failure of either Party at any time to require strict performance by the other Party of this Agreement will not affect the first Party's rights under this Agreement to enforce this Agreement, nor will any such waiver of any breach of this Agreement be held to be a waiver of any succeeding breach of or waiver of any other provision of this Agreement.

23.9 Time of the Essence

Time will be of the essence of this Agreement with respect to all obligations to be performed by the Contractor and if YEC grants any extension of time under this Agreement, such extension will not be deemed to be or operate in law as a waiver on the part of YEC of this Section 23.9.

23.10 Execution

This Agreement may be signed by original, facsimile, or electronic mail and each executed counterpart will be considered to be an original. All executed counterparts taken together will constitute one and the same agreement.

The Parties have executed this Agreement as of the Effective Date.

YUKON ENERGY CORPORATION

By:

_____

Authorized Signatory
Name: David Morrison
Title: President

WITNESS

_____
(Signature)

_____
(Print Name)

_____
(Address)

CONTRACTOR

By:

_____

Authorized Signatory
Name:
Title:

WITNESS

_____
(Signature)

_____
(Print Name)

_____
(Address)

SCHEDULE A
TECHNICAL SPECIFICATIONS

DESIGN BASIS AND SCOPE OF WORK

1. MAJOR PROCESS SYSTEMS
2. BASIS OF DESIGN
3. PFD
4. P&IDs
5. DATA SHEETS
6. LOCATION PLAN, FIGURE 2 (FACILITY PLOT PLAN)
7. Initial LNG composition - 2 Sample analyses
8. 2010 National Building Code Seismic Hazard Calculation
9. Thermistor Readings as of 29 May 2013 showing the depth of permafrost in meters.

SCHEDULE B
TABLE OF CONTENTS FOR CEMP, and
ENVIRONMENTAL REFERENCE DOCUMENTS

The CEMP shall include the following general categories of information:

1. Preface

2. Definitions

3. Table of Contents

4. Introduction

    (a) CEMP purpose,

    (a) organization and framework

    (b) component plans

    (c) environmental policy (Contractor and/or YEC's policy)

    (d) applicable legislation, plus summary of permits, licences, and approvals

    (e) referenced/adopted standards, guides, and best management practices

    (f) project schedule and sequencing

    (g) project construction activities (mob/demob, equipment/material storage, access construction and maintenance, site prep, main construction components)

5. Project Roles and Responsibilities

    (a) Role of PM

    (b) Role of Superintendent/Supervisors/Leadhands/Foremen

    (c) Role of Environmental, Safety, Quality Designates

    (d) Role of all other personnel, sub-contractors, and suppliers

    (e) Notifications and Reporting (field inspections, incident reports)

    (f) Subcontractor requirements

6. Component Environmental Work Plans (for key hazards identified, e.g., waste management plan, erosion and sediment control plan, spill prevention and emergency response plan, air quality and dust control plan, hazardous material handling and storage)

7. Appendices (examples)

   (a) APPENDIX A – Environmental Work Plan Template (for subtasks that require specific planning – e.g., vegetation clearing)

   (b) APPENDIX B – Environmental Action/Checklist List Template

   (c) APPENDIX C – Environmental Incident Report Template

   (d) APPENDIX D – Waste Stream Profile Template

8. All contract personnel (prime and sub) are required to undertake a brief orientation to YEC's environmental programs and requirements prior to beginning any physical work on the Site. Alternatively, YEC and the selected contractor may agree to devolve this requirement and responsibility to the prime contractor, where after orientations will be provided by the contractor and shall include a full review of CEMP, and will include documentation of such orientations. YEC environmental representatives will have access to the orientations and the records of previous orientations.

The following environmental reference documents are provided:

Environmental Policy EN-001

Health and Safety Policy HS-001

EMS-EWP-001 SPILL RESPONSE PLAN-JOBSITE

SCHEDULE C
PROJECT SCHEDULE SUMMARY

[TO BE COMPLETED BY CONTRACTOR AND AGREED BEFORE CONTRACT SIGNING]

SCHEDULE D
Not used

SCHEDULE E
INTERFACE POINTS AND RESPONSIBILITY MATRIX

YEC will hire a Project Manager (the "YEC Project Manager") to manage the Contractor and the project interfaces between the Contractor and the other contractors hired to complete the total Project. The YEC Project Manager is intended to manage completion of the following tasks:

- Construction and commissioning of two new GE gas-fired engine modules (8.8 MW total capacity) along with related facilities (switchgear module, lube oil module);
- Construction and commissioning of LNG trucking unloading, storage (four cryogenic tanks for total initial capacity of 666 m^3) and vaporization infrastructure to be located on the new lands;
- Construction of the civil work (clearing, roads, foundations and undergrounds);
- Construction of a new substation and transmission line and communications to connect to existing 34 kV substation; and interconnecting natural gas, glycol/hot water, and firewater piping plus electricity supply and control wiring between the new facilities and the existing diesel plant to facilitate exchange of heat and gas and provide firewater to the site expansion area.

The Contractor will make its data requirements known to the YEC Project Manager who will coordinate the necessary exchange of data between contractors. The following are the anticipated interface points of the Contractor with other contractors and YEC:

1. Civil Contractor

A single civil contractor will prepare the site and construct the underground piping and all in-ground features and the foundations, slabs, trenches and impounding pit. The Contractor shall have the responsibility to define and coordinate the Contractor's civil requirements with the civil contractor. The Contractor will have no justification for a change order due to a mismatched interface with the civil contractor unless the Contractor can demonstrate that the civil contractor did not construct in accordance with approved construction drawings.

The Contractor will specify all underground conduits, piping and drains within the battery limits of the LNG storage area to civil contractor.

(a) All Conduits, piping and drains underground or within utility corridor shall be installed by the civil contractor.

(b) All sizes within this document are based on best information and may change as the construction drawings are developed by the Contractor and the other contractors.

(c) The following is a listing of the underground conduits, piping and drains and their interface points with the Contractor:

Service	Material	Interface points	Installation notes
Natural gas	TBD", schedule 40, carbon steel pipe	- Utility corridor within LNG vaporizer area at a point as defined by the Contractor.	- Pipe to be painted, wrapped and cathodically protected. - Pipe to be installed in utility corridor. - Pipe to be insulated outside of utility corridor.
Glycol-Water line from Power Plant to LNG area	TBD", schedule 40, carbon steel pipe	- Utility corridor within LNG vaporizer area at a point as defined by the Contractor. - Pipe will experience thermal cycling from 100 C to ambient.	- Pipe to be painted, wrapped and cathodically protected. - Pipe to be installed in utility corridor. - Pipe to be insulated and electrowrapped (freeze protected) outside of utility corridor.
Glycol-Water line to PP from LNG area	TBD", schedule 40, carbon steel pipe	- Utility corridor within LNG vaporizer area at a point as defined by the Contractor. - Pipe will experience thermal cycling from 100 C to ambient.	- Pipe to be painted, wrapped and cathodically protected. - Pipe to be installed in utility corridor. - Pipe to be insulated and electrowrapped outside of utility corridor.
Electricity supply	X" conduit	- Utility corridor within LNG vaporizer area at a point as defined by the Contractor.	-to be installed in utility corridor.
Instrumentation optic fiber	X" conduit	- Utility corridor within LNG vaporizer area at a point as defined by the Contractor.	-to be installed in utility corridor.

Notes:

i. Pipe sizes are approximate and may be used as contract pricing basis.
ii. Termination points can be precisely defined during detailed design. The Contractor shall coordinate with YEC Project Manager.

The following will be constructed by civil contractor. The Contractor will specify all concrete foundations requirements and in-ground structures to be constructed by civil contractor:

Name	Function	Construction notes
LNG tank pedestals	Foundation	- 2 pedestals per LNG tank four present and two future tanks - Pedestals for 2 future tanks to be constructed during install installation. - Load - TBD during detailed design. - Anchor bolt location to be coordinated with the Contractor. - Foundations to be designed to withstand LNG or fire without collapse.
LNG tank secondary containment	Containment	- Walls to be 2.5 feet above finished grade - finished grade to slope toward impounding pit and toward the trench. - Walls to be designed to withstand LNG or fire without collapse. - Area is 80' x 120'
LNG impounding pit	Containment	- 27' x 27' x 10' deep below grade and 1' lip above grade. - surface to be coated with 2" of perlite concrete **-The Contractor, as part of the Contractor's scope, shall provide a cover to minimize snow falling into the impounding pit**
LNG collection trench	Trench	- From truck unloading pad to impounding pit. Approx. 1' wide, 2' below grade, 1' lip above grade. - From process pad to impounding pit. - From storage area to impounding pit
Truck unloading pad	Support, drainage and containment	- Trucks will position back end of trailer over unloading pad. Pad approx. 16' x 20', 6" below grade with collection trench down the middle. - any LNG spills will fall onto pad, drain into trench and flow into LNG impounding pit. - 2 LNG pump foundations drain to unloading pad trench - 1 LNG truck fueling dispenser foundation drains to unloading pad trench
Truck unloading structure foundation and all piperack structure foundations	Structural steel support	
Process pad LNG equipment	Foundation, drainage and containment	- The following equipment will be positioned on the process pad that will drain to the LNG impounding pit: - 2 LNG vaporizers - 3 LNG pumps

		- The size of this pad is 8’ by 10’ - vaporizers will be supported from structure steel frame - pump foundation will be block pad - loads and anchor bolts to be coordinated with YEC Project Manager
Process pad non-LNG equipment	Foundation, drainage and containment	- The following equipment will be mounted on a pad that will drain to storm water: - 1 electric black start waste heat heater - 2 BOG compressors – note that BOG compressor - 1 BOG heat exchanger - odorization skid - sendout metering **- the black start heater, BOG compressors and BOG heat exchanger will be in a curbed area under roof supplied by the Contractor such that water leaked from compressor does not wash into storm water.** - The size of this pad is 8’ by 10’ - all equipment to be supported by block foundations - loads and anchor bolts to be coordinated with YEC Project Manager.
LNG Facility fence and gates		All facility fences and gates will be provided by others.

2. Power plant contractor

The power plant, new and existing, and the LNG Facility will be owned by YECand will be operated as a single facility. Therefore the SCADA system, control room and several utilities will be common to the two facilities. The Contractor should consider the fully expanded facility, i.e., 265,000 scf/hr + 10% contingency factor of natural gas sendout when specifying shared services and utility requirements.

(a) The SCADA system will be housed in the existing control room on the second floor of the main office building. The HMI for all controls installed in the Project will be displayed and controlled from this control room.

(b) The PLCs for the Project will be installed in the new 21m by 24m substation building to be constructed about 100 meters north of the LNG tanks. The Contractor will install the required PLC hardware, the cables between the LNG Area (as shown on the site plan forming part of the Specifications) and the PLCs, program the PLCs as required to provide a fully functional system and provide

Remote Transmitting Units, as required, to allow the PLCs to communicate in SCADA language with the necessary hardware in the existing control room.

(c) Installation of the control optic fiber conduit between the substation and the existing control room as well as the programming of the SCADA system will be by others. The Contractor will provide sufficient interface detail to allow the other contractor to terminate the optic fiber and to program the SCADA system.

3. Contractor Utilities

(a) The Contractor shall arrange for all construction utilities except those specifically listed immediately below.

(b) The Contractor shall arrange for toilets and self-contained wash facilities for construction crew.

(c) The Contractor will buy drinking water by bottles.

(d) YEC will provide:

(i) Water during construction at a point within the YEC compound. From this point, the Contractor will have to truck or hose the water to the LNG Area for use.

(ii) A location within the fenced YEC compound for 1 Contractor construction trailer. This trailer can be provided with electricity, a land phone line, and internet service.

SCHEDULE F
NOT USED

SCHEDULE G
SPARE PARTS; CONTRACTOR SCOPE OF SUPPLY.

1. Consumable Spare Parts. The Contractor shall provide, and the Price includes, any and all consumables necessary for the construction, start-up, commissioning and testing of the LNG Facility prior to Substantial Completion, including, but not limited to, all spare parts, special tools, chemicals, refrigerants, fuel (other than LNG) and lubricants for all Equipment and Contractor Equipment.

2. Special Tools and Operating Spare Parts.

2.1 The Contractor shall, in any request for bid quotation for any item requiring spare parts, include the following provision in such bid request:

> "Vendor shall submit, with proposal, a list of vendor-recommended spare parts for two years' commercial operation, including pricing (including any applicable discounts from base or list prices) and terms and conditions for the purchase of the recommended spares. In addition, vendor shall describe recommended intervals for repair/ replacement of parts, where appropriate, and shall provide information regarding repair shop locations and capacity with respect to future servicing of procured items. Pricing shall be valid for one year beyond the purchase order date. Vendor is hereby informed that the provision of such spare parts price list and the pricing of such spare parts shall be a factor in the technical and commercial evaluation of the product selection."

2.2 The Contractor shall, upon receipt of any price lists for special tools and operating spare parts for any item requiring spare parts (each, a "Spare Parts Price List"), deliver such Spare Parts Price Lists, together with supporting technical information and relative commercial rankings (excluding pricing), together with the Contractor's analysis and recommendations of the special tools and operating spare parts required for such items requiring spare parts, to YEC for YEC's consideration in connection with its acquisition of special tools and operating spare parts for the LNG Facility after Substantial Completion. The Contractor shall use reasonable efforts to obtain for the benefit of YEC discounts and favorable purchasing conditions for the procurement of spare parts and special tools, similar to such discounts and favorable purchasing conditions available to the Contractor, and shall take into consideration such spare parts pricing in its evaluation of the relative merits of competing bids from Equipment vendors and Subcontractors, and in such case where the technical and commercial evaluations of two or more competing bids are substantially the same, the Contractor shall procure such items, from the vendor or Subcontractor that provides the lower long term spare parts price.

2.3 YEC shall, not later than thirty (30) days following its receipt of any Spare Parts Price List and related information required by Section 2.2 of this Schedule and prior to the date the Contractor permanently demobilizes its procurement team having general responsibility for procurement, deliver to the Contractor YEC's order for spare parts and

special tools for the items requiring spare parts. The Contractor shall give YEC not less than sixty (60) days notice of the anticipated demobilization of the Contractor's procurement team. The Contractor shall, at no additional cost to YEC, other than as provided in Section 2.4 of this Schedule, procure for YEC's account the spare parts and special tools designated by YEC from the related vendor or Subcontractor. Spare parts shall not arrive prior to the Contractor's mobilization to Site and the Contractor shall be responsible for care of the spare parts as described in Section 2.4 of this Schedule.

2.4 The Contractor shall invoice YEC for, and YEC shall pay the Contractor, the actual cost (including freight, insurance, customs duties and clearing costs, and Taxes, if any) of such spare parts and special tools obtained at YEC's direction and for YEC's account. Prior to the earlier of Substantial Completion and the date YEC takes control of spare parts from the Contractor, the Contractor shall, at no additional cost to YEC, bear the risk of loss of, and be responsible to YEC for receiving, storing, inventorying, and handling in accordance with vendors' and manufacturers' requirements and specifications (including with respect to maintenance of any proper storage environment), all spare parts and special tools purchased for the account of YEC pursuant to this Agreement. Nothing herein shall be construed as limiting YEC's rights to independently procure spare parts or special tools for its use in connection with the LNG Facility.

3. Failure During Start-Up. Should any Equipment fail prior to Substantial Completion, spare parts and/or special tools may be withdrawn from YEC's stock of operations and maintenance stores so that the Equipment that failed may be returned to operating condition. The Contractor, at its sole expense, shall promptly, and in any event no later than Substantial Completion, replace all such withdrawn spare parts with new spare parts of the same type made by the same manufacturer, and return such special tools to YEC; provided, however, that the Contractor's failure to have so replaced such parts shall not be a requirement for Substantial Completion if the Contractor shall have commenced and diligently continued the procurement thereof as expeditiously as feasible and the delivery of such spare parts to YEC shall have been included as an outstanding Punch List Item. Title to any replaced part or spare part shall pass to Contractor upon its removal from the LNG Facility and the Contractor shall promptly remove such replaced part or spare part from the Site.

SCHEDULE H
PAYMENT SCHEDULE

[TO BE COMPLETED BY CONTRACTOR AND AGREED BEFORE CONTRACT SIGNING]
[The following is the recommended format for the Payment Schedule to be completed by Contractor:**]**

MONTH NO.	MILESTONE DESCRIPTION	MILESTONE VALUE	MONTHLY TOTAL	CUMULATIVE TOTAL	PERCENT VALUE	(1) CUM'L PERCENT
0	NOTICE TO PROCEED - XXXXXX 1, 2013	$ xx,xxx	$xx,xx3	$xx,xx3	x.x2%	x.x2%
	Monthly total		NTP Billing			x.x2%
1	Start Detailed Design	$xx,xxx			x.x1%	
	Write specifications for long lead items	$ x,xxx			x.x2%	
	Issue PFD's	$xx,xxx			x.x1%	
	Issue P&IDs	$xx,xxx			x.x2%	
	Issue One Line Diagrams	$xx,xxx			x.x1%	
	Monthly total		$xx,xx5	$xx,xx8		x.x9%
			Month 1 Billing			

(1) The percent values set out in the cumulative percent column are the maximum percentage of the Price that can be paid to Contractor up to that month of the project.

SCHEDULE I
LIQUIDATED DAMAGES

PART 1: DELAY LIQUIDATED DAMAGES

In the event that the Contractor does not achieve Substantial Completion by the Guaranteed Completion Date, the Contractor shall be liable for Delay Liquidated Damages in the amounts set forth below, subject to the terms of Section 5.2(b)(x) :

(i) 0.05% of the Contract Price for each day of delay in achieving Substantial Completion during the first 30 day period following the Guaranteed Completion Date.

(ii) 0.08% of the Contract Price for each day of delay in achieving Substantial Completion during the second 30 day period following the Guaranteed Completion Date.

(iii) 0.15% of the Contract Price for each day of delay in achieving Substantial Completion during the period after the 60th day following the Guaranteed Completion Date.

(iv) The Contractor's maximum liability for Delay Liquidated Damages shall be limited to ten percent (10%) of the Price.

PART II: PERFORMANCE LIQUIDATED DAMAGES

There are no Performance Liquidated Damages. The Contractor must satisfy the Performance Guarantees.

SCHEDULE J
PERFORMANCE GUARANTEES

1. **Basis Conditions.**

1.1 Definitions.

For the purpose of this Schedule J:

"Basis Conditions" means the conditions identified as "Basis Conditions" and set out for each completion test in Schedule K of the Agreement, to which the observed results of the completion tests are to be corrected in accordance with the completion test procedures.

"Gas Composition" shall be the LNG composition given in Schedule A.

1.2 Conduct of Tests.

The Performance Guarantees are based upon the assumption that tests will be conducted in accordance with the Basis Conditions and Completion Test Guidelines as set out in Schedule K.

1.3 Correction to Basis Conditions.

For the purpose of determining compliance with the Performance Guarantees, the results recorded during a Completion Test will be corrected in accordance with the Completion Test Procedures to take into account the effect of differences between the actual conditions at the time of such Completion Test and the Basis Conditions.

2. **Performance Guarantees.**

2.1 Design Guarantee.

Contractor guarantees that (1) the boil off gas from the LNG tanks, as demonstrated by calculations made in accordance with the Completion Test Guidelines set forth in Schedule K, shall be compressed and discharged into the sendout pipeline by the Boil Off Gas Compression System without the need to vent any excess LNG vapor (the "Boil Off Gas Compression System Guarantee"), and (2) the LNG Sendout and Vaporization System, as demonstrated by calculations made in accordance with the Completion Test Guidelines set forth in Schedule K, shall sendout at a rate of 260,000 scf/hr at 120 psig at 10C (the "LNG Sendout and Vaporization System Guarantee").

2.2 LNG Unloading System Guarantee

The Contractor guarantees that the LNG Facility shall be capable of unloading LNG from LNG trailers at a rate of not less than 300 gallons per minute, as determined during the LNG Unloading System Test (the "LNG Unloading System Guarantee").

2.3 Facility Reliability Guarantee.

The Contractor guarantees that as a condition precedent to achieving Final Completion, the LNG Facility shall transfer natural gas to the power plant at a rate, pressure and temperature as demanded by the power plant during the period of the test (the "Facility Reliability Guarantee"). During the Facility Reliability Test, all equipment within the LNG Facility shall function as designed.

SCHEDULE K
COMPLETION TEST GUIDELINES

1. General.

1.1 Completion Tests.

The Contractor shall perform or cause to be performed the Design Guarantee Tests, LNG Unloading System Test and Facility Reliability Test to demonstrate compliance with the Design Guarantees, Unloading System Guarantee, and Facility Reliability Guarantee set forth in Schedule J.

1.2 Design Guarantee Tests

Purpose: To demonstrate by calculation that the Boil Off Gas Compression System, and LNG Sendout and Vaporization System will meet or exceed the following guaranteed design values.

Timing: Prior to Mechanical Completion
Duration: N/A

(a) Boil Off Gas Compression System

Purpose: To demonstrate by calculation that the Boil Off Gas Compression System will maintain the storage tank pressure below the relief valve setpoint of six storage tanks.
Basis Conditions:
-Six LNG storage tanks are full
-LNG storage tanks pressure at 100 psig
-The LNG Facility is not sending gas to the power plant
Allowances: No allowance
Methodology: The Contractor shall provide calculations demonstrating that the Boil Off Gas Compression System meets the Boil Off Gas Compression System Guarantee.

(b) LNG Sendout and Vaporization System

Purpose: To demonstrate by calculation that the LNG Sendout and Vaporization System shall sendout at a rate of 260,000 scf/hr at 120 psig at 10C.
Basis Conditions:
-LNG storage tanks are 10% full
-LNG storage tanks pressure at 10 psig

-50% ethylene-glycol water solution circulating to vaporizers at 91 m^3/hour with an inlet temperature at the vaporizer of 84C.
Allowances: No allowance
Methodology: The Contractor shall provide calculations demonstrating that the LNG Sendout and Vaporization System meets the LNG Sendout and Vaporization System Guarantee.

1.3 LNG Unloading System Test

Purpose: To demonstrate the LNG Unloading System will meet or exceed the LNG Unloading System Guarantee.

Timing: The LNG Unloading System Test shall be conducted prior to and as a condition of Substantial Completion.

Basis Conditions:
-LNG storage tank pressure is 70 psig
-LNG trailer is 10 psig
Allowances: No allowance for test tolerance or instrument uncertainty
Methodology:
-The LNG trailer shall be offloaded as per the operating manual procedures.
-The LNG trailer will be returned with the minimum tank pressure, i.e., less than 15 psig.
-The custody transfer meter will be used to determine the total volume unloaded.
-The test will start when the unloading pump is cooled sufficiently to operate at full flow and will end when the LNG trailer goes empty as confirmed by suction drum, V-102, registering a low level.

1.4 Facility Reliability Test.

Purpose: The Contractor shall perform or cause to be performed the Facility Reliability Test to demonstrate that the LNG Facility can operate for an extended period at the desired rate of production and meet the Facility Reliability Guarantee.

Timing: The Facility Reliability Test shall be conducted prior to and as a condition of Final Completion.

Duration: Three (3) days.

Basis Conditions:
-Exporting gas to the power plant at a rate, pressure and temperature as demanded by the power plant.
-No installed spares shall be utilized for this test.

Allowances: Time shall be counted as satisfactory if the power plant has sufficient natural gas flowrate and pressure at design gas temperature to operate the generator engines for the duration of the test period.

In the event that transfer of gas during the Facility Reliability Test shall be required to be suspended due to a lack of LNG, the LNG Facility shall be deemed to have exported gas

at the necessary rate during the period of such LNG shortage as long as the lack of LNG shortage can be directly attributed to the YEC's failure to arrange an LNG shipment after having been given notice by the Contractor in accordance with Section 5.2(f) of this Agreement.

SCHEDULE L
DOCUMENTS FOR REVIEW

The following documentation shall be submitted to YEC in Word or PDF for approval as outlined in Section 4.4(b):

1. Project Execution Plan
2. Quality Management Program
3. Construction Site Safety Program
4. Plot and Equipment Location Plans, Facility & Equipment General Arrangement Drawings
5. Process Flow Diagrams (PFD's)
6. Piping and Instrument Drawings (P&ID's) – Issued for Design (Rev. 1, 2 etc) and Issued for Construction Revisions (Rev. 1, 2 etc), intermediate revision issues (Rev. 1A, 1B etc) will be issued for information only.
7. Engineering Standards & Equipment Specifications
8. Process and Equipment Data Sheets for all Tagged Equipment
9. Building Floor Plans and Exterior Building Elevations & Views
10. Electrical One Lines
11. Hazard Analysis Reviews/Conclusions
12. Area Classification Drawings
13. Logic Diagram
14. Recommended Spare Parts Lists obtained from Vendors
15. Pre-Commissioning Plans
16. Commissioning and Startup Procedures
17. As-built drawings and documentation
18. Copies of Written Communications with Government Agencies and Officials pertaining to construction permitting or construction site activities.
19. O&M Manuals

20. Training Plan

21. Process Control, SIS, F&G and ESD design documents

22. Underground project layout drawings, if any.

SCHEDULE M
JOB BOOK SPECIFICATIONS

Job Books shall include the following:

1. Engineering/Design

   (a) Drawing Index

   (b) Process Flow Diagrams (AB)

   (c) P&ID's (AB)

   (d) Plot Plan (AB)

   (e) Equipment Location Plan (AB)

   (f) Tagged Equipment List

   (g) Tagged Equipment Specifications

   (h) Line List

   (i) Instrument Index

   (j) Underground Piping Plans and Drawings (AB)

   (k) Underground Cabling Plan (AB)

   (l) Electrical one lines (AB)

   (m) Equipment Data Sheets

   (n) Instrument/Loop Diagrams * (AB)

   (o) Electrical Termination Diagrams * (AB)

   (p) Survey Bench Marks

   (q) Ladder Logic Diagram *

   (r) Site Elevation and Drainage Plan

   (s) Fire Protection Drawings and Specifications

   (t) Foundation Located Plans (AB)

AB = As Built
* = This information will not be provided in Job Book format, it will be provided in form and format available as a result of the design and construction process.

2. Purchasing and Contractor Supplied Information

(a) Copy of all Purchase Orders on major equipment (unpriced) with Addenda

(b) Contractor information for equipment purchased including

(i) Performance Curves

(ii) P&ID's

(iii) Equipment drawings

(iv) Priced, recommended spare parts

(v) Vendor Operating and Maintenance information/manuals

(vi) Material and fabrication certifications as applicable

(vii) Installation instructions

(viii) Specific guarantee information

(ix) Equipment list

(x) Instrument List

SCHEDULE N
START-UP AND COMMISSIONING RESPONSIBILITIES

PROJECT START-UP AND COMMISSIONING RESPONSIBILITIES

1. Concept

The purpose of this Schedule is to clarify each party's responsibilities during the construction, start-up and commissioning of the LNG Facility.

In general, the Contractor is responsible for providing the permanent facilities and equipment and for performing those activities required to provide YEC with a functional LNG Facility that is in compliance with the requirements of this Agreement.

All Contractor expenses associated with the precommissioning, commissioning, start-up and testing of the LNG Facility are included in the Price. Specifically included are all spare parts that are required to support precommissioning, commissioning, start-up and initial operation of the LNG Facility through Substantial Completion of each Systems and the LNG Facility as a whole. Separately, the Contractor shall provide the manufacturers' recommended spare parts list and operating spare parts to YEC in accordance with Schedule G of this Agreement.

YEC shall have the right of timely review and approval of all precommissioning, commissioning, start-up, testing and training plans, procedures and programs that the Contractor shall develop as required by this Agreement. YEC's review and approval shall not be unreasonably withheld.

YEC is responsible for two distinct phases of the Project: Operating & Maintenance (O&M) Mobilization and Commercial Operation. The O&M Mobilization phase includes those O&M activities prior to Substantial Completion which are required to establish an effective commercial operating environment. The Mobilization phase ends upon the Contractor's achievement of Substantial Completion and Commercial Operation commences.

YEC will be responsible for providing the following prior to Substantial Completion: operation and maintenance personnel; all supplies, equipment, small tools, vehicles, furnishings and appurtenances for those personnel that are required for their daily administration; and all required administrative and technical policies, procedures, processes and systems. The O&M personnel provided shall be pre-trained and experienced on similar plant and equipment. All of the O&M personnel's costs associated with this mobilization process prior to Substantial Completion will be deemed Mobilization Costs and will be borne by YEC.

2. Contractor's Responsibilities – Precommissioning, Start-Up & Commissioning

2.1 Precommissioning, Commissioning and Start up

The Contractor shall provide all supervision and craft personnel (other than operators provided by YEC), tools, equipment and materials required for precommissioning, commissioning and start-up, except LNG and electrical power that will be provided by YEC. YEC shall provide such operators to the Contractor for the purpose of participating in hands-on start-up, commissioning and performance testing of the LNG Facility until Substantial Completion. Such operators will work under the control and supervision of the Contractor until Substantial Completion. The Contractor shall be responsible for the acts and omissions of the operators prior to Substantial Completion when operators are working at the LNG Facility under the Contractor's direction, except to the extent that such acts or omissions constitute willful misconduct or gross negligence by the operators not attributable to the Contractor. The Contractor shall have the right to remove any operator who in its reasonable judgment poses a danger to persons or property or is otherwise unfit. YEC shall, at its expense, promptly replace such operator upon receiving notice from the Contractor.

The Contractor shall give YEC 90 days notice of the date that operators are required for in hands-on start-up, commissioning and performance testing of the LNG Facility. Such notice shall include details of the number of operators that the Contractors expects will be required for operation of the LNG Facility.

The Contractor’s Start-up and Commissioning responsibilities include:

- Start-Up personnel, including salary and expenses (travel, per diem, etc.)
- Vehicles for transportation of its personnel
- Development of detailed precommissioning (manual cleaning, air blowing, etc.), commissioning (inerting, cooldown, etc) and start-up procedures, for each system in accordance with the provisions of Schedule Q.
- Technical direction of installation services associated with equipment
- Administrative expenses, including office, supplies, postage, etc., Contractor’s Work.

The Contractor shall clearly establish:

- Systems packs (including marked up P&ID’s and procedures) for each System, and criteria for acceptance at each stage, including:
    - Mechanical Completion, identifying what paperwork will be required to demonstrate construction completion.
    - Pre-commissioning, identifying what paperwork will be required to be turned over by the Contractor to demonstrate proper per-commissioning.
    - Commissioning, including what paperwork will be required to prove Commissioning Completion.
    - Start-up, including what paperwork will be required to prove that the plant is ready for start-up

- A priority list and order of start-up for each System
- Completion testing for each system identifying what is required to be turned over and proven, refer to Schedule J.
- Substantial Completion for each System identifying what is required in documentation to handover the unit to YEC's Operations Group.

2.2 Vendor Representatives and Other Services

The Contractor shall provide all vendor representatives, engineers, consultants and such other services required by its Work throughout the precommissioning, commissioning and start-up activities and until Substantial Completion is achieved or the direct vendor or other service support is no longer required.

2.3 Training

The Contractor shall provide operator and maintenance training in all process and utility systems and safety aspects of the Facility. Operators will be trained in procedures for start-up, operation and shutdown of the Facility including training in all emergency systems and procedures. This includes a step by step review of the operating manual.

The Contractor shall develop and submit for approval an O&M Training Plan that shall, at a minimum, specifically address the following areas:

- training plan indicating plan and schedule of all training activities
- courses covering operation, maintenance and technical management
- training methods to be utilized (such as combination of short lectures and demonstrations)
- classroom training by vendor representatives for special equipment, as necessary.
- classroom training by Contractor Process Design staff for process design issues, basis of design and what the plant was designed to do and not to do.
- on-the-job training for YEC's staff by Contractor Start-up and Commissioning Staff.
- anticipated number of participants
- facilities and training hardware
- training manuals
- qualification(s) of training instructors
- training language (English)
- tests and examination procedures to determine performance of the trainee

2.4 Water, Chemicals, Lubricants & Hydraulic Fluids

The Contractor shall provide all chemicals, lubricants and hydraulic fluids, which are required to clean, condition, flush, fill and operate the equipment and systems, through achievement of Substantial Completion.

2.5 Special Tools, Shop Tools and Equipment

The Contractor will provide all Special Tools and equipment required for installation, precommissioning, commissioning, start-up, normal operation and maintenance of the systems and equipment.

2.6 Safety Equipment and Supplies/Portable Extinguishers

The Contractor shall provide and this scope of work includes all:

- Warning signs
- Permanent fire systems, hydrants, if any, will be provided by civil contractor
- Portable fire extinguishers

The number and type of permanent fire systems, portable fire extinguishers and safety stations supplied shall be determined by the applicable codes and standards for this type of facility, refer to CSA Z276-11.

The Contractor will not provide any first aid facilities or equipment, ambulances, fire trucks or other mobile firefighting equipment other than for its own needs.

2.7 Manuals and Procedures

The Contractor shall supply:

- Job Books in accordance with Schedule M of this Agreement
- O&M Manuals. The Operations Manual shall be provided in sufficient detail stating the valve-by-valve operation activities necessary to safely transfer LNG through the facility. The Maintenance Manual shall contain similar detailed information.
- Other training manuals and materials required by Contractor's training program.

3. YEC's Responsibilities - Mobilization

(Specifically excluded from the Contract Scope)

3.1 O&M Personnel

YEC will be responsible for recruiting, relocation, pre-training (as described in 3.3. below), payroll and any other O&M personnel expenses whether prior to Substantial Completion or after.

YEC will provide its O&M personnel to the Contractor at the Site for commencement of the Contractor's O&M on-the-job training program and performance of operating tasks in support of the Contractor's start-up and commissioning activities at the time defined in Section 2.1 of this Schedule N.

3.2 Not used

3.3 Pre-Training

YEC is responsible for providing O&M staff suitably qualified through prior training, education and experience on a similar plant design and similar equipment. YEC shall be responsible for all familiarization and any required pre-training for the LNG Facility O&M staff including but not limited to:

- Company Orientation
- Basic skills - mathematics, science, equipment principles, maintenance practices and operations practices, ability to read and understand all system drawings and documentation, basic computer literacy.
- Basic plant processes - basic principles of gas processing equipment
- Process plant operations - operating principles for gas processing facilities.
- Process plant maintenance - maintenance practices for gas processing facilities.
- Knowledge of principles of instrumentation and control systems including but not limited to control valves, relief valves, process control loops and general SCADA operations.
- Process plant repair – rigging, welding, plumbing & pipefitter, millwright, electrical, instrument, etc. (as these skills may be required for individuals' job requirements.
- Vendor maintenance/troubleshooting – except for LNG-specific vendor equipment.
- General Facility procedures and requirements
- Plant safety/security/firefighting safety and operating procedures including familiarity with process plant emergency response procedures
- General knowledge of and procedures for hydrocarbon product transfer
- Familiarity with and ability to understand environmental issues and Material Safety Data Sheets, etc.
- Government (local, provincial and/or federal) or other required certifications, training requirements, procedures and regulations for plant staff.
- LNG Fire Fighting training
- Equivalent PIC (Person in Charge) Training for LNG transfer operations at other LNG Facilities.
- Conversant in English to an approved level of fluency sufficient for plant operations.

YEC shall be responsible for managing YEC's training program and shall supply any instructors, training materials & supplies, off-site classroom facilities (if required), course tuition, travel or other expense associated with any pre-training activities or requirements.

YEC shall be responsible for any travel or other related expenses incurred by YEC's O&M personnel during the Contractor's training program

3.4 Spare Parts and Materials

Subject to the Contractor's obligations set out in Schedule G, YEC shall be responsible for obtaining all consumable spare parts and materials to operate the LNG Facility after Substantial Completion.

3.5 Chemicals, Lubricants & Hydraulic Fluids

YEC shall provide the warehouse stock of all required chemicals and lubricants sufficient for operation of the LNG Facility after Substantial Completion.

3.6 Shop Tools and Equipment

YEC will provide the tools and equipment necessary to maintain the plant after Substantial Completion. These items include, but are not limited to, the following general categories:

3.7 Office & Warehouse Furnishings and Equipment

YEC shall supply for use after Substantial Completion:

- Office furnishings, supplies & equipment
- Warehouse furnishings, supplies & equipment other than that specified as by the Contractor
- Miscellaneous equipment (carts, dollies, lifting devices, packaging equipment, etc.)

3.8 Vehicles, Boats & Mobile Equipment

YEC shall provide all vehicles, mobile equipment automobiles, buses, trucks (of any type or capacity), trailers, cranes and forklifts (including any ambulance or firefighting trucks or mobile equipment) necessary for the operation and maintenance of the LNG Facility.

3.9 Office Furnishings, Equipment and Supplies

YEC will be responsible for providing all office furnishings and equipment except stationary and built-in items.

3.10 Safety Equipment and Supplies

YEC shall supply safety equipment and supplies that comply with applicable codes, standards, Laws, regulations and to be consistent with safe operations and maintenance practices, including but not limited to:

- Personnel protective equipment (hard hats, safety glasses, safety shoes, protective clothing, etc.)
- Emergency equipment (stretchers, breathing apparatus, fire blankets, etc.)
- First Aid equipment

- Safety test equipment (explosive mixture meter, oxygen meter, hazardous chemical detectors, etc.)

3.11 Manuals and Procedures

YEC shall supply:

- Administrative policies and procedures manual
- Maintenance management procedures
- Agency compliance plans
- Qualification and training program
- Environmental procedures
- Accounting procedures
- Safety & Health procedures
- Emergency Response plan

SCHEDULE O
Not used

SCHEDULE P
LIST OF KEY PERSONNEL

Position Title	Name
Project Manager	TBD
Project Engineering	TBD
Lead Discipline Engineers	
Process	TBD
Piping / Mechanical	TBD
Electrical	TBD
Civil / Structural	TBD
Instrument / Automation	TBD
Project Procurement Manager (or equiv.)	TBD
Company Sponsor	TBD
Construction Manager	TBD
Pre-Commissioning and Startup Lead	TBD
QA Manager	TDB

SCHEDULE Q
MECHANICAL COMPLETION REQUIREMENTS

1. GENERAL

1.1 SCOPE

This Schedule supplements Section 5.2 - Completion and sets forth the definition of and describes the activities that are required to achieve Mechanical Completion.

1.2 DEFINITIONS

(a) "**Mechanical Completion**" shall mean, with respect to each System, the completion of the following work relating thereto: setting of the equipment on foundations; connecting equipment to other applicable equipment with piping, wiring, controls, and safety systems; ensuring that such equipment and such related operating systems are individually cleaned, leak-checked, lubricated, aligned, and point-to-point checked to verify that such equipment and such related operating systems have been correctly installed; that pre-commissioning tests required by the scope of work as set forth in this Schedule Q to be carried out prior to commencement of the preliminary system operations have been successfully completed; that applicable systems are ready for the safe introduction of hydrocarbons; and that the requirements of this Schedule Q have been completed as they apply to a specific System.

(b) "**Mechanical Completion Certificate**" shall mean the certificate issued by the Contractor as soon as Mechanical Completion of any discrete System has been achieved. The Mechanical Completion Certificate shall state that such System:

- has passed such pre-commissioning tests as may be required by this Schedule, to be carried out prior to commencement of preliminary System operations;
- is ready for the safe introduction of hydrocarbons; and
- has otherwise satisfied the requirements of this Schedule Q - Mechanical Completion Requirements.

Summary documentation shall be included as addenda to the Mechanical Completion Certificate evidencing the proper and satisfactory performance or completion of all appropriate checks, inspections, tests and other certifications and the witnessing thereof as required, in accordance the Contractor's detailed Operating Manual.

(c) The System Punch List submitted with the Mechanical Completion Certificate shall be prioritized. All Punch List Items shall either be classified as Priority A Items or Priority B Items.

2.

2.1 Manufacturer or Vendor Service Assistance

(Where responsibility is not indicated in Section 3)

Applicable manufacturers and vendors have confirmed that subject equipment and systems have been satisfactorily installed.

Applicable manufacturers and vendors technical assistance has been provided during training of YEC's operating and maintenance personnel.

A contact list of manufacturer's and vendor's technical service representatives' names and telephone numbers, including emergency contacts, has been developed and a copy provided to YEC.

2.2 Permits

YEC has been provided assistance, as requested, supporting YEC's procurement of necessary permits and certifications required for YEC's initial use of the Facility.

2.3 Instructions

The Contractor's commissioning plan & procedures have been developed by the Contractor and approved by YEC.

Manufacturer and vendor operating and maintenance (O&M) manuals have been organized, indexed, and provided.

Preliminary Job Books have been delivered.

YEC has been provided any other special manufacturer and vendor instructions pertaining to equipment startup and commissioning activities.

YEC's O&M personnel have completed training to the extent necessary for safe and efficient operation, prior to hydrocarbon introduction.

2.4 Removal of Rust Preventives

Protective materials used to protect equipment during the construction period that will be detrimental to equipment operation have been removed.

2.5 Lubricants

The listing of manufacturer's recommended lubricants have been submitted to YEC.

YEC has approved lubricant list.

Approved lubricants have been provided.

Required equipment and systems have been flushed and all flushing oils properly disposed of. See 3.4.

All equipment has been filled with operating lubricants and an equipment maintenance schedule through Substantial Completion has been approved.

2.6 Packing and Seals

Required mechanical seals and accessories have been properly installed.

Required permanent packing and accessories have been properly installed.

2.7 Temporary Bracing

All temporary supports, bracing or other foreign objects that were installed in vessels, ducts, piping, transformers, machinery or other equipment to prevent damage during shipment, storage and erection have been removed.

Any damage sustained has been repaired.

All other items as specified in Items 3.6 and 3.8 have been removed from the appropriate equipment.

2.8 Rotation and Alignment

Rotating machinery has been checked for correct direction of rotation and for freedom of moving parts before connecting the driver.

Cold alignment to the manufacturer’s tolerances has been completed.

Vendor representatives have witnessed critical installation activities as required by vendor warranty obligations.

2.9 Tie-ins at Unit Limits

YEC has been provided and approved the current schedule for tie-ins.

All new system tie-ins have been completed.

All existing system tie-ins have been prepared for safe execution.

2.10 Leak and Pressure Tests (See 3.6)

Required non-operating leak and pressure tests have been completed in accordance with applicable codes, specifications and regulations.

YEC has witnessed and signed off designated tests.

All test media has been properly disposed of.

Note: Pressure vessels and heat exchangers pressure tested in the fabricator's shop will not require testing in the field if shop testing is documented and witnessed as agreed with YEC. Even if already shop tested, however, such individual items of equipment may be included in the testing of attendant piping systems whenever practical and approved by YEC.

2.11 Inspection

Required shop inspections have been completed.

Erected facilities have been inspected for conformance with flow diagrams, construction drawings, vendor prints and specifications.

Materials installed have been inspected for specification compliance and material traceability reports, as required, are complete and available.

Systems and plant have been inspected and verified. Exceptions are noted and properly categorized on Punch List.

Required third party special inspections have been completed.

If required, field safety inspections per YEC's plant safety and health manual have been completed.

Note: Shop inspected equipment will not be reopened for inspection in the field except as specifically noted in 3.1.

2.12 Pressure/Vacuum Safety Relief Devices

YEC has been provided required calculations and design basis for all safety relief devices.

YEC has been provided composite list of all pressure settings.

Required bench testing have been completed.

All mechanical safety devices have been tested, adjusted and sealed as required.

2.13 Flushing and Chemical/Mechanical Cleaning

(Except as noted in 2.14, 3.3, 3.4, 3.8 and 3.10)

Equipment and systems have been mechanically cleaned of all trash and construction debris.

2.14 Temporary Screens, Strainers, and Blinds

All required temporary strainers and screens have been provided and properly installed.

Strainers have been cleaned during circulation.

Strainers have been removed when system is adequately cleaned.

Blind specifications and identification coding have been provided.

Required blinds have been provided and installed.

2.15 Purging/Inerting

Required purge/inerting connections have been installed.

Where required, purge materials have been provided.

Where required, inerting materials have been provided.

2.16 Drying Out

Where required, temporary facilities for dry out of systems, refractories and linings have been provided and drying out procedures have been completed.

2.17 Housekeeping

All excess materials, temporary materials and scaffolding have been removed; areas around equipment and systems have been rough swept or raked; all trash in work area has been picked up, removed and properly disposed of.

An adequate housekeeping program has been implemented to maintain safe operating conditions in equipment and system areas from mechanical completion through substantial completion.

2.18 Maintenance, Spare Parts, and Special Tools

Equipment has been protected from normal weather conditions, corrosion or damage through Substantial Completion.

Equipment maintenance program has been provided to protect systems and equipment through Substantial Completion including the cleaning of strainers.

YEC has been provided with manufacturer/vendor's list of recommended spare parts.

Contractor-provided pre-commissioning and commissioning spare parts and special tools have been provided.

3. DETAILED PROCEDURES CHECKLIST

In addition to the work responsibilities described in Section 2, the detailed procedures outlined below further define the Contractor's Mechanical Completion criteria for specific systems and items of equipment.

3.1 Vessels

Vessels have been opened after erection and any internals put in place.

Vessel internal and external manways have been opened once for inspection by YEC or the tank supplier.

As applicable, vessel dry out has been completed, vessel opened and materials that are designated in 2.16 have been installed.

3.2 Shell and Tube Exchangers

Required pressure tests have been performed in accordance with the applicable codes and specifications.

3.3 Fired Heaters

Final construction inspection of heaters has been completed if fired heaters were opened by the Contractor in the field.

3.4 Pumps, Compressors, and Drivers

Baseplates and soleplates have been final leveled.

Piping connected to pumps, compressors and drivers has been inspected and any pre-operational excess piping stresses at connection points has been eliminated.

Where specified, chemical cleaning and final assembly of lube and seal oil systems has been completed. All wastes and cleaning media have been properly disposed of.

Where specified, the lube oil, seal oil, and oil cooling systems have been charged with flushing oil and circulated for cleaning purposes. Flushing oils have been properly disposed of. See 2.5.

Lube oil, seal oil, and oil cooling systems have been final charged with operating oil recommended by the manufacturer.

3.5 **Tanks**

Any internals requiring field installation have been installed.

Required tank and internals have been tested. Test water has been properly disposed of.

3.6 Piping Systems

YEC has been notified of test schedule. (See 2.10)

All required piping has been hydrostatically or pneumatically tested as required by codes and specifications. Test water has been properly disposed of.

All field pressure tests have been witnessed.

Flanges, threaded joints and field welds have been insulated or painted after the specified testing of each system has been completed.

Pipe hangers, supports, guides, expansion joints and other pipe specialties have been inspected for the removal of all shipping and erection stops and for the correctness of cold settings for the design service.

YEC has been provided cold / hot setting instructions.

3.7 Electrical Power and Lighting Systems

YEC has been notified of test schedule.

Insulation tests on all wiring (except lighting wiring) have been completed using a megohmmeter.

Insulation tests on all motors and transformer windings (from phase to phase and phase to ground) have been completed using a megohmmeter.

Grounding system tests have been completed to determine the continuity of connections and the value of the resistance to ground.

Cathodic Protection Systems have been installed and tested.

Oil sample breakdown tests have been completed on all oil from oil insulated transformers.

Electrical gear has been charged with oil and/or other media as required.

YEC has been delivered a complete listing of the proper settings for all safety devices set or provided by the Contractor for each system

3.8 Instrument and Control Systems

All non-operating checks have been conducted to ensure instrument operability (i.e. Remove all shipping stops; check pointer travels; and verify instrument capability to measure, operate and stroke in the direction and manner required by the process applications and the instrument data sheets.)

Instruments have been bench or field calibrated with standard test equipment and all required adjustments and control point settings have been made.

All transmission and control tubing has been cleaned by blowing with cooled and filtered clean air before connecting to instrument components.

All air supply headers have been cleaned by blowing with clean air and checked for tightness.

Pneumatic control circuits have been leak tested.

Piping from instruments to process piping has been checked for tightness.

All system components have been installed, connected and their conformance to specifications and design criteria for function, ranges and settings verified using dummy transmission signals as needed.

All electrical signals and alarm wiring has been continuity checked for correct source of power polarity.

All thermocouples have been checked for proper joining of wires, position of elements in wells, proper polarity and continuity of receiving instrument.

All SCADA & PLC’s have been function tested to validate their functionality with respect to the plant design requirements, have display/reporting functions in accordance with their design requirements and have interface functionality as intended.

3.9 Fire water System

Inspections confirming the completeness and correctness of installations have been completed as well as any non-operating checks required.

Required fire-fighting chemicals and portable equipment (hoses, fire extinguishers and related equipment) have been provided and installed.

3.10 Building and Accessories

Inspections confirming the completeness and correctness of installations have been completed as well as checks of all heating, ventilating and air-conditioning equipment.

Required local government compliance certifications have been obtained covering all plumbing, electrical, and fire protection.

APPENDIX D – BASIS OF DESIGN

CLIENT: **Yukon Energy Corporation**			Project Number: XXXX
LOCATION: **Whitehorse, Yukon, Canada**			Rev. B 12-8-13
PROJECT: **LNG for Power**			**Design Basis**
Section	**Unit**	**Design**	**Comment**
Guarantee Conditions			
Total net storage capacity	m3	740	
Net capacity of LNG storage tanks	m3	3@166.5 each & 2 future @120 each	Shop fabricated horizontal VJ tanks @ 90% full
Maximum vaporization sendout rate	m3/hr	7500	28.6 MW at 40% efficiency power generation requirements + 10% design allowance
	SCF/h	265,000	
Power Generation Capacity	MW	28.6	New natural gas generators plus possibly existing diesel generators with fuel blending.
Power Generation Efficiency	%	40%	Basis of Design Calculations Efficiency
Send-out pressure at maximum sendout rate	barg	6	Engines require between 5.3 and 8.0 barg
	psig	87	
Sparing philosophy for equipment and utilities	see list of operating, standby and backup.	N+1	For details see equipment specifications.
LNG Site Conditions			
Site elevation	m	approx 700	
Frost line depth	m	5+ meters	
Emissions			
NOx	tonnes/yr	0	No gas fired equipment. Vent/Flare is for Commissioning and emergency only.
CO	tonnes/yr	0	
VOC	tonnes/yr	0	
PM	tonnes/yr	0	
CO_2	tonnes/yr	0	
Water discharge	liter/yr	0	No process water discharge
Seismic			
Maximum considered earthquake design philosophy		CSA Z276 design basis	See: http://www.earthquakescanada.nrcan.gc. ca/hazard-alea/interpolat/index_2010-eng.php Use Site Coordinates: 60.6958 North 135.0469 West
Systems designed to operating basis earthquake	OBE	yes	
Systems designed to safe shutdown earthquake	SSE	yes	
Ground motion detection: identify systems that alarm and shutdown		none	
Climatic Conditions			
Minimum design temperature	C	50	
Maximum design temperature	C	60	
Barometric pressure	kPa	101.35	
Barometric pressure rate of change	kPa/hr	2	
Wind direction	from	Prevailing from south	
Design wind speed	kph	TBD	
Max daily Rain fall between 1971-2000	mm/hr	45	
Max Snow depth between 1971 and 2000	cm	100	
Feed Gas			
Source			
Natural gas specifications, range of conditions	Composition, molecular weight, HHV, LHV		See Appendix Spectra Train C & D Representative Gas Compostion Samples dated March 30, 2010

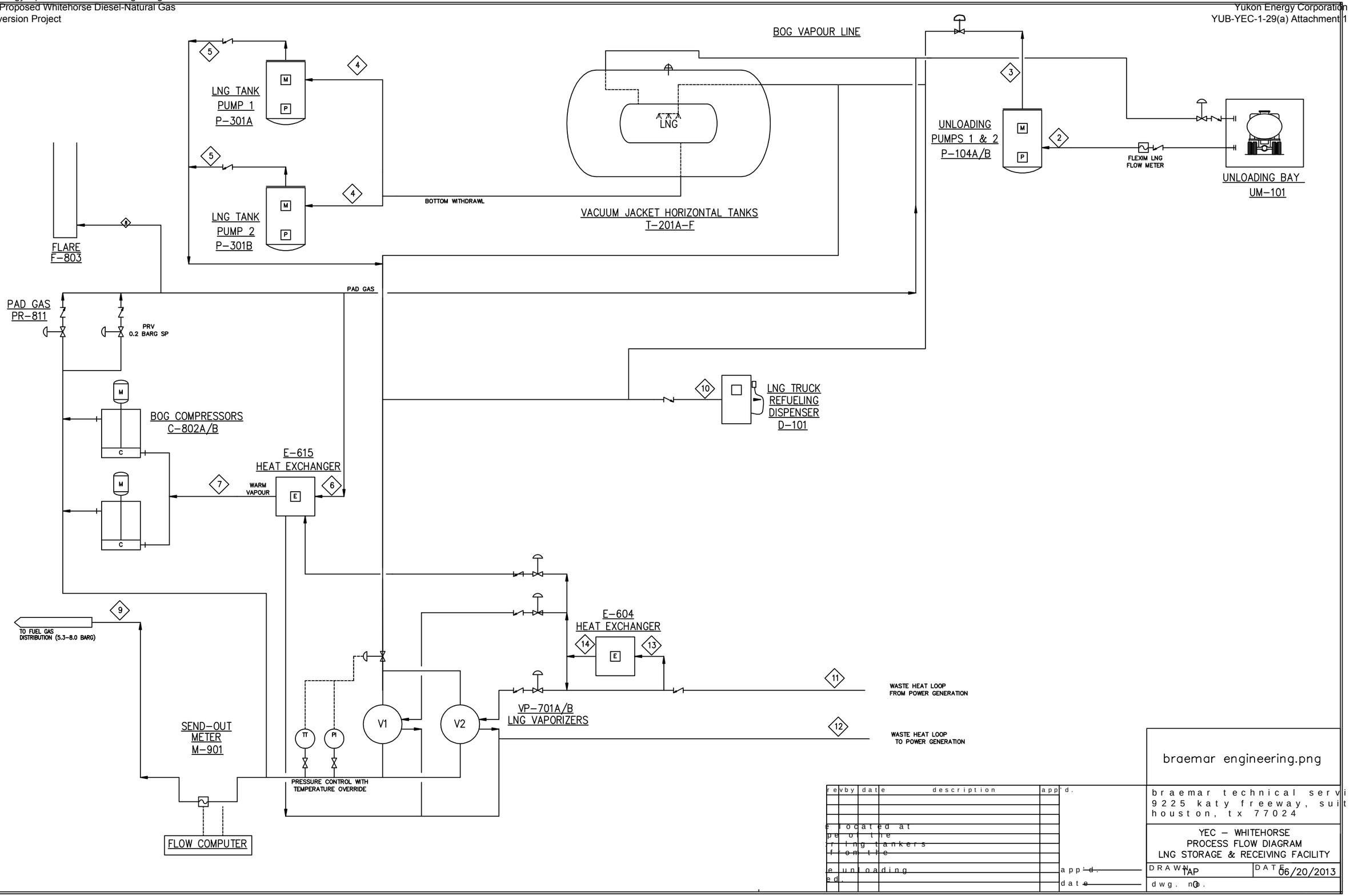
Section	Unit	Design	Comment
Storage			
Type of tank		Vaccum Jacketed Horizontal Shop Fab	
Foundation		Concrete	
Secondary containment		Inground Concrete	
Number of tanks		5	
Working capacity per tank	m3	3@166.5 each	working capacity = 90% of gross capacity
Design pressure	psig	100	
Design vacuum	psig	TBD	
Working pressure	psig	100	
Specific gravity		0.47	Per CSA Z276
Maximum Boiloff rate	percent (%) per day	0.0025	
Sendout Pumps			
Type of pump(s)		Pot Mounted	
Number of pumps operating and spare		N+1	3 at 50% VFD. All 3 foundations installed initially, but only two pumps installed intially
Design flow rate	m3/hr	6	per pump
Head at rated flow	m	198	
Head at shutoff	m	TBD	vendor specific, may vary
Maximum LNG specific gravity		0.47	
Vaporizers			
Vaporizer type		Vertical Stainless	Hot water/glycol loop from waste heat with circulating pumps
Vaporizers operating and spare		2	2-100%
Emission control	tonnes/yr	NA	
Operating flow rate each	m3/hr	7500	Primary Source - waste heat - generator jacket, secondary electric boiler for blackstart
	SCF/h	265000	
Operating pressure	bar	8.3	ANSI 150 Flanges
	psig	120	
Design discharge temperature	C	40 max	Temperature at power plant generator engine must be between 10C and 40C.
		13 min	
Vapor Handling			
BOG compressor	type	Recip	Electric drive
BOG compressors operating and spare		2	2-100%
Pressure compressor discharge pressure	bar	9	Discharge pressure sufficient to enter natural gas line to power plant
	psig	131	
Maximum vapor flow rate	m3/hr	64	
Flares			
Flare type		TBD	
Flare sources and rates	m3/hr	120	three 166 m3 and two 120 m3 storage tanks with 0.25% boil off rate (max) + 100% contingency
Fuel Gas			
Source		NA	No fuel gas system
Flow rate		NA	
Pressure levels		NA	
Minimum temperature at pressure levels		NA	
Design temperature at pressure levels		NA	
Odorized		NA	
LNG Trucking			
Number of trucks per year		TBD	
Number of trucks per day loading		NA	trucks may be loaded in the spring to de-
Number of trucks per day unloading		1/day	Will be a B-train-2 trailers by one tractor
LNG unloading rate	liter/min	1140	vendor specific, may vary
LNG truck fill rate	liter/min	TBD	max possible from all LNG tank pumps

Section	Unit	Design	Comment
Electrical			
Main power utility supplier		YEC	YEC is the electricity provider in the area. YEC will provide the power and the back
Utility supply voltage	V	600	
Utility supply capacity	kVA		
Main power generated onsite	yes/no	no	
Main power generators	number, type, kV, kVA	0	
Emergency/Black Start power supply	Utility/Generated	Utility	
Emergency/Black Start power generators	number, type, kV, kVA	0	
Emergency/Black Start power voltage	kV	NA	
Emergency/Black Start power capacity kV	kVA	NA	
UPS services, voltage, size and capacity	V, kVA, h	TBD	Provide UPS battery back-up for all nessecary control system hardware
Design of Distributed Control System (DCS)	manufacturer	TBD	
Control system software suppl	supplier	TBD	
Safety instrumentation system typ	type	TBD	
Instrument Air			
Compressors	type	TBD	Contractor to provide instrument air system as part of LNG Facility scope.
Drying system	type	TBD	
Flow rate	scfm	TBD	
Pressure	psig	TBD	
Plant Air			
Compressors	type	TBD	There is currently no plant to provide plant area at the LNG area. Contractor to advise if this decision should be revisted
Flow rate	scfm	TBD	
Pressure	bar		
Nitrogen			
Source		TBD	Nitrogen will be provided from cylinders
Liquid nitrogen storage capacity	liter	TBD	
Flow rate	scfm	TBD	
Pressure	bar	10	
Fire Water			
Source	mains/storage	NA	Power plant will extend fire water loop around LNG area.
Pump and driver type		NA	
Pump rated capacity	usgpm/hp/psig	NA	
Pump operating and standby		NA	
Make up water source		NA	
Make up water available flow rate	usgpm	NA	
Make up water available pressure	psig	NA	
Fire water storage type and capacity	usg	NA	
Fire water design flow rate	usgpm	NA	
Fire water supply pressure	psig	NA	
Fire water nozzle pressure	psig	NA	
Fire Protection			
Fire protection service		NA	
Site Security			
Site security service		YEC	Power plant will provide for operating plant

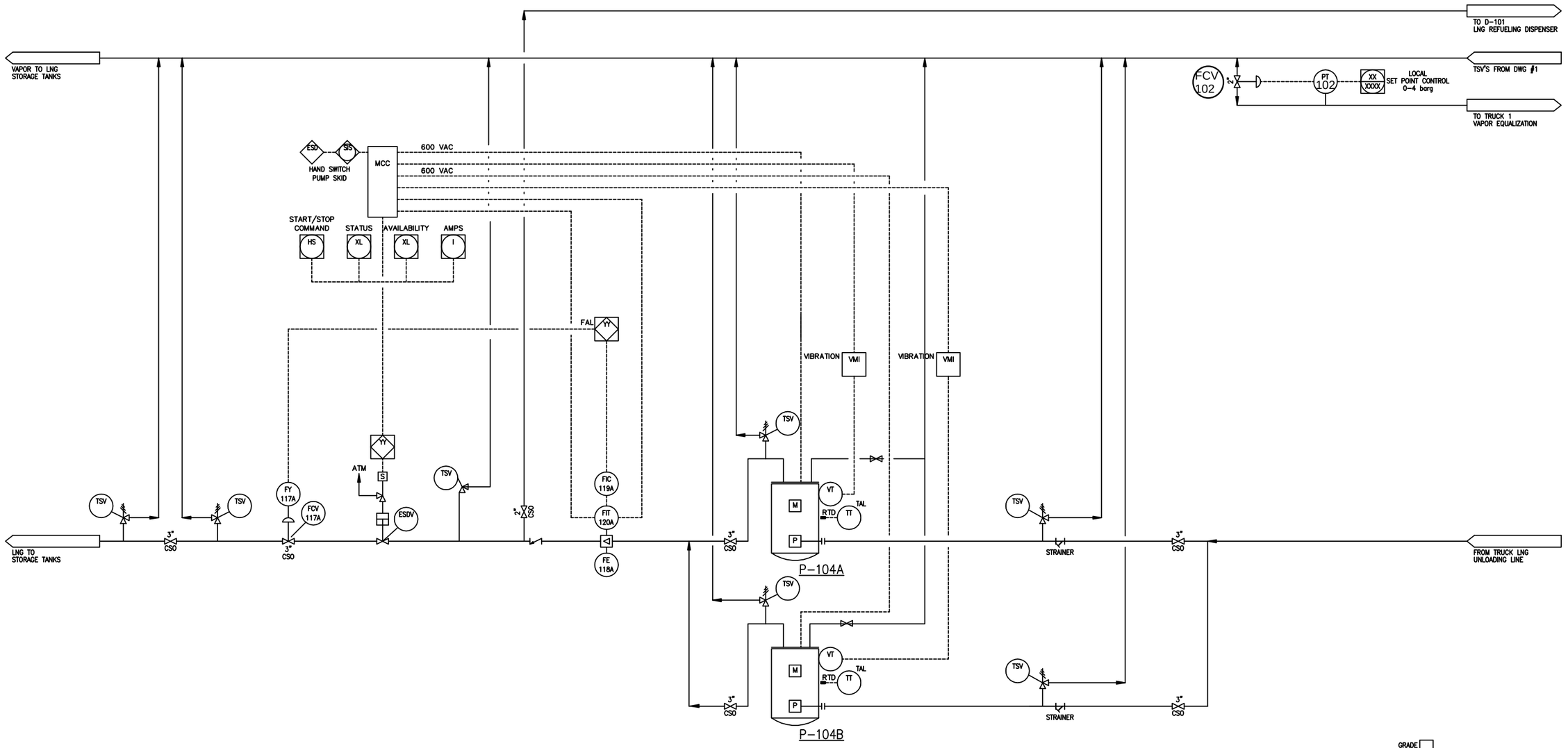
Notes: TBD - To Be Determined

NA - Not Applicable

APPENDIX E – PROCESS FLOW DIAGRAMS AND PIPING AND INSTRUMENTATION DIAGRAMS


BOG VAPOUR LINE
LNG TANK PUMP 1 P-301A
LNG TANK PUMP 2 P-301B
BOTTOM WITHDRAWL
LNG
VACUUM JACKET HORIZONTAL TANKS T-201A-F
UNLOADING PUMPS 1 & 2 P-104A/B
FLEXIM LNG FLOW METER
UNLOADING BAY UM-101
FLARE F-803
PAD GAS
PAD GAS PR-811
PRV 0.2 BARG SP
BOG COMPRESSORS C-802A/B
E-615 HEAT EXCHANGER
WARM VAPOUR
LNG TRUCK REFUELING DISPENSER D-101
TO FUEL GAS DISTRIBUTION (5.3-8.0 BARG)
E-604 HEAT EXCHANGER
WASTE HEAT LOOP FROM POWER GENERATION
WASTE HEAT LOOP TO POWER GENERATION
VP-701A/B LNG VAPORIZERS
V1
V2
TT
PI
PRESSURE CONTROL WITH TEMPERATURE OVERRIDE
SEND-OUT METER M-901
FLOW COMPUTER
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e located at
pe of the
ring tankers
from the
e unloading
ed.
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YEC – WHITEHORSE
PROCESS FLOW DIAGRAM
LNG STORAGE & RECEIVING FACILITY
DRAWN TAP
DATE 06/20/2013
dwg. no. 0

Rate	**Design/Max**	Design	Design	Design	Design	Design	Design	Design	Design	Design	Design	Design	Design	Design
		Suction	Discharge	Suction	Discharge	Inlet	Outlet	Inlet	Inlet	Inlet	Inlet	Outlet	Inlet	Outlet
		P-104A/B	**P-104A/B**	**P-301A/B**	**P-301A/B**	**E-615**	**E-615**	**F-803**	**M-901**	**D-101**	**VP-701**	**VP-701**	**E-604**	**E-604**
		2	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**
Phase	**L/G**	L	L	L	L	G	G	G	G	L	L	L	L	L
Flow Rate	**M3/HOUR**	68	68	6	6	64	64	760	523/7374	11	91	91	9	9
Pressure	**BARG**	0.09	8	0.7	8.7	6.9	6.9	6.9	18.9 max	13.8				
Temp	**C**	-163	-163	-163	-163	-163	10	-163	10/40	-163	84	69	-20	50
Density	**KG/m3**	427.6	427.6	427.6	427.6	2	0.7	2	0.7	427.6	1057	1057	1057	1057



ELEVATION VIEW (NO SCALE)

P-104A/B
LNG TRUCK UNLOADING PUMP
CENTRIFUGAL POT MOUNTED SUBMERGED PUMP & MOTOR

DESIGN CAPACITY: 70
DESIGN CAPACITY UNITS: m3/hour (LNG)
OPERATING PRESSURE [barg]: 8
ANSI CLASS: 150
DESIGN TEMP LOW [°C]: -161
DESIGN TEMP HIGH [°C]: -150
MAIN MATERIAL: SS
DESIGN CODE: TBD

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YEC – WHITEHORSE
P&ID AREA 1 TRUCK UNLOADING
PUMP SKID 1 BAY 1

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date
DRAWN TAP
DATE 07/21/2013
dwg. no. 2

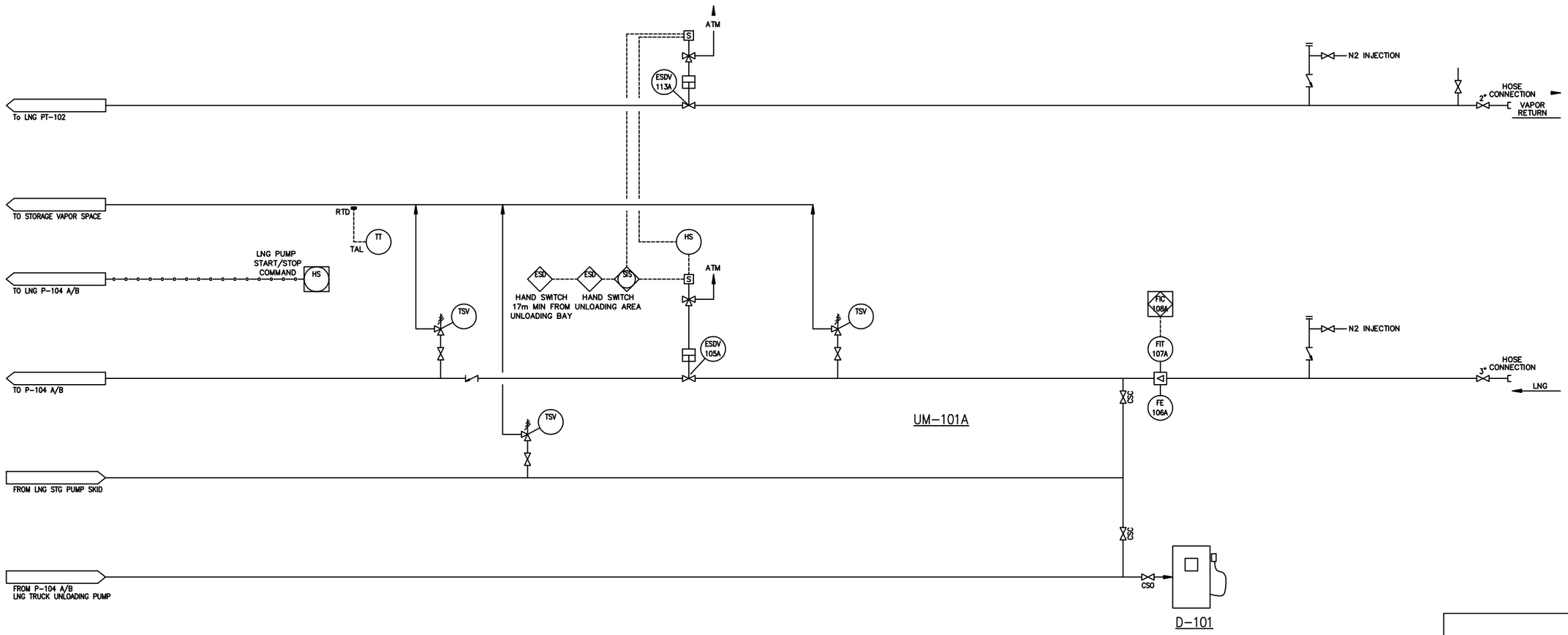
UM–101A
LNG TANKER UNLOADING MANIFOLD
MANIFOLD

DESIGN CAPACITY: 68
DESIGN CAPACITY UNITS: m3/hour (LNG)
OPERATING PRESSURE [barg]: 5.5
ANSI CLASS: 150
DESIGN TEMP LOW [°C]: –161
DESIGN TEMP HIGH [°C]: 38
MAIN MATERIAL: SS
DESIGN CODE: TBD

D–101
LNG TRUCK REFUELING
DISPENSER

DESIGN CAPACITY: 50
DESIGN CAPACITY UNITS: GPM
OPERATING PRESSURE [barg]: .
ANSI CLASS: 150
DESIGN TEMP LOW [°C]: –161
DESIGN TEMP HIGH [°C]: 35
MAIN MATERIAL: SS
DESIGN CODE: TBD

NOTE: COMBINED WITH LNG TRUCK UNLOADING PUMP SKID



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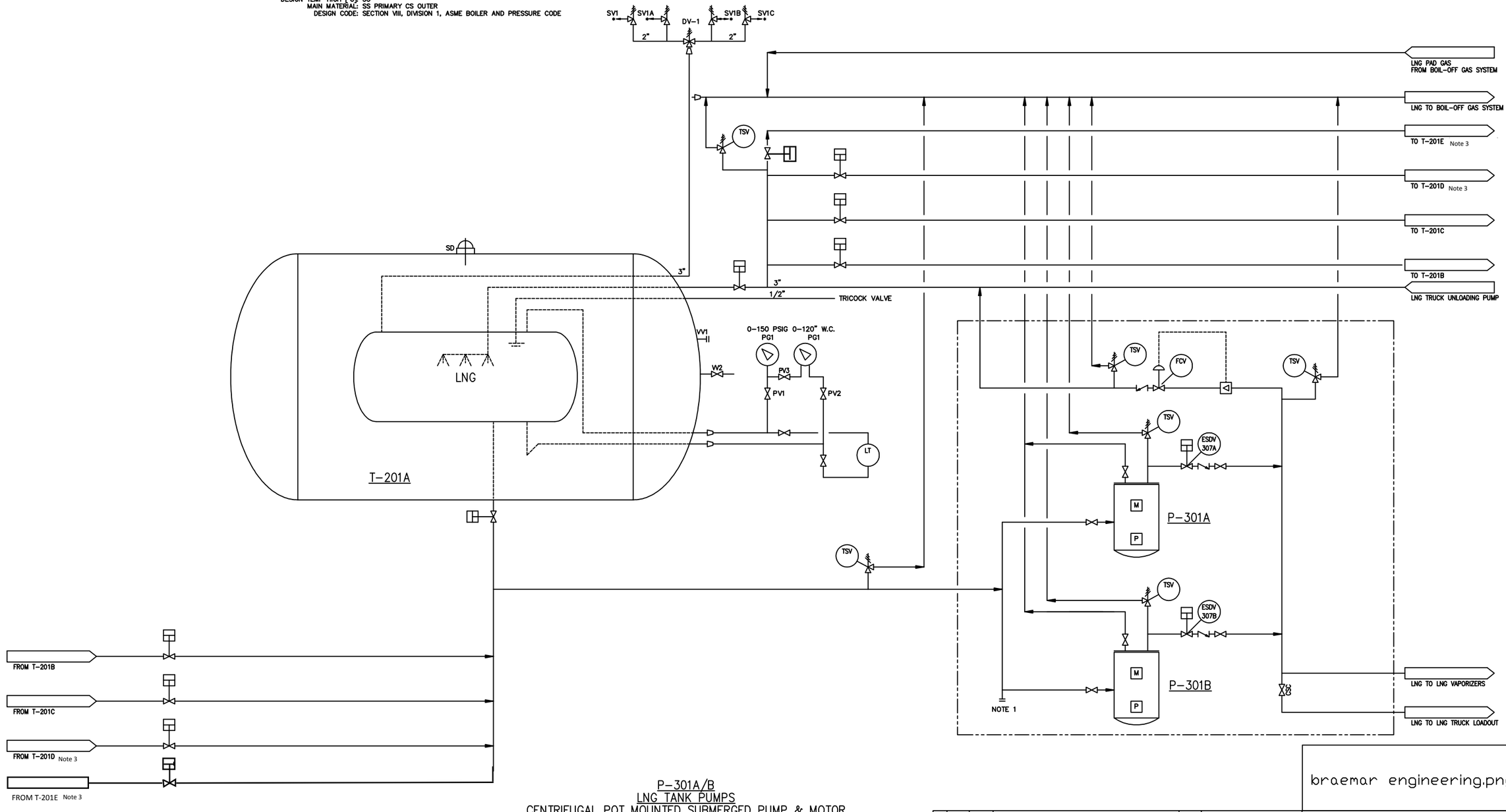
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YEC – WHITEHORSE
P&ID AREA 1 LNG TANKER
UNLOADING MANIFOLD BAY 1

scale: NONE
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DRAWN TAP
DATE 07/20/2013
dwg. noˈ

T-201A/B/C/D/E
LNG STORAGE TANK
VACCUM JACKETED, SINGLE CONTAINMENT LNG TANK NOTE 2

GROSS DESIGN CAPACITY: A/B/C= 166.5, D/E= 120
DESIGN CAPACITY UNITS: m3
OPERATING PRESSURE [barg]: 6.9
ANSI CLASS: 150
DESIGN TEMP LOW [°C]: -195
DESIGN TEMP HIGH [°C]: 35
MAIN MATERIAL: SS PRIMARY CS OUTER
DESIGN CODE: SECTION VIII, DIVISION 1, ASME BOILER AND PRESSURE CODE



P-301A/B
LNG TANK PUMPS
CENTRIFUGAL POT MOUNTED SUBMERGED PUMP & MOTOR

DESIGN CAPACITY: 6
DESIGN CAPACITY UNITS: m3/hour (LNG)
OPERATING PRESSURE [barg]: 5.3-8.0
ANSI CLASS: 150
DESIGN TEMP LOW [°C]: -161
DESIGN TEMP HIGH [°C]: -150
MAIN MATERIAL: SS
DESIGN CODE: TBD

NOTES:
(1.) PROVIDE FLANGE, ELECTRICAL AND CONTROL TIE-INS FOR FUTURE PUMP, P-301C.
(2.) LNG TANKS AND ASSOCIATED PIPING WILL BE DE-INVENTORIED EACH SUMMER.
(3.) CONTRACTOR SHALL MAKE PIPING AND CONTROL PROVISIONS TO ALLOW T-201 D/F CONVENIENTLY TIE-IN IN FUTURE.

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YEC – WHITEHORSE
P&ID AREA 2 AND 3
LNG STORAGE TANK AND PUMPS

scale: NONE
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date
DRAWN TAP
DATE 07/14/2013
dwg. no. 3

VP-701A/B
LNG VAPORISERS
VERTICAL SHELL WITH TUBE BUNDLES

DESIGN CAPACITY: 12
DESIGN CAPACITY UNITS: m3/hour
OPERATING PRESSURE [barg]: .15
ANSI CLASS: 150
DESIGN TEMP LOW [°C]: .
DESIGN TEMP HIGH [°C]: .
MAIN MATERIAL: SS
DESIGN CODE: TBD

E-604
BLACK START HEAT EXCHANGER
ELECTRIC ELEMENT HEATER

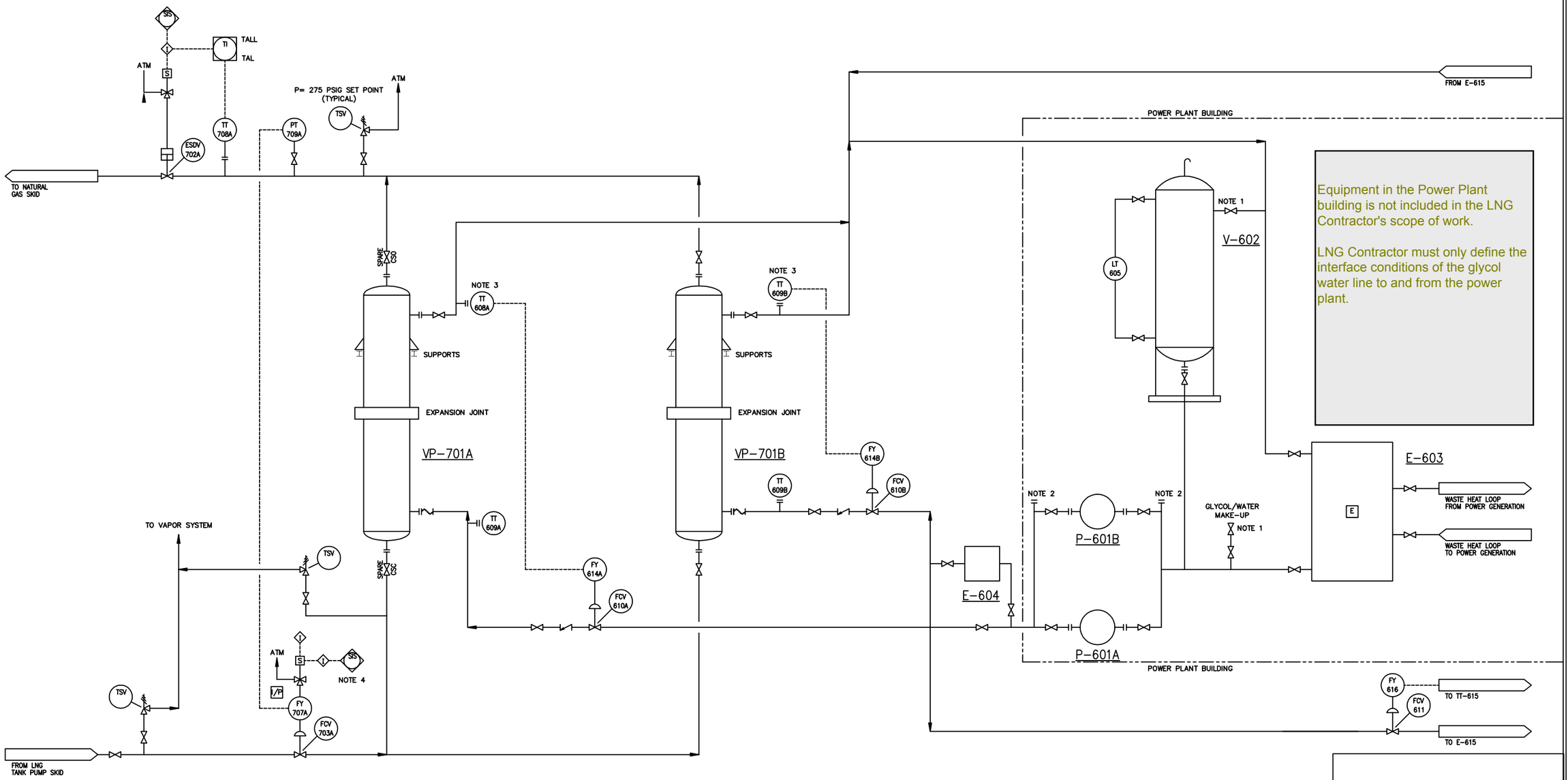
DESIGN CAPACITY: 100
DESIGN CAPACITY UNITS: KW
OPERATING PRESSURE [barg]: 8
ANSI CLASS: N/A
DESIGN TEMP LOW [°C]: -25
DESIGN TEMP HIGH [°C]: 100
MAIN MATERIAL: CS
DESIGN CODE: TBD

V-602
GLYCOL/WATER SURGE TANK
VERTICLE VESSEL

DESIGN CAPACITY: 2
DESIGN CAPACITY UNITS: m3
OPERATING PRESSURE [barg]: ATMOSPHERIC
ANSI CLASS: N/A
DESIGN TEMP LOW [°C]: -25
DESIGN TEMP HIGH [°C]: 100
MAIN MATERIAL: CS
DESIGN CODE: NONE

E-603
GLYCOL/WATER EXCHANGER
PLATE FIN

DESIGN CAPACITY: 91
DESIGN CAPACITY UNITS: m3/hour
OPERATING PRESSURE [barg]: 8
ANSI CLASS: N/A
DESIGN TEMP LOW [°C]: -25
DESIGN TEMP HIGH [°C]: 100
MAIN MATERIAL: ALUM
DESIGN CODE: TBD



P-601A/B
GLYCOL/WATER CIRCULATION PUMP
GLYCOL/WATER PUMP

DESIGN CAPACITY: 45
DESIGN CAPACITY UNITS: m3/hour
OPERATING PRESSURE [barg]: 6.9
ANSI CLASS: N/A
DESIGN TEMP LOW [°C]: -25
DESIGN TEMP HIGH [°C]: 100
MAIN MATERIAL: CS
DESIGN CODE: TBD

NOTES:
(1.) USED FOR INITIAL SYSTEM CHARGING OR MAKE-UP.
(2.) CONTRACTOR SHALL MAKE PIPING AND CONTROL PROVISIONS TO ALLOW INSTALLATION OF P-601C IN THE FUTURE.
(3.) ON STREAM VAPORIZER WILL ALLOW MAX FLOW AS LONG AS (1) E-615 IS GETTING SUFFICIENT FLOW AND (2) TT-608A AND 609B ARE BOTH ABOVE THE FREEZING POINT OF THE WATER-GLYCOL.
(4.) LNG FLOW TO VAPORIZERS WILL BE CONTROLLED TO MAINTAIN DESIRED PRESSURE TO POWER PLANT.

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YEC – WHITEHORSE
P&ID AREA 6 AND 7
GLYCOL/WATER AND LNG VAPORISERS

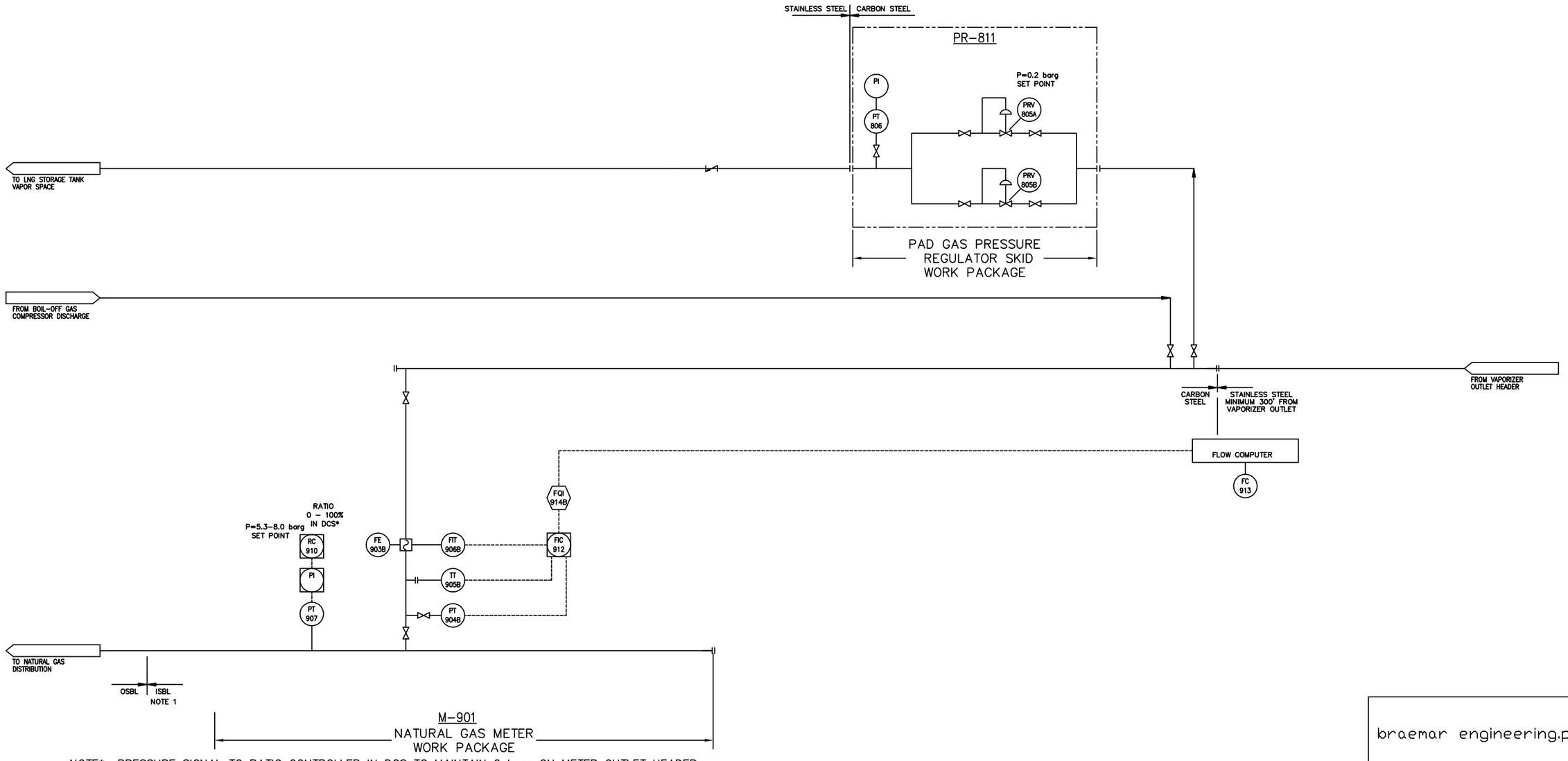
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DATE 07/21/2013
dwg. no.

M-901
SEND-OUT GAS METERING STATION
METERING STATION

DESIGN CAPACITY: 7374
DESIGN CAPACITY UNITS: m3/hour (GAS)
OPERATING PRESSURE [barg]: 5.3-8.0
ANSI CLASS: 150
DESIGN TEMP LOW [°C]: -25
DESIGN TEMP HIGH [°C]: 65
MAIN MATERIAL: CS
DESIGN CODE: TBD

PR-811
PAD GAS SKID
NATURAL GAS PRESSURE REDUCING STATION

DESIGN CAPACITY: 47.2
DESIGN CAPACITY UNITS: m3/hour
OPERATING PRESSURE [barg]: 0.2
ANSI CLASS: 150
DESIGN TEMP LOW [°C]: -25
DESIGN TEMP HIGH [°C]: 38
MAIN MATERIAL: CS
DESIGN CODE: TBD



NOTE*: PRESSURE SIGNAL TO RATIO CONTROLLER IN DCS TO MAINTAIN 6 barg ON METER OUTLET HEADER.

NOTES:
(1.) CONTRACTOR WILL TIE-IN TO UNDERGROUND LINE.

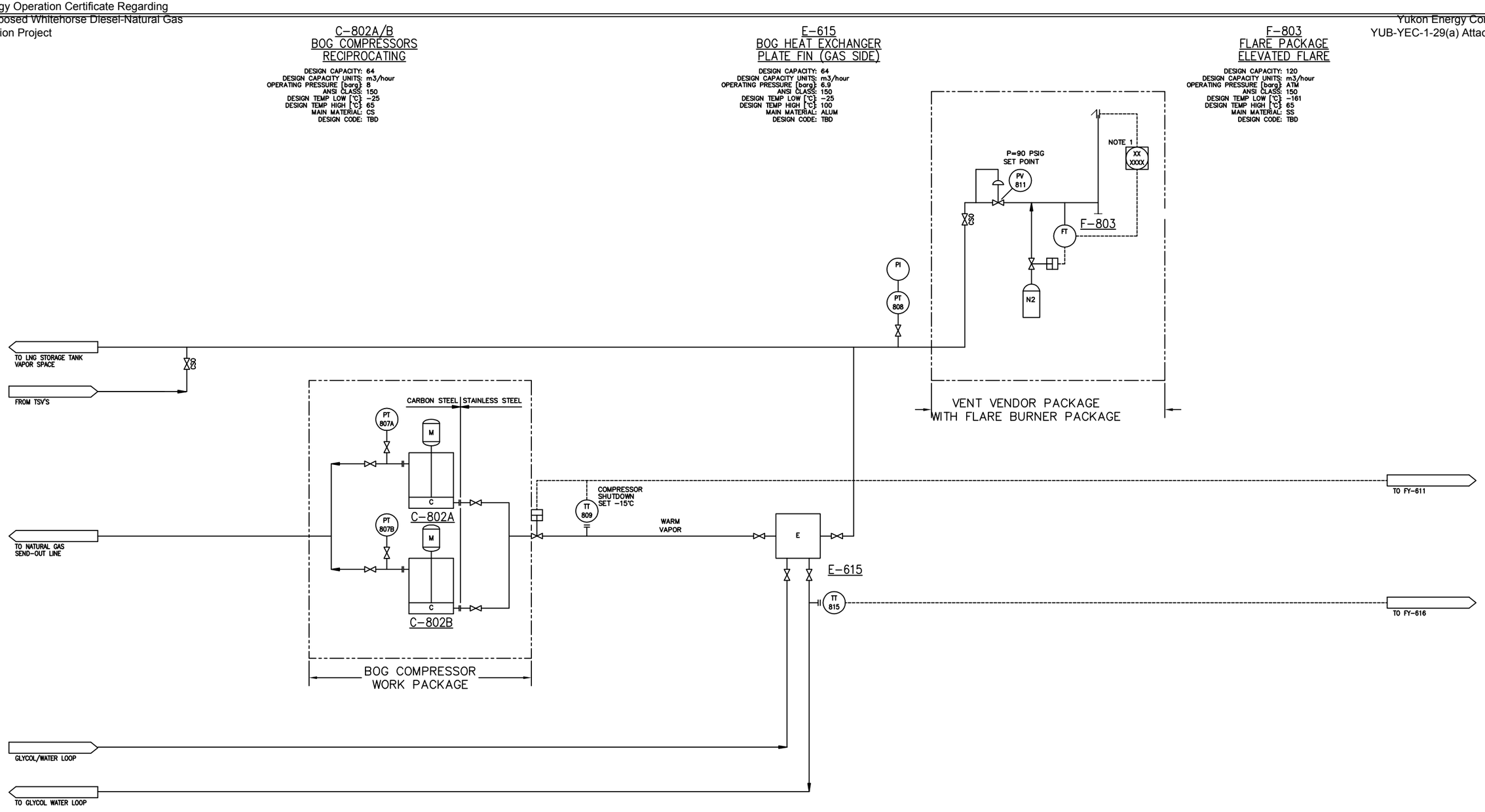
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rev	by	date	description	app'd.

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YEC - WHITEHORSE
P&ID AREA 9 NATURAL GAS SEND-OUT AND OVER PRESSURE PROTECTION

scale: NONE
app'd.
date
DRAWN TAP
DATE 07/21/2013
dwg. no. 7



NOTES:
(1.) FT SENSE FLOW AND THEN OPEN NITROGEN BOTTLE FOR (X) SECONDS TO INERT THE PIPELINE UPSTREAM OF FLARE.
AFTER (X) SECONDS THE INGNITER ON THE FLARE ACTIVATES AND NITROGEN VALVE CLOSES.

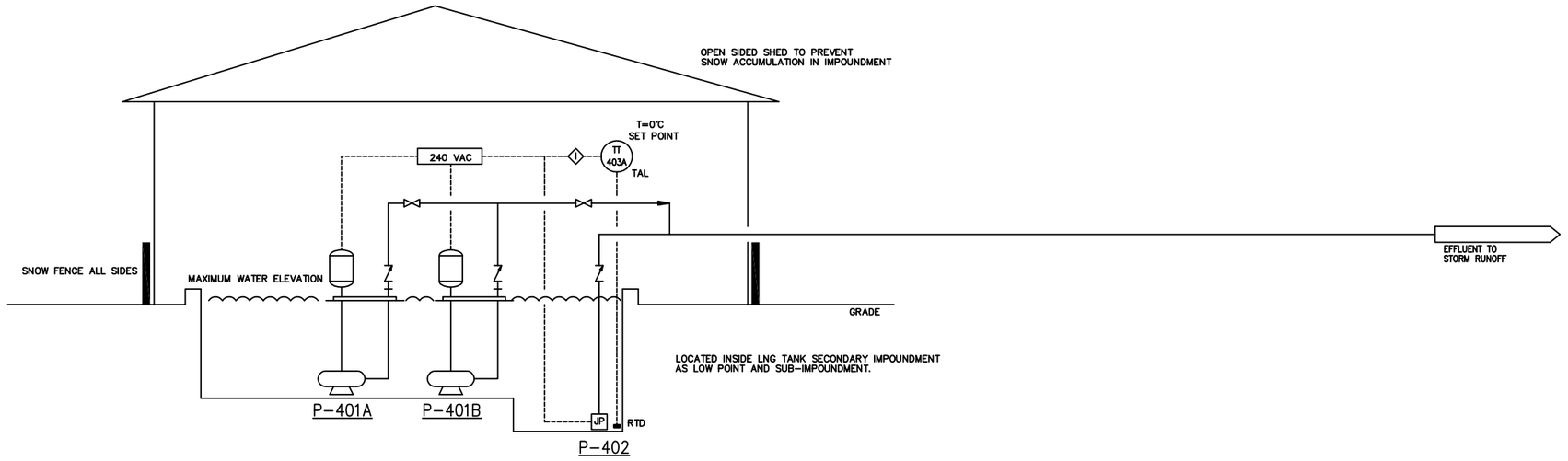
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YEC – WHITEHORSE
P&ID AREA 8
VAPOR RECOVERY AND PAD GAS

scale: NONE
DRAWN TAP
DATE 07/21/2013
app'd.
date
dwg. no. 6



EQUIPMENT:

1. P1&P2: 2 – 100% SUBMERSIBLE WATER PUMPS W/AUTO START/STOP LEVEL SWITCH, SIZED FOR 10 YEAR STORM EVENT.
   JP – MIMIMUM FLOW SUBMERSIBLE WATER JOCKEY PUMP W/AUTO START/STOP LEVEL SWITCH FOR SMALL ACCUMULATIONS OF WATER.
   LOW TEMPERATURE INTERLOCK DISABLES ALL PUMPS TO AVOID PUMPING LNG SPILL FROM IMPOUNDMENT OR ACTUATING PUMPS WHEN WATER IS FROZEN.

P-401A/B
IMPOUNDMENT STORMWATER
SUBMERSIBLE PUMPS

DESIGN CAPACITY: 9.1
DESIGN CAPACITY UNITS: m3/hour (WATER)
OPERATING PRESSURE [barg]: 3
ANSI CLASS: 150
DESIGN TEMP LOW [°C]: 0
DESIGN TEMP HIGH [°C]: 38
MAIN MATERIAL: CS
DESIGN CODE: TBD

P-402
IMPOUNDMENT STORMWATER
SUBMERSIBLE JOCKEY PUMP

DESIGN CAPACITY: 2
DESIGN CAPACITY UNITS: m3/hour (WATER)
OPERATING PRESSURE [barg]: 3
ANSI CLASS: N/A
DESIGN TEMP LOW [°C]: 0
DESIGN TEMP HIGH [°C]: 38
MAIN MATERIAL: CS
DESIGN CODE: TBD

braemar engineering.png

rev	by	date	description	app'd.

scale: NONE

app'd.
date

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YEC – WHITEHORSE
P&ID AREA 4
LNG SPILL SUB-IMPOUNDMENT

DRAWN TAP | DATE 07/14/2013

dwg. no.

APPENDIX F – DATA SHEETS

LNG TANKER UNLOADING PUMP
US and CANADA CUSTOMARY UNITS

FOR	Yukon Energy Corporation				SERVICE	**LNG Tanker Unloading Pumps**
SITE	Whitehorse, YK				EQUIPMENT #	**P-104A, P-104B**
MANUFACTURER			MODEL		TYPE	Submerged, Centrifugal
Pump Size	35 (estimated)	Hp				
OPERATING CONDITIONS						
		Unit		Unit	SERVICE	CONTINUOUS
CAPACITY EACH PUMP	68	m3/hour (LNG)	300	gpm	TYPE OR NAME OF LIQUID	LNG
TOTAL CAPACITY REQUIRED (without spare)	68	m3/hour (LNG)	300	gpm	LIQUID	FLAMMABLE
QUANTITY OF PUMPS	2	2-100% Capacity		each	MOTOR PROVIDED	Yes, with Pump
PUMPS TO OPERATE IN (PARALLEL)	Yes		SPARE PARTS	Yes, with Pump	SUCTION VESSEL PROVIDED	Yes, Vertical with Pump
PUMPING PRESSURE						
SUCTION PRESSURE MAX./RATED	0.09	barg (Min)	1.3	psig (Min)	275	psig (MAOP)
DISCHARGE PRESSURE	8	barg	116.0	psig (Max)	275	psig (MAOP)
DIFFERENTIAL PRESSURE	5.91	bar	85.7	psi		
DIFF. HEAD	141	m	464	ft		
NPSHA	<3	m	<10	ft		
DENSITY (LNG)	427.56	kg/m^3 - 163 ^0C	26.692	lb/ft^3 -261 ^0F		
PUMPING TEMPERATURE						
NORMAL OPERATING TEMPERATURE RANGE	-254	MAX (°F)	-261	MIN (°F)		
	-159	MAX (°C)	-163	MIN (°C)		
ELECTRICAL						
POWER	DRIVERS*	CONTROL			VFD	Yes, with Pump, if available
VOLTAGE	600	120				
HERTZ	60	60				
PHASE	3	1				
DESIGN RATING (LBS)						
	Connection	Rating	Type	Location	MAOP	Unit
SUCTION		150# ANSI	RF	Side	275	psi
DISCHARGE		150# ANSI	RF	Top	275	psi
VAPOUR		150# ANSI	RF	Vent	275	psi
MATERIAL OF CONSTRUCTION - PUMP	Stainless Steel				MATERIAL OF CONSTRUCTION - SUCTION VESSEL	Stainless Steel
LOCATION						
OUTDOOR	Yes				Seismic	** See note below
UNDER ROOF	Yes				Wind (kph)	201
PARTIAL SIDES	Yes					
AT GRADE	Yes					
HEATED	No					
AMBIENT TEMPERATURE RANGE	104	MAX (°F)	-67	MIN (°F)		
	40	MAX (°C)	-55	MIN (°C)		
QA INSPECTION - TESTING						
HYDROTEST	Yes		PUMP CURVE	Yes		
NONDESTRUCTIVE TEST	Vendor to Submit Procedure					

**See: http://www.earthquakescanada.nrcan.gc.ca/hazard-alea/interpolat/index_2010-eng.php Use Site Coordinates: 60.6958 North 135.0469 West

LNG STORAGE TANK

US and CANADA CUSTOMARY UNITS

FOR	Yukon Energy Corporation				SERVICE	**LNG STORAGE TANK**
SITE	Whitehorse, YK				EQUIPMENT #	**T-201 A,B,C**
MANUFACTURER				TYPE	Shop fabricated horizontal VJ tanks @ 90% full	
TYPE OR NAME OF LIQUID	LNG		Design Code: ASME Section VIII, Division 1			
OPERATING CONDITIONS						
		Unit		Unit	SERVICE	
GROSS CAPACITY PER TANK	188.0	m3				
NET CAPACITY PER TANK AT 90% FULL	166.5	m3				
QUANTITY OF LNG TANKS	3	each				
DENSITY (LNG)	470.00	kg/m^3 - 163 ^0C			Per CSA Z276	
NORMAL OPERATING TEMPERATURE RANGE	Ambient	MAX (°F)	-261	MIN (°F)	Tanks may be emptied annually	
	Ambient	MAX (°C)	-163	MIN (°C)		
MECHANICAL REQUIREMENTS						
TANK DIAMETER (OUTER)	3.8	m	12.5	feet		
TANK LENGTH (OUTER)	21.3	m	70.0	feet		
OUTER TANK HEIGHT	7.8	m	13.0	feet		
MAOP PRESSURE	0	PSIG (Min)	100	PSIG (Max)		
MATERIAL OF CONSTRUCTION - INNER	304 SS				MATERIAL OF CONSTRUCTION - OUTER	CARBON STEEL
THERMAL INSULATION	Vacuum jacketed					
CONNECTION SIZES AND DESIGN	See Nozzle Schedule					
LOCATION						
OUTDOOR	Yes				Seismic	** See note below
UNDER ROOF	No				Wind (kph)	201
PARTIAL SIDES	No					
AT GRADE	Yes					
AMBIENT TEMPERATURE RANGE	104	MAX (°F)	-67	MIN (°F)		
	40	MAX (°C)	-55	MIN (°C)		
QA INSPECTION - TESTING						
HYDROTEST	Yes, to CSA Z-276					
NONDESTRUCTIVE TEST	Vendor to Submit Procedure for Compliance to CSA Z276					

**See: http://www.earthquakescanada.nrcan.gc.ca/hazard-alea/interpolat/index_2010-eng.php
Use Site Coordinates: 60.6958 North 135.0469 West

External LNG Tank Nozzle Schedule

No.	Service	Size (inches)	Size (cm)	Qty	Rating	
N1	Top Fill	TBD	3"	1	150#	
N2	Vapour System	TBD	3"	1	150#	
N3	Bottom Withdrawal	TBD	2"	1	150#	Basis of vapor dispersion model
N4	Tricock valve	TBD	1/2"	1	150#	
N5	Level Transmitter	TBD		1	150#	two independent lever gauges required per CSA-Z276
N6	Level Transmitter	TBD		1	150#	
N7	misc nozzels required/suggested by tank vendor					

(FUTURE) LNG STORAGE TANK

US and CANADA CUSTOMARY UNITS

FOR	Yukon Energy Corporation				SERVICE	**LNG STORAGE TANK**
SITE	Whitehorse, YK				EQUIPMENT #	**T-201 D, E**
MANUFACTURER				TYPE	Shop fabricated horizontal VJ tanks @ 90% full	
TYPE OR NAME OF LIQUID	LNG		Design Code: ASME Section VIII, Division 1			
OPERATING CONDITIONS						
		Unit		Unit	SERVICE	
GROSS CAPACITY PER TANK	133	m3				
NET CAPACITY PER TANK AT 90% FULL	120	m3				
QUANTITY OF LNG TANKS	2	each				
DENSITY (LNG)	470.00	kg/m^3 - 163 ^{0}C			Per CSA Z276	
NORMAL OPERATING TEMPERATURE RANGE	Ambient	MAX (°F)	-261	MIN (°F)	Tanks may be emptied annually	
	Ambient	MAX (°C)	-163	MIN (°C)		
MECHANICAL REQUIREMENTS						
TANK DIAMETER (OUTER)	3.8	m	12.5	feet		
TANK LENGTH (OUTER)	21.3	m	70.0	feet		
OUTER TANK HEIGHT	7.8	m	13.0	feet		
MAOP PRESSURE	0	PSIG (Min)	100	PSIG (Max)		
MATERIAL OF CONSTRUCTION - INNER	304 SS				MATERIAL OF CONSTRUCTION - OUTER	CARBON STEEL
THERMAL INSULATION	Vacuum jacketed					
CONNECTION SIZES AND DESIGN	See Nozzle Schedule					
LOCATION						
OUTDOOR	Yes				Seismic	** See note below
UNDER ROOF	No				Wind (kph)	201
PARTIAL SIDES	No					
AT GRADE	Yes					
AMBIENT TEMPERATURE RANGE	104	MAX (°F)	-67	MIN (°F)		
	40	MAX (°C)	-55	MIN (°C)		
QA INSPECTION - TESTING						
HYDROTEST	Yes, to CSA Z-276					
NONDESTRUCTIVE TEST	Vendor to Submit Procedure for Compliance to CSA Z276					

**See: http://www.earthquakescanada.nrcan.gc.ca/hazard-alea/interpolat/index_2010-eng.php
Use Site Coordinates: 60.6958 North 135.0469 West

External LNG Tank Nozzle Schedule

No.	Service	Size (inches)	Size (cm)	Qty	Rating	
N1	Top Fill	TBD	3"	1	150#	
N2	Vapour System	TBD	3"	1	150#	
N3	Bottom Withdrawal	TBD	2"	1	150#	Basis of vapor dispersion model
N4	Tricock valve	TBD	1/2"	1	150#	
N5	Level Transmitter	TBD		1	150#	two independent lever gauges required per CSA-Z276
N6	Level Transmitter	TBD		1	150#	
N7	misc nozzels required/suggested by tank vendor					

LNG TANK PUMP

US and CANADA CUSTOMARY UNITS

FOR	Yukon Energy Corporation				SERVICE	**LNG Tank Pumps**
SITE	Whitehorse, YK				EQUIPMENT #	**P-301A, P-301B**
MANUFACTURER			MODEL		TYPE	Centrifugal
Pump Size	15 (estimated)	Hp				
OPERATING CONDITIONS						
		Unit		Unit	SERVICE	CONTINUOUS
CAPACITY EACH PUMP	6	m3/hour (LNG)	26	gpm	TYPE OR NAME OF LIQUID	LNG
TOTAL CAPACITY REQUIRED (Phase 1)	6	m3/hour (LNG)	26	gpm	LIQUID	FLAMMABLE
QUANTITY OF PUMPS (2 with original construction. Future pump will not be purchased by original contractor)	2	2-50% Capacity		each	MOTOR PROVIDED	Yes, with Pump
FUTURE PUMP	Original Contractor to provide a foundation for one future LNG pump and piping and electrical connection to facilitate installation in 5-10 years.					
PUMPS TO OPERATE IN (PARALLEL)	Yes		SPARE PARTS	Yes, with Pump	SUCTION VESSEL PROVIDED	Yes, Vertical with Pump
PUMPING PRESSURE						
DIFFERENTIAL PRESSURE	8.0	barg	116.0	psig	275	psig (MAOP)
DIFF. HEAD	198	m	650	ft		
NPSHA	<1.5	m	<4	ft		
DENSITY (LNG)	427.56	kg/m^3 -163 ^{0}C	26.692	lb/ft^3 -261 ^{0}F		
PUMPING TEMPERATURE						
NORMAL OPERATING TEMPERATURE RANGE	-254	MAX (°F)	-261	MIN (°F)		
	-159	MAX (°C)	-163	MIN (°C)		
ELECTRICAL						
POWER	DRIVERS*	CONTROL			VFD	Yes, with Pump
VOLTAGE	600	120				
HERTZ	60	60				
PHASE	3	1				
DESIGN RATING (LBS)						
	Connection	Rating	Type	Location	MAOP	Unit
SUCTION	TBD	150# ANSI	RF	Side	275	psi
DISCHARGE	TBD	150# ANSI	RF	Top	275	psi
VAPOUR	TBD	150# ANSI	RF	Vent	275	psi
MATERIAL OF CONSTRUCTION - PUMP	Stainless Steel				MATERIAL OF CONSTRUCTION - SUCTION VESSEL	Stainless Steel
LOCATION						
OUTDOOR	Yes				Seismic	** See note below
UNDER ROOF	Yes				Wind (kph)	201
PARTIAL SIDES	Yes					
AT GRADE	Yes					
HEATED	No					
AMBIENT TEMPERATURE RANGE	104	MAX (°F)	-67	MIN (°F)		
	40	MAX (°C)	-55	MIN (°C)		
QA INSPECTION - TESTING						
HYDROTEST	Yes		PUMP CURVE	Yes		
NONDESTRUCTIVE TEST	Vendor to Submit Procedure					

**See: http://www.earthquakescanada.nrcan.gc.ca/hazard-alea/interpolat/index_2010-eng.php
Use Site Coordinates: 60.6958 North 135.0469 West

BLACK START HEAT EXCHANGER

US and CANADA CUSTOMARY UNITS

FOR	Yukon Energy Corporation				SERVICE	**Black Start Heat Exchanger**
SITE	Whitehorse, YK				EQUIPMENT #	**E-604**
MANUFACTURER			MODEL		TYPE	Aluminum Plate Fin Exchanger
TYPE OR NAME OF LIQUID	HEAT TRANSFER FLUID	50:50 Ethylene Glycol and Water				
OPERATING CONDITIONS						
		Unit		Unit	SERVICE	CONTINUOUS
FLOWRATE OF PROCESS HEAT TRANSFER FLUID	9	m^3/hour (liquid)	40.0	gpm	water/glycol flowrate will be controlled to regulate temperature of water/glycol to vaporizer.*	
QUANTITY OF HEAT EXCHANGERS REQUIRED	1	1 - 100% Capacity		each		
DENSITY 50:50 Ethylene Glycol and Water	1056.75	kg/m^3 0 ^0C	65.96	lb/ft^3 32 ^0F		
Power requirement of black start generator (kW)	100	kW			Energy required to vaporize and heat to ~20C the amount of LNG required to fuel 2.2 MW of generation, i.e., 0.85 m3/hr of LNG.	
PROCESS GLYCOL WATER TEMPERATURE	Inlet		-20	(°C)		
	Outlet		50	(°C)		
MECHANICAL REQUIREMENTS						
DESIGN CODE	ASME VIII					
DESIGN PRESSURE	0	barg (Min)	0	psig (Min)	TBD	psig (Max)
MATERIAL OF CONSTRUCTION - VESSEL	Aluminum					
INTERNAL CLADDING/COATING	No				EXTERNAL COATING	for external corrosion
THERMAL INSULATION	By Others					
CONNECTION SIZES AND DESIGN RATING (LBS)						
	Connection	Rating	Type		MAOP	Unit
WASTE HEAT GLYCOL WATER INLET	TBD	ANSI 150	RF		116	psig (Max)
WASTE HEAT GLYCOL WATER OUTLET	TBD	ANSI 150	RF		116	psig (Max)
PROCESS GLYCOL WATER INLET	TBD	ANSI 150	RF		116	psig (Max)
PROCESS GLYCOL WATER OUTLET	TBD	ANSI 150	RF		116	psig (Max)
LOCATION						
OUTDOOR	Yes				Seismic	** See note below
UNDER ROOF	Yes				Wind (kph)	201
PARTIAL SIDES	Yes					
AT GRADE	Yes					
HEATED	No				Freeze Protection Required When Idle	
AMBIENT TEMPERATURE RANGE	104	MAX (°F)	-67	MIN (°F)		
	40	MAX (°C)	-55	MIN (°C)		
QA INSPECTION - TESTING						
HYDROTEST	Yes					
NONDESTRUCTIVE TEST	Vendor to Submit Procedure					

*Operating conditions correspond to vaporizing 0.85 m3/hour of LNG to produce 522 m3/hour of natgas, enough to generate 2.2 MW of electricity.
**See: http://www.earthquakescanada.nrcan.gc.ca/hazard-alea/interpolat/index_2010-eng.php Use Site Coordinates: 60.6958 North 135.0469 West

LNG VAPORIZER

US and CANADA CUSTOMARY UNITS

FOR	Yukon Energy Corporation				SERVICE	**LNG Vaporizer**
SITE	Whitehorse, YK				EQUIPMENT #	**VP-701A, VP-701B**
MANUFACTURER			MODEL		TYPE	Shell & Tube Exchanger
TYPE OR NAME OF LIQUID	HEAT TRANSFER FLUID	50:50 Ethylene Glycol and Water		PROCESS FLUID	LNG	
OPERATING CONDITIONS						
		Unit		Unit	SERVICE	
FLOWRATE OF LNG TO VAPORIZER	12	m^3/hour (LNG)	53	gpm	LNG Inlet With Phase Transition to Natural Gas	
FLOWRATE OF NATURAL GAS FROM VAPORIZER	7,374	m^3/hour (gas)	6,247	SMCFD		
FLOWRATE OF RTHYLENE GLYCOL-WATER HEAT TRANSFER FLUID	91.0	m^3/hour (liquid)	400	gpm	Based on 17 oC temperature differential	
QUANTITY OF HEAT VAPORIZERS REQUIRED	2	2 - 100% Capacity		each		
DENSITY OF LNG INLET	428.596	Density kg/m3	26.960	lb/ft^3		
DENSITY 50:50 Ethylene Glycol and Water	1056.75	kg/m^3 0 ^0C	65.96	lb/ft^3 32 ^0F		
LNG INLET TEMPERATURE	Inlet		-160	(°C)		
	Outlet		10	(°C)		
GLYCOL WATER TEMPERATURE INLET	Inlet		84	(°C)		
	Outlet		69	(°C)		
MECHANICAL REQUIREMENTS						
DESIGN CODE	ASME VIII					
DESIGN PRESSURE	Full Vacuum	barg (Min)	Full Vacuum	psig (Min)	145	psig (Max)
MATERIAL OF CONSTRUCTION - VESSEL	Stainless Steel				MATERIAL OF CONSTRUCTION - INTERNALS	Stainless Steel
INTERNAL CLADDING/COATING	No				EXTERNAL COATING	No
THERMAL INSULATION	By Others - Not Required					
CONNECTION SIZES AND DESIGN RATING (LBS)						
	Connection	Rating	Type		MAOP	Unit
GLYCOL WATER INLET	TBD	ANSI 150	RF		275	psig (Max)
GLYCOL WATER OUTLET	TBD	ANSI 150	RF		275	psig (Max)
LNG INLET	TBD	ANSI 150	RF		275	psig (Max)
NATURAL GAS OUTLET	TBD	ANSI 150	RF		275	psig (Max)
LOCATION						
OUTDOOR	Yes				Seismic	** See note below
UNDER ROOF	No				Wind (kph)	201
PARTIAL SIDES	No					
AT GRADE	Yes					
HEATED	No				Freeze Protection Required When Idle	
AMBIENT TEMPERATURE RANGE	104	MAX (°F)	-67	MIN (°F)		
	40	MAX (°C)	-55	MIN (°C)		
QA INSPECTION - TESTING						
HYDROTEST	Yes					
NONDESTRUCTIVE TEST	Vendor to Submit Procedure					

**See: http://www.earthquakescanada.nrcan.gc.ca/hazard-alea/interpolat/index_2010-eng.php Use Site Coordinates: 60.6958 North 135.0469 West

GLYCOL/WATER - BOG HEAT EXCHANGER

US and CANADA CUSTOMARY UNITS

FOR	Yukon Energy Corporation				SERVICE	**Glycol/Water-BOG Heat Exchanger**
SITE	Whitehorse, YK				EQUIPMENT #	**E-615**
MANUFACTURER			MODEL		TYPE	Aluminum Plate Fin Exchanger
TYPE OR NAME OF LIQUID	HEAT TRANSFER FLUID	50:50 Ethylene Glycol and Water		PROCESS FLUID	Cold Natural Gas (LNG Vapour)	
OPERATING CONDITIONS						
		Unit		Unit	SERVICE	
FLOWRATE OF PROCESS NATURAL GAS	64	m^3/hour (gas)	54	SMCFD	BOG Compressor Inlet Gas Heating (to protect carbon steel BOG compressor from cryogenic temperature exposure)	
FLOWRATE OF ETHYLENE GLYCOL-WATER HEAT TRANSFER FLUID	0.23	m^3/hour (liquid)	1	gpm	Based on 17 C temperature differential	
QUANTITY OF HEAT EXCHANGERS REQUIRED	1	1 - 100% Capacity		each		
DENSITY OF LNG INLET VAPOUR	0.697	Vapor Density kg/m3	0.044	lb/ft^3		
DENSITY 50:50 Ethylene Glycol and Water	1056.75	kg/m^3 $0\ ^0C$	65.96	lb/ft^3 $32\ ^0F$		
LNG VAPOUR INLET TEMPERATURE	104	MAX (°F)	-260	MIN (°F)		
	40	MAX (°C)	-163	MIN (°C)		
GLYCOL WATER TEMPERATURE	212	MAX (°F)	-13	MIN (°F)		
	100	MAX (°C)	-25	MIN (°C)		
MECHANICAL REQUIREMENTS						
DESIGN CODE	ASME VIII					
DESIGN PRESSURE	0	barg (Min)	6.9	psig (Max)		
MATERIAL OF CONSTRUCTION - VESSEL	Aluminum					
INTERNAL CLADDING/COATING	Yes, glycol water side for corrosion protection				EXTERNAL COATING	Painted for external corrosion
THERMAL INSULATION	By Others - Not Required					
CONNECTION SIZES AND DESIGN RATING (LBS)						
	Connection	Rating	Type		MAOP	Unit
GLYCOL WATER INLET	TBD	ANSI 150	NPT		275	psig (Max)
GLYCOL WATER OUTLET	TBD	ANSI 150	NPT		275	psig (Max)
GAS INLET	TBD	ANSI 150	RF		275	psig (Max)
GAS OUTLET	TBD	ANSI 150	RF		275	psig (Max)
LOCATION						
OUTDOOR	Yes				Seismic	** See note below
UNDER ROOF	Yes				Wind (kph)	201
AT GRADE	Yes					
HEATED					Freeze Protection Required When Idle	
AMBIENT TEMPERATURE RANGE	104	MAX (°F)	-67	MIN (°F)		
	40	MAX (°C)	-55	MIN (°C)		
QA INSPECTION - TESTING						
HYDROTEST	Yes					
NONDESTRUCTIVE TEST	Vendor to Submit Procedure					

**See: http://www.earthquakescanada.nrcan.gc.ca/hazard-alea/interpolat/index_2010-eng.php Use Site Coordinates: 60.6958 North 135.0469 West

BOIL-OFF GAS COMPRESSOR

US and CANADA CUSTOMARY UNITS

FOR	Yukon Energy Corporation				SERVICE	**BOG COMPRESSOR**
SITE	Whitehorse, YK				EQUIPMENT #	**C-802A, C-802B**
MANUFACTURER			MODEL		TYPE	Reciprocating
Compressor Size	TBD	Hp				
OPERATING CONDITIONS						
		Unit		Unit	SERVICE	CONTINUOUS
CAPACITY EACH COMPRESSOR	64	m3/hour (gas)	54	SMCFD (gas)	TYPE OR NAME OF FLUID	LNG Vapour
TOTAL CAPACITY REQUIRED	64	m3/hour (gas)	54	SMCFD (gas)	GAS	Flammable
QUANTITY OF COMPRESSORS	2	2-100% Capacity		each	MOTOR PROVIDED	Yes, with Compressor
COMPRESSORS TO OPERATE IN (PARALLEL)	YES		SPARE PARTS	Yes, with Compressor		
PUMPING PRESSURE						
SUCTION PRESSURE	0.7	barg	10	psig (Min)	275	psig (Max)
DISCHARGE PRESSURE	8	barg	116	psig (Min)	275	psig (Max)
DENSITY OF NATURAL GAS (standard conditions)	0.697	Vapor Density kg/m3	0.044	lb/ft^3		
COMPRESSION INLET TEMPERATURE						
VAPOUR INLET TEMPERATURE	85	MAX (°F)	40	MIN (°F)		
	29.4	MAX (°C)	4.5	MIN (°C)		
ELECTRICAL						
POWER	DRIVERS*	CONTROL			VFD	Yes, with Compressor. If available
VOLTAGE	600	120				
HERTZ	60	60				
PHASE	3	1				
DESIGN RATING (LBS)						
	Connection	Rating	Type		MAOP	Unit
SUCTION	TBD	150# ANSI	RF		275	psig (Max)
DISCHARGE	TBD	150# ANSI	RF		275	psig (Max)
LOCATION						
OUTDOOR	Yes				Seismic	** See note below
UNDER ROOF[1]	Yes				Wind (kph)	201
PARTIAL SIDES[1]	Yes					
AT GRADE[1]	Yes					
HEATED	No					
AMBIENT TEMPERATURE RANGE	104	MAX (°F)	-67	MIN (°F)		
	40	MAX (°C)	-55	MIN (°C)		
QA INSPECTION - TESTING						
NONDESTRUCTIVE TEST	Vendor to Submit Procedure					

Compressors will be located in a Class 1, Group D, Division 2 area as defined in NFPA 59A

**See: http://www.earthquakescanada.nrcan.gc.ca/hazard-alea/interpolat/index_2010-eng.php Use Site Coordinates: 60.6958 North 135.0469 West

[1]The BOG compressor enclosure and foundation pad must be construction so that any oil leakage cannot be washed away with storm water.

PAD GAS SKID

US and CANADA CUSTOMARY UNITS

FOR	Yukon Energy Corporation				SERVICE	**PAD GAS SKID**
SITE	Whitehorse, YK				EQUIPMENT #	**PR-811**
MANUFACTURER			MODEL		TYPE	Shop Fabricated Pressure Reducing Skid from Components
OPERATING CONDITIONS						
		Unit		Unit	SERVICE	INTERMITTENT
FLOW CAPACITY	47.2	m^3/hour (gas)	40	SMCFD (gas)	TYPE OR NAME OF LIQUID	Natural Gas
QUANTITY OF PAD GAS SKIDS	1	each			VAPOUR	FLAMMABLE
QUANTITY OF PARALLEL RUNS	2	1-100% Capacity		each		
			SPARE PARTS	Yes, with skid		
UNLOADING PRESSURE						
INLET PRESSURE MIN./RATED	8.3	barg (Min)	120.4	psig (Min)	275	psig (Max)
OUTLET SET PRESSURE	0.2	bar	2.9	psi	275	psig (Max)
MATERIAL OF CONSTRUCTION - MANIFOLD & COMPONENTS	Carbon Steel				MATERIAL OF CONSTRUCTION - SUPPORTS	Carbon Steel - Skid Mounted
DENSITY OF NATURAL GAS (standard conditions)	0.697	Vapor Density kg/m3	0.044	lb/ft^3		
OPERATING TEMPERATURE						
NORMAL OPERATING TEMPERATURE RANGE	100	MAX (°F)	-13	MIN (°F)		
	38	MAX (°C)	-25	MIN (°C)		
DESIGN RATING (LBS)						
	Connection	Rating	Type		MAOP	Unit
INLET FLANGE	2	ANSI 150	RF		275	psi
OUTLET FLANGE	2	ANSI 150	RF		275	psi
LOCATION						
OUTDOOR	Yes				Seismic	** See note below
UNDER ROOF	No				Wind (kph)	201
PARTIAL SIDES	No					
AT GRADE	Yes					
HEATED	No					
AMBIENT TEMPERATURE RANGE	104	MAX (°F)	-67	MIN (°F)		
	40	MAX (°C)	-55	MIN (°C)		
QA INSPECTION - TESTING						
HYDROTEST	Yes					
NONDESTRUCTIVE TEST	Vendor to Submit Procedure					

**See: http://www.earthquakescanada.nrcan.gc.ca/hazard-alea/interpolat/index_2010-eng.php
Use Site Coordinates: 60.6958 North 135.0469 West

UNLTRASONIC SEND-OUT GAS METERING STATION

US and CANADA CUSTOMARY UNITS

FOR	Yukon Energy Corporation				SERVICE	**Ultrasonic Send-out Gas Metering Station**
SITE	Whitehorse, YK				EQUIPMENT #	**M-901**
MANUFACTURER			MODEL		TYPE	Shop Fabricated Natural Gas Ultrasonic Meter Station Skid from Components
DESIGN STANDARD	AGA 9					
OPERATING CONDITIONS						
		Unit		Unit	SERVICE	CONTINUOUS
FLOW CAPACITY	7,374	m3/hour (gas)	6,247	SMCFD	110% capacity = 28.6 MW*1.1@40% efficiency	Natural Gas
MINIMUM FLOWRATE TO BE MEASURED	519	m3/hour (gas)	440	SMCFD	minimum flowrate =2.2 MW@40% efficiency	
QUANTITY OF SEND-OUT GAS METER STATIONS	1	each			VAPOUR	FLAMMABLE
QUANTITY OF PARALLEL RUNS	1	1-110% Capacity		each		
			SPARE PARTS	Yes, with skid		
OPERATING PRESSURE						
PRESSURE MIN. OPERATING	5.3	barg (Min)	77	psig (Min)	275	psig (Max)
PRESSURE MAX. OPERATING	8	barg (Min)	116	psig (Min)	275	psig (Max)
MATERIAL OF CONSTRUCTION & COMPONENTS	Carbon Steel				MATERIAL OF CONSTRUCTION - SUPPORTS	Carbon Steel - Skid Mounted
DENSITY OF NATURAL GAS (standard conditions)	0.697	Vapor Density kg/m3	0.044	lb/ft^3		
OPERATING TEMPERATURE						
NORMAL OPERATING TEMPERATURE RANGE	104	MAX (°F)	-67	MIN (°F)		
	40	MAX (°C)	-55	MIN (°C)		
DESIGN RATING (LBS)						
	Connection	Rating	Type		MAOP	Unit
INLET FLANGE*	TBD	ANSI 300	RF		720	psi
OUTLET FLANGE*	TBD	ANSI 300	RF		720	psi
LOCATION						
OUTDOOR	Yes				Seismic	
UNDER ROOF	No				Wind (kph)	201
PARTIAL SIDES	No					
AT GRADE	Yes					
HEATED	Per manufacturers specs				Insulated	
AMBIENT TEMPERATURE RANGE	104	MAX (°F)	-67	MIN (°F)		
	40	MAX (°C)	-55	MIN (°C)		
QA INSPECTION - TESTING						
HYDROTEST	Yes					
NONDESTRUCTIVE TEST	Vendor to Submit Procedure					

*ANSI 150 flanges are acceptable, if available

**See: http://www.earthquakescanada.nrcan.gc.ca/hazard-alea/interpolat/index_2010-eng.php

Use Site Coordinates: 60.6958 North 135.0469 West

IMPOUNDEMENT SUBMERSIBLE WATER PUMP

US and CANADA CUSTOMARY UNITS

FOR	Yukon Energy Corporation				SERVICE	**Impoundment Submersible Water Pump**
SITE	Whitehorse, YK				EQUIPMENT #	**P-401A, P-401B**
MANUFACTURER			MODEL		TYPE	Submersible, Centrifugal
Pump Size	2	Hp				
OPERATING CONDITIONS						
		Unit		Unit	SERVICE	INTERMITTENT
CAPACITY EACH PUMP[2]	5.7	m3/hour (Stormwater)	25.0	gpm	TYPE OR NAME OF LIQUID	Stormwater
TOTAL CAPACITY REQUIRED (without spare)	11.4	m3/hour (Stormwater)	50.0	gpm	LIQUID	Non-flammable
QUANTITY OF PUMPS	2	2-50% Capacity		each	MOTOR PROVIDED	Yes, with Pump
PUMPS TO OPERATE IN (PARALLEL)	Yes		SPARE PARTS	Yes, with Pump		
PUMPING PRESSURE						
SUCTION PRESSURE MAX./RATED	0.09	barg (Min)	1.3	psig (Min)	275	psig (Max)
DISCHARGE PRESSURE	3.0	barg	43.0	psig (Min)	275	psig (Max)
DIFFERENTIAL PRESSURE		bar		psi		
DIFF. HEAD		m		ft		
NPSHA		m		ft		
DENSITY: Water	1000	kg/m^3 0 ^0C	62.4	lb/ft^3 32 ^0F		
PUMPING TEMPERATURE						
NORMAL OPERATING TEMPERATURE RANGE	86	MAX (°F)	-67	MIN (°F)		
	30	MAX (°C)	-55	MIN (°C)		
ELECTRICAL						
POWER	DRIVERS*	CONTROL	Class			
VOLTAGE	TBD	120	Class 1, Div 2			
HERTZ	60	60				
PHASE	1	1				
DESIGN RATING (LBS)						
	Connection	Rating	Type	Location	MAOP	Unit
SUCTION	Screen		Open	Base	175	psi
DISCHARGE	TBD	125	FF	Top	175	psi
LOCATION						
OUTDOOR	Yes				Seismic	** See note below
UNDER ROOF	No				Wind (kph)	201
PARTIAL SIDES	No					
AT GRADE	No					Bottom of Impoundment
HEATED	No				Freeze Protection Required When Idle	Self Draining
AMBIENT TEMPERATURE RANGE	104	MAX (°F)	-67	MIN (°F)		
	40	MAX (°C)	-55	MIN (°C)		
QA INSPECTION - TESTING						
HYDROTEST	Yes		PUMP CURVE	Yes		
NONDESTRUCTIVE TEST	Vendor to Submit Procedure					

* Notes: 2. Based on extreme daily rainfall of 44.9 mm/day (1.77 inch/day) in August at Whitehorse, Yukon Weather Station. Peak hour calculated at 25% of peak day, 11.1 mm/hour (0.44 inch/hour)

3. Based on 3 acres secondary containment land area drain to impoundment

http://www.climate.weatheroffice.gc.ca/climate_normals/results_e.html?stnID=1617&lang=e&dCode=1&StationName=WHITEHORSE&SearchType=Contains&province=ALL&provBut=&month1=0&month2=12

**See: http://www.earthquakescanada.nrcan.gc.ca/hazard-alea/interpolat/index_2010-eng.php Use Site Coordinates: 60.6958 North 135.0469 West

IMPOUNDEMENT SUBMERSIBLE JOCKEY WATER PUMP

US and CANADA CUSTOMARY UNITS

FOR	Yukon Energy Corporation				SERVICE	**Impoundment Submersible Jockey Water Pump**
SITE	Whitehorse, YK				EQUIPMENT #	**P-402**
MANUFACTURER			MODEL		TYPE	Submersible, Centrifugal
Pump Size	1	Hp				
OPERATING CONDITIONS						
		Unit		Unit	SERVICE	INTERMITTENT
CAPACITY EACH PUMP[2]	2.0	m3/hour	8.8	gpm	TYPE OR NAME OF LIQUID	Stormwater
TOTAL CAPACITY REQUIRED (without spare)	2.0	m3/hour	8.8	gpm	LIQUID	Non-flammable
QUANTITY OF PUMPS	1	1-100% Capacity		each	MOTOR PROVIDED	Yes, with Pump
PUMPS TO OPERATE IN (PARALLEL)	Yes		SPARE PARTS	No		
PUMPING PRESSURE						
SUCTION PRESSURE MAX./RATED	0.09	barg (Min)	1.3	psig (Min)	175	psig (Max)
DISCHARGE PRESSURE	3	barg	44	psig (Min)	175	psig (Max)
DIFFERENTIAL PRESSURE	2.9	bar	42	psi		
DIFF. HEAD	60	m	198	ft		
NPSHA	<3	m	<10	ft		
DENSITY: Water	1000	kg/m^3 $0\ ^0C$	62.4	lb/ft^3 $32\ ^0F$		
PUMPING TEMPERATURE						
NORMAL OPERATING TEMPERATURE RANGE	104	MAX (°F)	-67	MIN (°F)		
	40	MAX (°C)	-55	MIN (°C)		
ELECTRICAL						
POWER	DRIVERS*	CONTROL	Class			
VOLTAGE	TBD	120	Class 1, Div 2			
HERTZ	60	60				
PHASE	1	1				
DESIGN RATING (LBS)						
	Connection	Rating	Type	Location	MAOP	Unit
SUCTION	Screen		Open	Base	175	psi
DISCHARGE	TBD	125	FF	Top	175	psi
LOCATION						
OUTDOOR	Yes				Seismic	** See note below
UNDER ROOF	No				Wind (kph)	201
PARTIAL SIDES	No					
AT GRADE	No					Bottom of Impoundment
HEATED	No				Freeze Protection Required When Idle	Self Draining
AMBIENT TEMPERATURE RANGE	104	MAX (°F)	-67	MIN (°F)		
	40	MAX (°C)	-55	MIN (°C)		
QA INSPECTION - TESTING						
HYDROTEST	Yes		PUMP CURVE	No		
NONDESTRUCTIVE TEST	Vendor to Submit Procedure					

* Notes: 1. Motors greater than 200 HP are 4,160 V, less than 200 Hp are 600 V

2. Based on extreme daily rainfall of 28.8 mm/day (1.113 inch/day) in August at Dawson A, Yukon Weather Station. Peak hour calculated at 50% of peak day, 14.5 mm/hour (0.56 inch/hour)

3. Based on 3 acres secondary containment land area drain to impoundment

http://www.climate.weatheroffice.gc.ca/climate_normals/results_e.html?stnID=1535&lang=e&dCode=0&province=YT&provBut=Search&month1=0&month2=1 2

**See: http://www.earthquakescanada.nrcan.gc.ca/hazard-alea/interpolat/index_2010-eng.php Use Site Coordinates: 60.6958 North 135.0469 West

FLARE PACKAGE

US and CANADA CUSTOMARY UNITS

FOR	Yukon Energy Corporation				SERVICE	**Flare Package**
SITE	Whitehorse, YK				EQUIPMENT #	**F-803**
MANUFACTURER			MODEL		TYPE	Vertical Stack Flare with Tip, Seal and Supports
TYPE OR NAME OF LIQUID	Natural Gas/LNG Vapour					
OPERATING CONDITIONS						
		Unit		Unit	SERVICE	INTERMITTENT
FLOWRATE (MIN)[1]	64.0	m^3/hour (gas)	54	SMCFD (gas)		
FLOWRATE (MAX)[2]	120	m^3/hour (gas)	760	SMCFD (gas)		
QUANTITY OF FLARE/VENT PACKAGES REQUIRED	1	1 - 100% Capacity		each	2 - Electronic Pilots	each
GAS DENSITY	TBD	kg/m^3 -160 C	TBD	lb/ft^3 -260 F		
PROCESS TEMPERATURE	104	MAX (°F)	-260	MIN (°F)		
	40	MAX (°C)	-161	MIN (°C)		
IGNITOR	Automatically Activated Electronic Ignition for Class I, Div 2. Ignition to occur after flow is sensed and after vent line has be purged of all oxygen with nitrogen bottle and solenoid valve.					
PURGE						
MECHANICAL REQUIREMENTS						
DESIGN CODE	RP-521, GPSA					
DESIGN PRESSURE	0	barg (Min)	0	psig (Min)	25	psig (Max)
MATERIAL OF CONSTRUCTION - FLARE STACK	Stainless					
INTERNAL CLADDING/COATING	No				EXTERNAL COATING	No
THERMAL INSULATION	(Bare) Not Required				Protect base from falling ice.	
HIEGHT ABOVE GRADE INCLUDING TIP3	TBD	m	TBD	ft		
GUY WIRES	Yes, if required					
CONNECTION SIZES AND DESIGN RATING (LBS)						
	Connection	Rating	Type		MAOP	Unit
FLARE/VENT STACK	TBD	ANSI 150	RF		275	psig (Max)
LOCATION						
OUTDOOR	Yes				Seismic	** See note below
UNDER ROOF	No				Wind (kph)	201
PARTIAL SIDES	No					
AT GRADE	Yes					
HEATED	No					
AMBIENT TEMPERATURE RANGE	104	MAX (°F)	-67	MIN (°F)		
	40	MAX (°C)	-55	MIN (°C)		
QA INSPECTION - TESTING						
HYDROTEST	Yes					
NONDESTRUCTIVE TEST	Vendor to Submit Procedure					

Notes:

1. For normal operations, gas flow to flare is zero. Flow of gas to flare indicates abnormal operating conditions.
2. Maximum flow rate based on 100% margin over all storage tanks venting at max boil off rate.
3. Based on maximum flow case with thermal radiation not to exceed 3,000 BTU/ft^2-hr at grade with 20 MPH wind.
4. Nitrogen sweep to activated to clear oxygen from vent pipe before flare is ignited

**See: http://www.earthquakescanada.nrcan.gc.ca/hazard-alea/interpolat/index_2010-eng.php Use Site Coordinates: 60.6958 North 135.0469 West

LNG TRUCK FUELING DISPENSER

US and CANADA CUSTOMARY UNITS

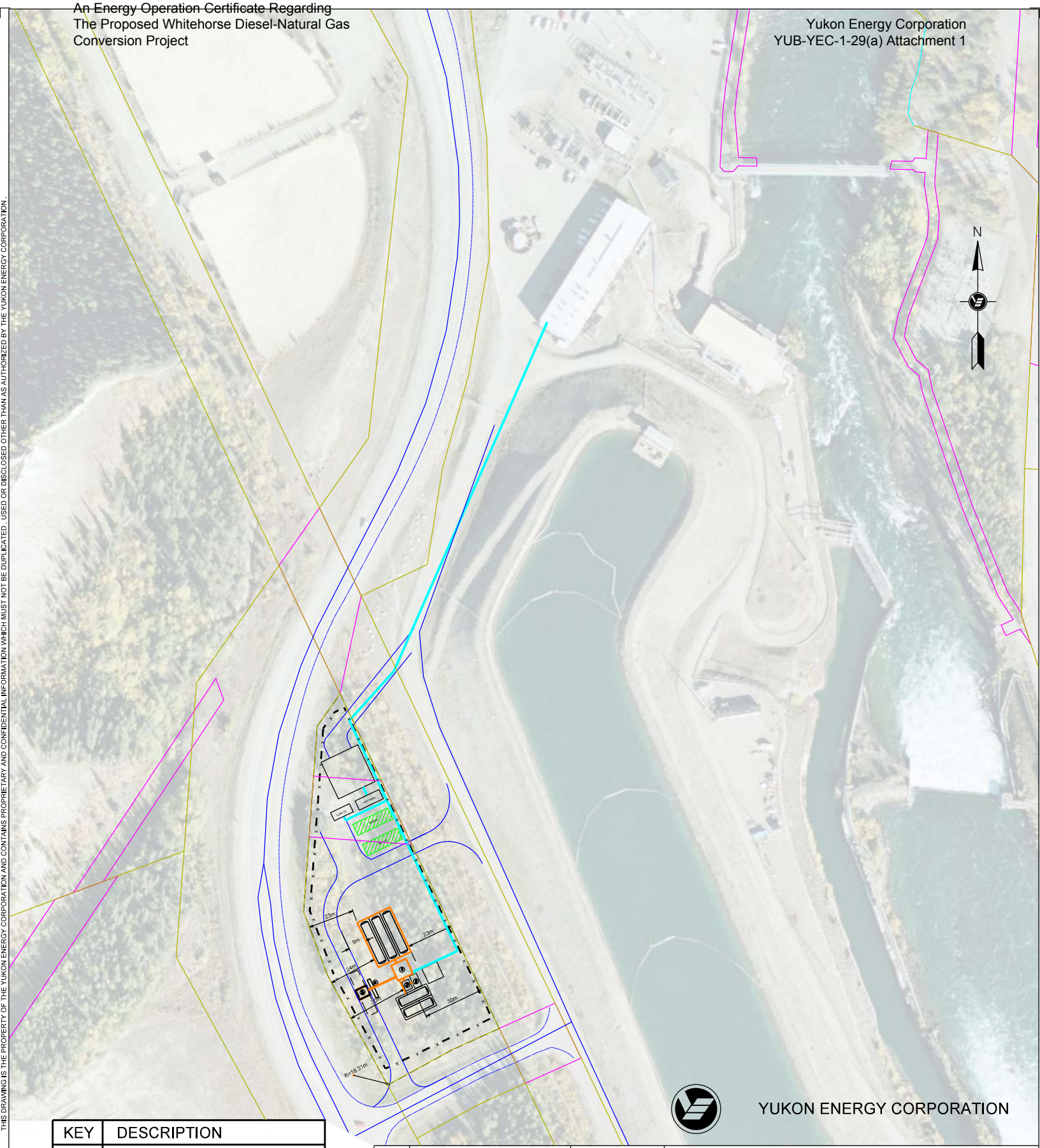
FOR	Yukon Energy Corporation				SERVICE	**LNG TRUCK FUELING DISPENSER**
SITE	Whitehorse, YK				EQUIPMENT #	**D-101**
MANUFACTURER			MODEL		TYPE	Commercial LNG Truck Fueling Dispenser
OPERATING CONDITIONS						
		Unit		Unit	SERVICE	INTERMITTENT
CAPACITY EACH DISPENSER	11.4	m3/hour (LNG)	50	gpm	TYPE OR NAME OF LIQUID	LNG
QUANTITY OF FUELING DISPENSERS	1	1-100% Capacity		each	No Pump Required	
DISPENSERS TO OPERATE IN (PARALLEL)	Provide expansion capability		SPARE PARTS	Yes, with Dispenser		
FUELING PRESSURE						
INLET PRESSURE MIN./RATED	3.4	barg (Min)	50.0	psig (Min)	Dispensing Pressure provided from P-104 A/B or P-301A/B	
INLET PRESSURE MAX./RATED	13.8	barg (Min)	200.0	psig (Min)		
MATERIAL OF CONSTRUCTION - PRESSURE COMPONENTS	304 SS				MATERIAL OF CONSTRUCTION - SUPPORTS	Carbon Steel - Skid Mounted
DENSITY (LNG)	427.56	kg/m^3 -163 ^0C	26.692	lb/ft^3 -261 ^0F		
LNG FUELING TEMPERATURE						
NORMAL OPERATING TEMPERATURE RANGE	-254	MAX (°F)	-261	MIN (°F)		
	-159	MAX (°C)	-163	MIN (°C)		
DESIGN RATING (LBS)						
	Connection	Size	Type		MAOP	Unit
LNG HOSE (LIQUID)	Quick Connect	1"	NPTF		500	psi
LOCATION						
OUTDOOR	Yes				Seismic	** See note below
UNDER ROOF	No				Wind (kph)	201
PARTIAL SIDES	No					
AT GRADE	Yes					
HEATED	No					
AMBIENT TEMPERATURE RANGE	104	MAX (°F)	-67	MIN (°F)		
	40	MAX (°C)	-55	MIN (°C)		
QA INSPECTION - TESTING						
HYDROTEST	Yes					

Note: Skid package complete with controls, meter, valves, fittings, hoses, and mechanical gauges, electronic instruments, and flow computer. No LNG Pump required.

**See: http://www.earthquakescanada.nrcan.gc.ca/hazard-alea/interpolat/index_2010-eng.php
Use Site Coordinates: 60.6958 North 135.0469 West

APPENDIX G – SITE LAYOUT

THIS DRAWING IS THE PROPERTY OF THE YUKON ENERGY CORPORATION AND CONTAINS PROPRIETARY AND CONFIDENTIAL INFORMATION WHICH MUST NOT BE DUPLICATED, USED OR DISCLOSED OTHER THAN AS AUTHORIZED BY THE YUKON ENERGY CORPORATION.



YUKON ENERGY CORPORATION

KEY	DESCRIPTION
1	IMPOUNDMENT (8.2m x 8.2m x 3m)
2	VAPORIZATION SKIDS
3	PUMP SKID
4	TANKER UNLOADING MANIFOLD
5	TRUCK CONTAINMENT (4.9m x 6.1m)

REV.	DESCRIPTION:	DATE:
1	SITE PLAN FOR PERMITTING	17-Jun-2013

SKETCH SHOWING:

LOCATION PLAN

DRAWN BY: Tara	17-Jun-2013	SCALE: 1:1250	DRWG. # FIGURE_RFP Project Site	REV. 1

APPENDIX H – SAMPLE FUEL SPECIFICATION

AGAT® Laboratories

GAS ANALYSIS

Container Identification
4002114

Operator Name	Laboratory Number
SPECTRA ENERGY	10GN395512P

Unique Well Identifier	Well Name
c-085-G/094-J-10	SPECTRA FORT NELSON GAS PLANT

Field or Area	Pool or Zone	Sampler's Company
NOT AVAILABLE	NOT APPLICABLE	AGAT/FORT ST. JOHN

Well License	Elevation	Test Type	Test No.	Name of Sampler
	KB m: GRD m:			

Test Interval or Perfs mKB	Sampling Point
	OUTLET

	Separator	Reservoir	Source	Sampled	Received
Pressure (kPa)			5000	5000	4500
Temperature			17	17	21

Date Sampled	Date Received	Date Analyzed	Date Reported	Entered By	Certified By
Mar 31, 2010	Apr 05, 2010	Apr 08, 2010	Apr 08, 2010	Mathew Bowen	Mathew Bowen

Other Information
FIELD H2S BY TUBE = 0 ppm, SAMPLE POINT - C OUTLET, SAMPLE TAKEN AT 4:00 PM

** Results relate only to the items tested*

COMP	MOLE FRACTION		PETROLEUM LIQUID
	AIR FREE AS RECEIVED	AIR FREE ACID GAS FREE	mL / m³
H2	0.0001	0.0001	
He	0.0005	0.0005	
N2	0.0115	0.0115	
CO2	TRACE	0.0000	
H2S	0.0000	0.0000	
C1	0.9748	0.9748	
C2	0.0076	0.0076	
C3	0.0028	0.0028	10.3
IC4	0.0006	0.0006	2.6
NC4	0.0008	0.0008	3.4
IC5	0.0004	0.0004	2.0
NC5	0.0003	0.0003	1.5
C6	0.0003	0.0003	1.6
C7+	0.0003	0.0003	1.9
Total	1.0000	1.0000	23.3

GROSS HEATING VALUE MJ/m³
15° C AND 101.325 kPa

Air Free As Received	Moisture & Acid Gas Free	C7+, Air Free As Received
37.99	37.99	0.06

RELATIVE DENSITY (CALCULATED) DENSITY

Moisture Free	Moisture & Acid Gas Free	C7+, Moisture Free	C7+, Portion Whole Density	C7+ Density (kg/m3)	Total Sample Density(kg/m3)
0.570	0.570	3.621	0.001	694.7	0.698

PSEUDO CRITICAL PROPERTIES (CALCULATED)

As Sampled		Acid Gas Free	
pPc (abs) kPa	pTc K	pPc (abs) kPa	pTc K
4580.6	191.8	4580.6	191.8

RELATIVE MOLECULAR MASS

Total Gas	C_7+
16.5	104.9

VAPOUR PRESSURE (Pentanes +)

78.05 kPa

H_2S g/m³

0.00

AGAT® Laboratories

GAS ANALYSIS

Container Identification
12316

Operator Name	Laboratory Number
SPECTRA ENERGY	10GN395512O

Unique Well Identifier	Well Name
c-085-G/094-J-10	SPECTRA FORT NELSON GAS PLANT

Field or Area	Pool or Zone	Sampler's Company
NOT AVAILABLE	NOT APPLICABLE	AGAT/FORT ST. JOHN

Well License	Elevation	Test Type	Test No.	Name of Sampler
	KB m: GRD m:			

Test Interval or Perfs mKB	Sampling Point
	OUTLET

	Separator	Reservoir	Source	Sampled	Received
Pressure (kPa)			5000	5000	5000
Temperature			17	17	21

Date Sampled	Date Received	Date Analyzed	Date Reported	Entered By	Certified By
Mar 31, 2010	Apr 05, 2010	Apr 08, 2010	Apr 08, 2010	Mathew Bowen	Mathew Bowen

Other Information
FIELD H2S BY TUBE = 0 ppm, SAMPLE POINT - D OUTLET, SAMPLE TAKEN AT 4:10 PM

* Results relate only to the items tested

COMP	MOLE FRACTION		PETROLEUM LIQUID
	AIR FREE AS RECEIVED	AIR FREE ACID GAS FREE	mL / m³
H2	0.0001	0.0001	
He	0.0005	0.0005	
N2	0.0114	0.0114	
CO2	TRACE	0.0000	
H2S	0.0000	0.0000	
C1	0.9758	0.9758	
C2	0.0073	0.0073	
C3	0.0025	0.0025	9.2
IC4	0.0005	0.0005	2.2
NC4	0.0008	0.0008	3.4
IC5	0.0003	0.0003	1.5
NC5	0.0002	0.0002	1.0
C6	0.0003	0.0003	1.6
C7+	0.0003	0.0003	1.9
Total	1.0000	1.0000	20.8

GROSS HEATING VALUE MJ/m³
15° C AND 101.325 kPa

Air Free As Received	Moisture & Acid Gas Free	C7+, Air Free As Received
37.94	37.94	0.06

RELATIVE DENSITY (CALCULATED) DENSITY

Moisture Free	Moisture & Acid Gas Free	C7+, Moisture Free	C7+, Portion Whole Density	C7+ Density (kg/m3)	Total Sample Density(kg/m3)
0.569	0.569	3.621	0.001	694.7	0.697

PSEUDO CRITICAL PROPERTIES (CALCULATED)

As Sampled		Acid Gas Free	
pPc (abs) kPa	pTc K	pPc (abs) kPa	pTc K
4581.1	191.6	4581.1	191.6

RELATIVE MOLECULAR MASS

Total Gas	C_7+
16.5	104.9

VAPOUR PRESSURE (Pentanes +)

69.66 kPa

H_2S g/m³

0.00

APPENDIX I – 2010 NATIONAL BUILDING CODE SEISMIC HAZARD CALCULATION

2010 National Building Code Seismic Hazard Calculation

INFORMATION: Eastern Canada English (613) 995-5548 franç ais (613) 995-0600 Facsimile (613) 992-8836
Western Canada English (250) 363-6500 Facsimile (250) 363-6565

Requested by: , June 13, 2013

Site Coordinates: 60.6958 North 135.0469 West

User File Reference: Whitehorse

National Building Code ground motions:
2% probability of exceedance in 50 years (0.000404 per annum)

Sa(0.2)	Sa(0.5)	Sa(1.0)	Sa(2.0)	PGA (g)
0.224	0.148	0.104	0.061	0.116

Notes. Spectral and peak hazard values are determined for firm ground (NBCC 2010 soil class C - average shear wave velocity 360-750 m/s). Median (50th percentile) values are given in units of g. 5% damped spectral acceleration (Sa(T), where T is the period in seconds) and peak ground acceleration (PGA) values are tabulated. Only 2 significant figures are to be used. ***These values have been interpolated from a 10 km spaced grid of points. Depending on the gradient of the nearby points, values at this location calculated directly from the hazard program may vary. More than 95 percent of interpolated values are within 2 percent of the calculated values.***

Ground motions for other probabilities:

Probability of exceedance per annum	0.010	0.0021	0.001
Probability of exceedance in 50 years	40%	10%	5%
Sa(0.2)	0.064	0.120	0.159
Sa(0.5)	0.047	0.083	0.108
Sa(1.0)	0.030	0.057	0.075
Sa(2.0)	0.018	0.034	0.045
PGA	0.036	0.065	0.085

References

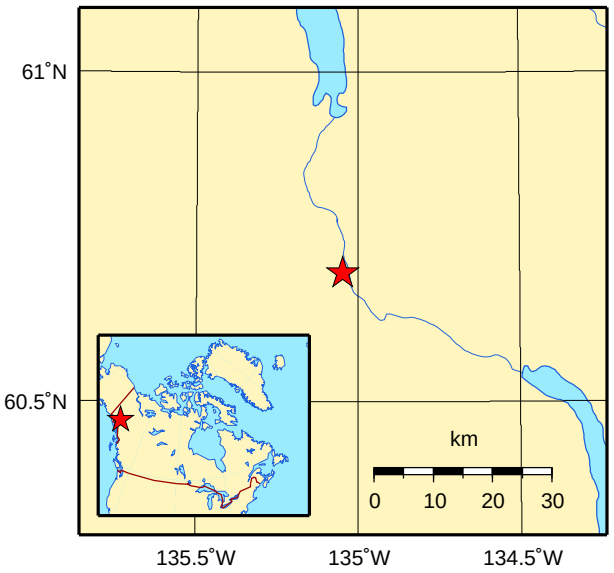
National Building Code of Canada 2010 NRCC no. 53301; sections 4.1.8, 9.20.1.2, 9.23.10.2, 9.31.6.2, and 6.2.1.3
Appendix C: Climatic Information for Building Design in Canada - table in Appendix C starting on page C-11 of Division B, volume 2

User's Guide - NBC 2010, Structural Commentaries NRCC no. 53543 (in preparation)
Commentary J: Design for Seismic Effects

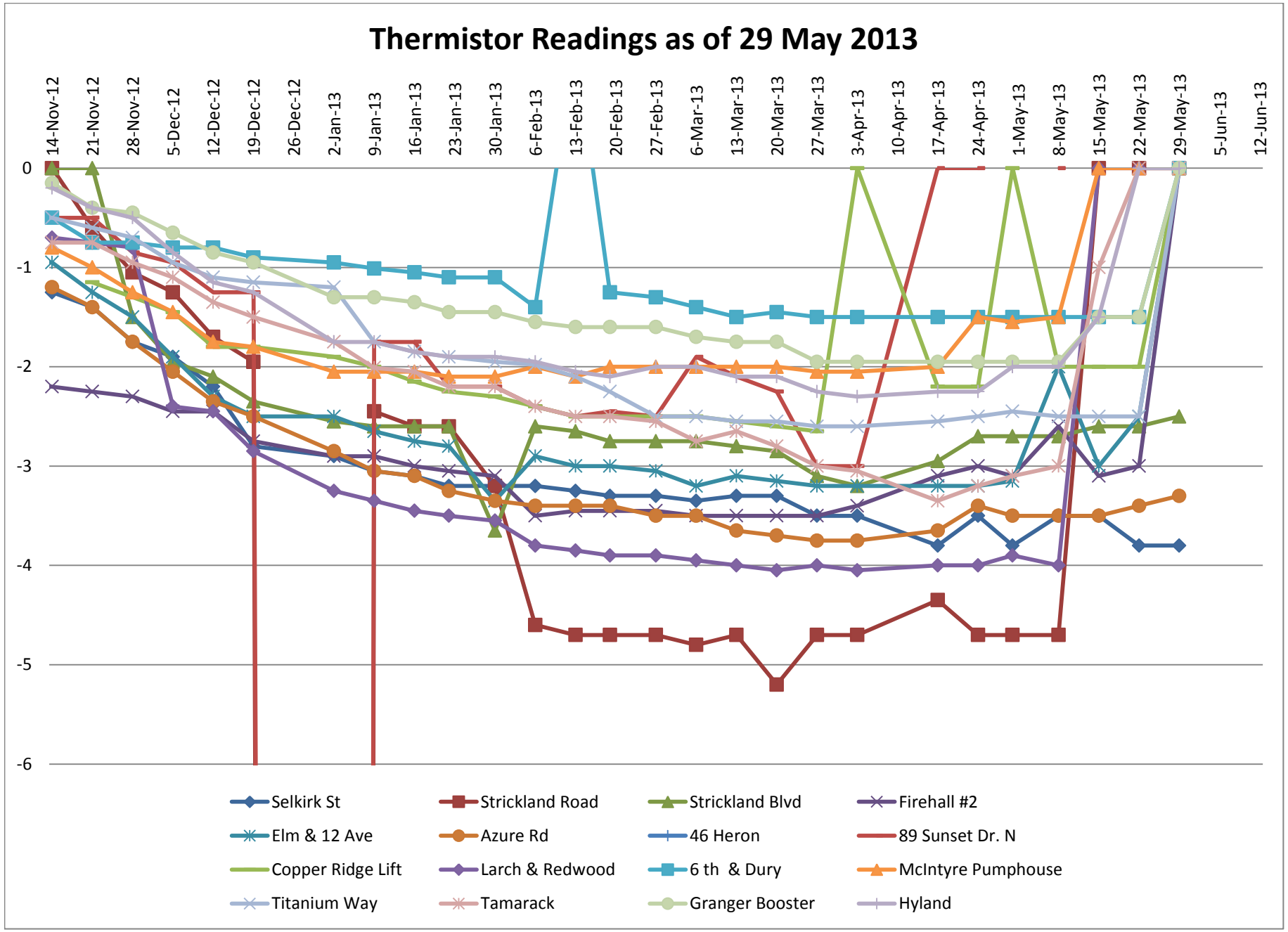
Geological Survey of Canada Open File xxxx
Fourth generation seismic hazard maps of Canada: Maps and grid values to be used with the 2010 National Building Code of Canada (in preparation)

See the websites *www.EarthquakesCanada.ca* and *www.nationalcodes.ca* for more information

Aussi disponible en français



APPENDIX J – CITY OF WHITEHORSE THERMISTOR DATA


Thermistor Readings as of 29 May 2013
14-Nov-12
21-Nov-12
28-Nov-12
5-Dec-12
12-Dec-12
19-Dec-12
26-Dec-12
2-Jan-13
9-Jan-13
16-Jan-13
23-Jan-13
30-Jan-13
6-Feb-13
13-Feb-13
20-Feb-13
27-Feb-13
6-Mar-13
13-Mar-13
20-Mar-13
27-Mar-13
3-Apr-13
10-Apr-13
17-Apr-13
24-Apr-13
1-May-13
8-May-13
15-May-13
22-May-13
29-May-13
5-Jun-13
12-Jun-13
0
-1
-2
-3
-4
-5
-6
Selkirk St
Strickland Road
Strickland Blvd
Firehall #2
Elm & 12 Ave
Azure Rd
46 Heron
89 Sunset Dr. N
Copper Ridge Lift
Larch & Redwood
6 th & Dury
McIntyre Pumphouse
Titanium Way
Tamarack
Granger Booster
Hyland

APPENDIX K – YEC HEALTH AND SAFETY POLICY AND ENVIRONMENTAL POLICY

YUKON ENERGY	HEALTH & SAFETY POLICY HS-001	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		All	Joint Health & Safety Committee	Corporate Health & Safety
		ISSUED:	REVIEW DATE:	APPROVED BY:
		January 2013	December 2013	President & CEO

1.0 Purpose

1.1 Yukon Energy takes health and safety seriously. The personal health and safety of each employee is of primary importance. The prevention of occupationally induced injuries and illnesses is of such consequence that it will be given priority over operating productivity. To the greatest degree possible, Yukon Energy's management will provide all mechanical and physical facilities required for personal safety and health, in keeping with the highest standards.

1.2 The Corporation will commit:

- to make provisions for the protection from workplace hazards;
- to the prevention of accidents and injury;
- to the promotion of workplace health and safety;
- to comply with the Yukon's *Occupational Health and Safety Act* and Regulations; and
- to investigate all incidents, accidents and near miss events occurring in the workplace.

1.3 The Corporation believes that the responsibility for health and safety is shared among the management team, the supervisors/lead hands and the employees:

- our management team is accountable for providing the overall leadership for the health and safety management system, for its effectiveness and improvement, and for providing a healthy and safe working environment;
- our supervisors and lead hands are responsible for fostering proper attitudes toward health and safety in themselves and in those they supervise, and for ensuring that all operations are performed with the utmost regard for the health and safety of all;
- our employees are responsible for wholehearted, genuine cooperation with all aspects of the Health and Safety Program, including compliance with all rules and regulations, and for continually practicing safety while performing their duties; and
- our Joint Health and Safety Committee members have a responsibility to promote health and safety at the work site. Members should be involved in developing and promoting worker safety education, health and safety programs and initiatives.

2.0 Principles

2.1 *Incidents are preventable*

- All incidents are caused and are therefore preventable.

2.2 *Health and safety system*

- Health and safety is part of the Corporation's way of doing business. Some critical elements to the health and safety system include:
  a) safe work processes and practices, with procedures that make sense;
  b) integrating safe practices into job and work planning processes;
  c) work site hazards must be identified, the risks evaluated and the appropriate controls applied;
  d) common understanding and agreement that all incidents shall be reported and investigated to determine root cause and prevention of reoccurrence;
  e) training that allows employees to learn their jobs, to reinforce existing best practices and to bring new ideas into the workplace;
  f) continuous improvements to the system: evaluate, plan, do, check, and act; and
  g) public safety education and promotion.

2.3 *Practical Loss Control*

Health and safety is part of the commitment to an overall loss prevention program. To understand the sequence of events that can lead to a loss, it is essential to understand what one is trying to prevent or control.

- **Fire Loss Control** – all Yukon Energy staff have a very important role in fire prevention and control. Work methods and workplaces will always be designed to facilitate fire loss control efforts.
- **Loss Control Procedures** – no worker shall carry out or cause to be carried out, any work process or operate or cause to be operated any tool, appliance or equipment that would create an undue hazard to the worker's health or safety or safety of any other worker.
- **Compliance** – it is the responsibility of all Yukon Energy staff to comply with all regulations and commonly recognized safe work practices and procedures in the day-to-day operations. The success of the Health and Safety Program is dependent upon the contribution toward safety awareness from every employee.

3.0 Compliance

3.1 Employees who breach this policy may be subject to disciplinary action.

YUKON ENERGY	ENVIRONMENT POLICY EN-001	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		All	Manager, Environment	Environmental Policy
		ISSUED DATE:	REVIEW DATE:	APPROVED BY:
		January 2013	January 2014	President & CEO

1.0 Policy

1.1 Yukon Energy will help sustain a healthy environment for Yukoners by maintaining a high standard of environmental responsibility and performance through the implementation of a comprehensive environmental management system. In so doing, Yukon Energy undertakes to respect and protect the environment in all its activities.

1.2 Yukon Energy recognizes its responsibility to protect the environment. This includes using resources effectively to produce electricity, minimizing impacts on the air, soil, and water, and safeguarding the health, safety and well-being of employees and the public.

1.3 Yukon Energy, through its mandate to provide safe and reliable electricity, commits to act in an environmentally responsible manner while developing and maintaining energy infrastructure and services in the Yukon.

2.0 Principles

2.1 The following guiding principles set out Yukon Energy's environmental responsibility:

We will:

- Integrate environmental considerations into decision making and planning;
- Provide employees with appropriate training to ensure their work is conducted in an environmentally responsible manner;
- Strive to achieve continuous environmental improvement through regular environmental audits of facilities and processes;
- Use energy and natural resources as efficiently as possible during the generation, transmission and distribution of electricity and the operation of our facilities and promote efficient use of electricity by our customers;
- Implement reasonable actions to prevent pollution of air, water and soil and minimize the impact of any pollution which is accidental or unavoidable;
- Meet or exceed environmental requirements defined by legislation, regulation and other commitments and agreements to which Yukon Energy subscribes;
- Be accountable to stakeholders and regulatory authorities;
- Report bi-annually to the Board of Directors on environmental performance and activities; and
- Communicate this policy to all employees and make it available to the public.

APPENDIX L – YEC JOBSITE SPILL RESPONSE PLAN

File # 2500-00-01

YUKON ENERGY **EMS-EWP-011 SPILL RESPONSE PLAN-JOBSITE**	DEPARTMENT:	INQUIRIES TO:	TOPIC:	Last Review Date
	Operations	Director, Operations	Spill Response/Hazardous Material Location Page 1 of 50	June 20, 2012
	ISSUED:	REVIEW DATE:	APPROVED BY:	Revision #
	May 2000	Annually	Director, Operations	2

JOBSITE

SPILL RESPONSE PLAN

Yukon Energy Corporation
#2 Miles Canyon Rd
Box 5920, Y1A 6S7
Whitehorse, Yukon

1.0 EMERGENCY CONTACT INFORMATION

SCC (Available 24/7)

Phone: **867-393-5324**

Cellular phone: **867-334-6910**

YEC Radio:

1. Ensure your radio is on the correct channel for your area.
2. Press and hold the "push to talk (PTT)" button (large button on left hand side of the mic)
3. While pressing the PTT button dial 1111 on the mic.
4. Voicecall your party.

If you are in the Aishihik Area, use channel 15

MOBILE RADIO OPERATOR CALL METHOD

1. Locate the your mobile channel on the Mobile Telephone Service Map according to your location
2. Change mobile channel
3. Hold radio key down to ring the operator
4. When operator answers, use you call sign to place a call to a phone number

YEC Radio Notes:

- The link can be enabled/disabled from the northern or the southern radio network.
- The link will automatically be disabled after five minutes of inactivity.
- When in the Carmacks area you will hear a beep-beep after enabling the link and a beep-beep-beep after disabling the link. Unfortunately these acknowledgment tones are not transmitted in other areas of the radio network.
- The radio link between the southern and northern networks is very long and heavy snow or ice fog between Carmacks and Stewart Crossing may render the link inoperable at times.

2.0 INITIAL ACTION/SAFE APPROACH GUIDELINES

The following are intended as Guidelines. Consider the circumstances of each event and act accordingly.

NOTIFY SSC and SUPERVISOR IF AVAILABLE **SCC Phone# 867-393-5324**

- Arrange Call-Back time, if appropriate.

ALERT OTHER EMPLOYEES/PERSONS IN AREA

- Approach spill site from up-wind or, if indoors, ensure you have a clear escape route
- Establish Perimeter Security
- Evacuate, if necessary
- Eliminate Ignition Sources
- Commence documentation

USE THE BUDDY SYSTEM

IDENTIFY MATERIAL, SPILL SOURCE, ESTIMATE QUANTITY SPILLED AND POTENTIAL FATE

- Block Potential Escape Routes, if appropriate

IF SPILL CONTINUING, CONTROL SOURCE, IF SAFE TO DO SO

- **SUBSTATION SPILLS. DO NOT ENTER UNLESS AUTHORIZED. HIGH VOLTAGE: CONTACT SCC then LEADHAND ELECTRICAL MAINTENANCE 335-2902**
- Develop Initial Incident Response Plans (Defensive, Offensive or Non-Intervention)
- Refer to product MSDS. Wear appropriate PPE.
  (See "Fast Fact Sheets" in this Plan for spills of specific products.)

SUMMON RESPONSE RESOURCES, AS APPROPRIATE

UPDATE SCC and SUPERVISOR ON PROGRESS

Note: In some instances, initial on-scene personnel will only be able to monitor and/or contain the spill with resources at hand until assistance arrives.

DO NOT PUT YOURSELF at RISK

3.0 PURPOSE AND SCOPE

At this time this Spill Response Plan covers situations related to a spill or other unintended release of a liquid, solid and/or gas that may present a threat to those in a YEC facility or to the external environs.
This spill contingency plan applies to all spills that occur at Yukon Energy's hydro and diesel facilities. The Director of Operations and Leadhands of Electrical, Mechanical and Hydro Maintenance will review the plan yearly to ensure the information is current.

Purpose

The purpose of Yukon Energy's Hazardous Materials Spill Contingency Plan is to provide a plan of action for every foreseeable spill event at all of the Yukon Energy facilities. It defines the responsibilities of key response personnel and outlines the procedures for responding to spills in a way that will minimize potential health and safety hazards, environmental damage, and clean up costs. The plan has been prepared to provide easy access to all the information needed in dealing with a spill.

It is the policy of Yukon Energy to initiate clean up activity when, in the opinion of its management, Yukon Energy is clearly associated, or likely to be associated with the spilled material. As well it is our company policy:

- To meet or surpass regulatory requirements;
- To provide protection of the environment using all of YEC's resources; when practicable
- To cooperate with other groups working on protection of the environment;
- To minimize the adverse effects of our activities on the natural and social environment;
- To keep employees, government officials and the public informed.

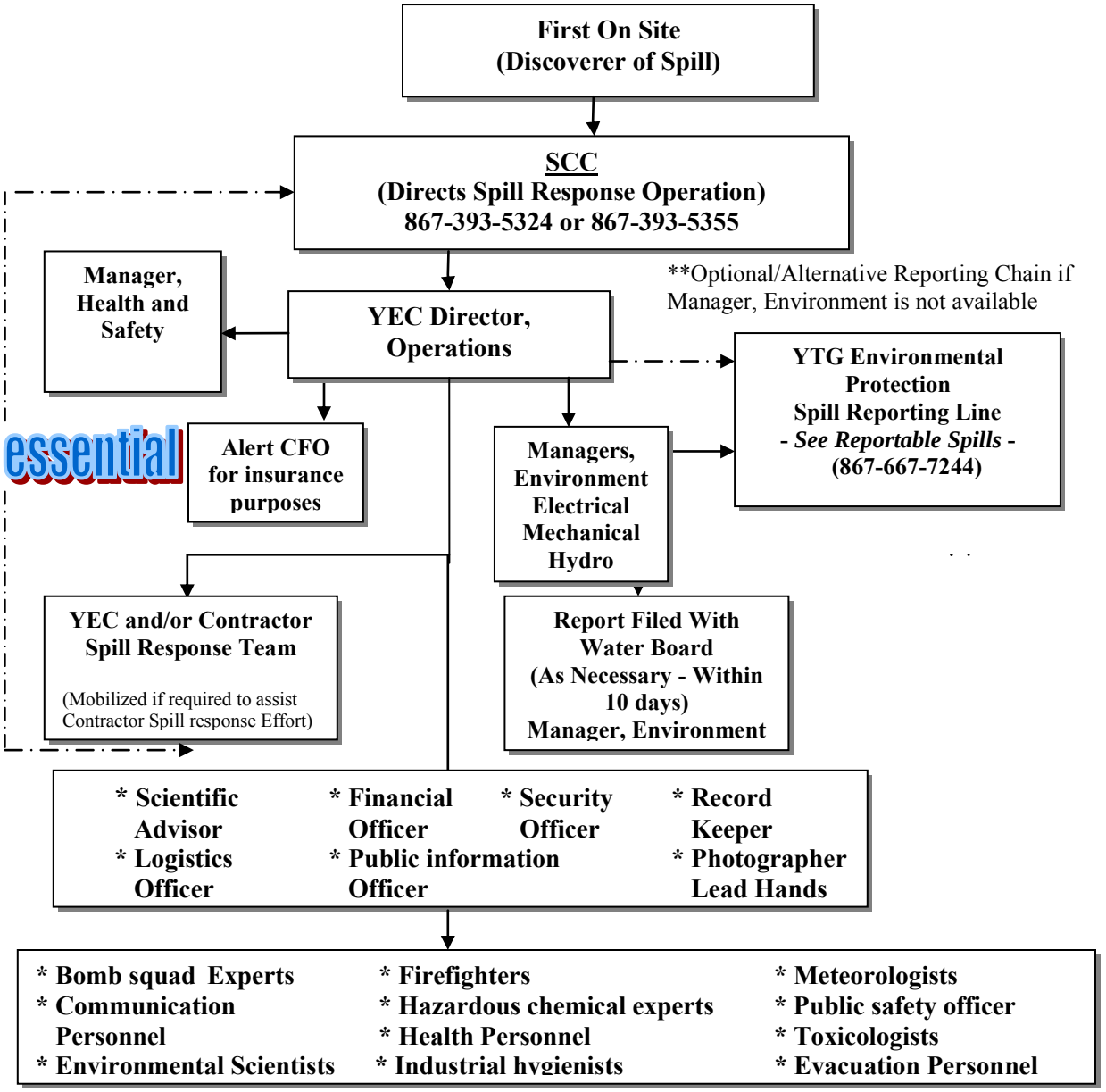
Scope

The Jobsite Spill Contingency Plan, Reporting Procedures and Hazardous Materials Locations document covers all hazardous materials stored and used at the all sites. This document covers both spills on land as well as in adjacent watercourses (e.g., the Yukon River). It is approved yearly by the Director of Operations and the Leadhands of Electrical, Mechanical and Hydro Maintenance will review the plan yearly to ensure the information is current.

4.0 NOTIFICATIONS

Figure 1. Contact/Reporting Flow Chart
Contact flow chart in the event of a fuel or oil spill. Qualified alternates will be contacted in the event someone is unavailable.

All spills of petroleum products of **5 litres** or more of fresh or unused **to permeable surface or water**, **0.5 L** of used waste oil or other hazardous materials must be reported to the 24 Hour Spill Report Line, by the Manager, Environment to insure that an investigation may be undertaken by the appropriate government authority. All amounts of all substances releases into water must be reported.



The specific information requested when a spill is reported to government is outlined in Yukon Energy's Incident Reporting & Investigation Procedures HS-000-E found here .https://sp2010.yec.yk.ca/Departments/env/Spill%20Contingency%20Plans/Forms/AllItems.a

5.0 RESPONSE ORGANIZATION

Response organization Structure (s) by Classification Level of Response

MINOR: Level 1 INCIDENT COMMANDER: **RESPONDER/SUPERVISOR**

is a spill of a minor nature that presents no significant threat to employees, property or the environment and absolutely no risk to the public. It can be cleaned up and remediated using manpower and equipment available at the facility or site.

Example: A litre of varsol was spilled on the shop floor. The spiller alerts those around him of the occurrence, that the incident has occurred and cleans the product up using a small spill kit. Waste is disposed of in an appropriate manner.

MODERATE: Level 2 INCIDENT COMMANDER: **LEAD HAND** or delegate

A medium spill event where there is potential risk to employees, property or the environment but no risk to the public. This level may require external assistance to contain, recover or remediate.

Example: A vehicle entering the Whitehorse facility has impacted and punctured several barrels of waste oil stored directly on the ground with no spill tray to catch any release.

MAJOR: Level 3 INCIDENT COMMANDER: **DIRECTOR, OPERATIONS** or delegate

A major spill event where there is a significant risk to employees, property, the environment and/or the public. Considerable internal and possibly external resources may be required to effectively respond.

Example: The 160,000L fuel tank in the yard of the Whitehorse facility has leaked and the product is escaping through a previously unidentified crack low on the secondary containment wall. The spill is spreading around the yard and entering the unpaved area adjacent to the property fence.

Responsibility to summon/manage external resources:

First Responders: SCC or personnel at the scene

Regulators: Manager, Environment or Delegate. Director of Operations

Contractors: SCC, Manager of Environment, Director of Operations, Lead hands

6.0 SPILL SITE SAFETY PLAN

Incident Name _____ ***Operational Period*** From _____ To _____

1. DESCRIBE THE INCIDENT AND SPECIFY THE SITE ENTRY OBJECTIVES

Description _____

Location _____

Incident Type

- ☐ Spill
- ☐ Gas release
- ☐ Explosion
- ☐ Fire
- ☐ Other _____
- ☐ Unknown

Site Entry Objectives under this Site Safety Plan

- ☐ Initial assessment or reconnaissance
- ☐ Account for personnel and/or rescue victims
- ☐ Source control
- ☐ Fire suppression
- ☐ Spill containment
- ☐ Spill recovery and/or cleanup

2. IDENTIFY PRODUCT HAZARDS

Consult MSDS; if no MSDS call CANUTEC at 613-996-6666 or "*666" (in Canada only)

Product Properties

Name _____
Estimated Amount _____
MSDS on Hand? _____
Gas / Liquid / Solid (circle)
Water soluble? _____
Specific gravity or vapor density _____

Product Hazards *(check all that apply)*

- ☐ Flammable (flash point _____ °C)
- ☐ Explosive (LEL range _____ to _____ %)
- ☐ Corrosive (corrodes _____)
- ☐ Reactive (reacts with _____)
- ☐ Toxic (IDLH _____; TLV _____)
- ☐ Carcinogenic

Potential Routes of Exposure to the Product *(check all that apply)*

☐ Inhalation ☐ Ingestion ☐ Eye contact ☐ Skin contact

3. IDENTIFY PHYSICAL SITE HAZARDS AND CONDITIONS

Physical Site Hazards

- ☐ Confined space
- ☐ Elevated area
- ☐ Pit or trench
- ☐ On or near water
- ☐ Unstable structure
- ☐ Electrocution
- ☐ Wildlife encounter
- ☐ Noise/vibration
- ☐ Extreme temperatures
- ☐ Low visibility
- ☐ Slip or trip hazards

Site Conditions *(as applicable)*

Air temperature _____
Wind chill temperature _____
Water temperature _____
Wind speed & direction _____
Precipitation _____
Humidity _____
Visiblity _____
Wave ht. (avg & max) _____
Speed of current _____
Direction of current _____
High/low tide times _____
High/low tide heights _____
Forecast _____
_____
_____
_____

Wind Chill Temperature Chart

Wind Speed (km/hr)

Effective temperature (°C)	0	10	15	20	25	30	35	40	45	50	55	60
10	8.6	7.9	7.4	6.9	6.6	6.3	6	5.7	5.5	5.3	5.1	
5	2.7	1.7	1.1	0.5	0.1	-0	-1	-1	-1	-2	-2	
0	-3	-4	-5	-6	-7	-7	-7	-8	-8	-9	-9	
-5	-9	-11	-12	-12	-13	-14	-14	-15	-15	-15	-16	
-10	-15	-17	-18	-19	-20	-20	-21	-21	-22	-22	-23	
-15	-21	-23	-24	-25	-26	-27	-27	-28	-29	-29	-30	
-20	-27	-29	-31	-32	-33	-33	-34	-35	-35	-36	-37	
-25	-33	-35	-37	-38	-39	-40	-41	-42	-42	-43	-43	
-30	-39	-41	-43	-45	-46	-47	-48	-48	-49	-50	-50	
-35	-45	-48	-49	-51	-52	-53	-54	-55	-56	-57	-57	
-40	-51	-54	-56	-57	-59	-60	-61	-62	-63	-63	-64	
-45	-57	-60	-62	-64	-65	-66	-68	-69	-70	-70	-71	
-50	-63	-66	-68	-70	-72	-73	-74	-75	-76	-77	-78	

This document may have been revised since it was printed. **CONTROLLED DOCUMENT –** PRINTED COPIES MAY NOT BE CURRENT. CHECK THE EMS SHAREPOINT SITE FOR MOST CURRENT VERSION

4. CHOOSE CORRECT LEVEL OF PPE (personal protective equipment)

Responders
- ☐ LEVEL A
- ☐ LEVEL B
- ☐ LEVEL C
- ☐ LEVEL D

Decon Team
- ☐ LEVEL A
- ☐ LEVEL B
- ☐ LEVEL C
- ☐ LEVEL D

A	B	C	D	*Equipment Requirement (*depends on situation)*
x	x			SCBA (self-contained breathing apparatus) or positive pressure supplied air respirator with escape SCBA
		x		Full-face or half-face respirator with appropriate cartridges
		x	x	Escape mask*
x				Encapsulating suit (chemical protective with vapor barrier)
x	x	x		Outer gloves (chemically resistant)
x	x	x		Inner gloves (chemically resistant)
x	x	x	x	Boots (chemically resistant, steel-toe and shank)
x				Disposable protective suit worn over entire ensemble
x	x	x	x	Disposable outer boot covers, chemically-resistant*
x	x	x	x	Hard hat
	x	x	x	Face shield*
		x	x	Safety glasses or chemical splash goggles
x	x	x	x	Coveralls*
x	x	x	x	Hearing protection*
x	x	x	x	Personal flotation device*
x	x	x	x	Cold weather gear*

5. SPECIFY MONITORING REQUIREMENTS

Site Safety Officer or designee is responsible for monitoring the following parameters (indicated by checked boxes) at the appropriate frequency and for immediately communicating levels requiring action to the On-Scene Commander. Action levels based on TLVs published by ACGIH.

Parameter	*Frequency*	*Action Level*	*Required Action*
☐ Oxygen		<19.5%	Wear SCBA
		>23.5%	Fire potential; stop monitoring, leave area
☐ Flammable gas		≥10% LEL	Explosion hazard; leave area
☐ Benzene		>25 ppm	Wear SCBA
		0.5 - 25 ppm	Use full-face air purifying respirator with organic vapor cartridges
☐ Carbon dioxide		>50,000 ppm	Wear SCBA
		5,000 - 50,000 ppm	Use half-face air purifying respirator with appropriate cartridge
☐ Hydrocarbons		50 to 500 ppm	Use half-face air purifying respirator with appropriate cartridge
		>500 - 2,500 ppm	Use full-face air purifying respirator with appropriate cartridge

6. BRIEF ALL PERSONNEL

Site Diagram attached? ☐ Yes ☐ No

Reviewed with all team members (check all applicable items)

- ☐ Buddy system
- ☐ Hazards / conditions on site
- ☐ Emergency hand signals
- ☐ Evacuation alarm
- ☐ Evacuation / escape route
- ☐ Criteria for immediate evacuation
- ☐ Radio communications
- ☐ Location of first aid/rescue gear
- ☐ Required PPE
- ☐ Safe access route to site

Prepared by Site Safety Officer — *Approved by* On-Scene Commander

Signature — Date/Time — Signature — Date/Time

Monitoring equipment will be provided by the qualified contractor. No monitoring equipment is kept on YEC premises.

7.0 MATERIAL PROPERTIES

MSDS

Refer to the MSDS binder is available at all control rooms at each plant location and is updated every 3 years by Health and Safety. In the diesel plant for Aishihik, Whitehorse and Dawson, the MSDS binder is located in the Operators office.

PPE

Use/wear the appropriate PPE as recommended by the MSDS sheet. The appropriate PPE is mandatory.

8.0 EQUIPMENT/SERVICES

Table 1. YUKON ENERGY OPERATIONAL LOCATIONS AND AVAILABLE EQUIPMENT

ITEM	Whitehorse, Outside main fuel tank	Whitehorse Spill Trailer	Aishihik	Faro	Faro	Dawson fuel shack	Dawson City inside Diesel Plant	Callison	Callison Garage	Mayo Hydro Plant	Mayo Diesel Plant	Mayo Substation	Fuel Oil Facility	Faro Drury Creek
Response Material Description	Spill Kit (Rocky Mountain)	Trailer	Large Spill Kit	Spill Response Kit (Rocky Mountain)		Spill response kit wheeled	Large yellow box (seewolf)	OSK overpack spill kit		Spill response kit	Spill response kit	Spill Response Kit		
Overpacks		3												
15" x 18" Sheets	100			100		100				Sorbent cloth for soaking up fuel and oil	Camera			
Small pillows 8" x 18"	6			6		5	1	6						
Large pillows 18" x 18"	2			2	Some	1	1	2						
Socks 3" x 8'	5			5		5		6						
Socks 3" x 4'	2			2		2		2						
Socks 3" x 3"	1													
Socks 3" x 10Ft (oil only)							4							
5" x 10' Oil Boom				2										
10' x 4" Boom		1+2 bags									1			
10' x 8" boom		2												
Plug Pattie instant leak stop				1		1	1	1						
OS410 Oilwik Booms			8											
OS810 Oilwik Booms			4											
OS100 Oilwik pads			150											
OS1800 Oilwik sweep			1											
OP16 Oil only pillows			16											
P60 Spill Box														
Rags		50												

ITEM	Whitehorse, Outside main fuel tank	Whitehorse Spill Trailer	Aishihik	Faro	Faro	Dawson fuel shack	Dawson City inside Diesel Plant	Callison	Callison Garage	Mayo Hydro Plant	Mayo Diesel Plant	Mayo Substation	Fuel Oil Facility	Faro Drury Creek
Response Material Description	Spill Kit (Rocky Mountain)	Trailer	Large Spill Kit	Spill Response Kit (Rocky Mountain)		Spill response kit wheeled	Large yellow box (seewolf)	OSK overpack spill kit		Spill response kit	Spill response kit	Spill Response Kit		
Bales (100) Absorbant pads (for coolant, picks up water)							1							
Bales (100) Absorbant pads (does not pick up water)							1	1	1					
Absorbant rolls 150ft x30"(new)		1					1							
Absorbant rolls (open)		1												
150 Gallon pop up pool		1												
20 gallon pop up pool		1												
Granular sorbent (multi-zorb)	1 bag			1		1		1						
Granular "floor dry"		1, 33lb bag												
Granular oil absorbant		2, 25 lbs bag					2, 30lb bags							
Liquid waste barrells		2							1					
solid waste barrells		3												
Solvent		4L												
Drain covers	3			1			4	1						
Disposal bags				2	some	2								
Gloves: Nitrite	2			2	some	2	2	2						
Chemical splash goggles	2	1		2		2	2	2						
Disposal Poly coated overalls	2	12	5	2		2	2	2						
Rain Suit		1								2				
Organics respirator		1				1	2	2						
Pairs rubber gloves		4								2				
High visibility safety vests		4												
Pairs Rubber Boots		6					2							
Camera (disposable)		1								1	1			
Road hazard triangles		3												
Pick axe		1												
Rake		1												
Shovel		1		1			2							

ITEM	Whitehorse, Outside main fuel tank	Whitehorse Spill Trailer	Aishihik	Faro	Faro	Dawson fuel shack	Dawson City inside Diesel Plant	Callison	Callison Garage	Mayo Hydro Plant	Mayo Diesel Plant	Mayo Substation	Fuel Oil Facility	Faro Drury Creek
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Push Broom		1												
Nylon hand broom		1												
Plastic Dust pan		1												
Spades		2												
Rolls of polyethelene 6mi, 102" x 100ft							2							
100' bags of poly rope		2												
Roll caution tape (1000ft)							1							
Flashlights		3												
Pylons		4												
All purpose tarp 24ftx 40ft							2							

***Edits of this inventory will be catalogued and sent to the Environmental coordinator to update the master list**

Table 2. Inventories/services supplied by contractor/consultant in the Whitehorse area

Joint Use Spill Response Trailer used by the Petroleum Companies in Whitehorse located at the Whitehorse Fire Department

NAME	PHONE/ADDRESS	EQUIPMENT/SERVICES AVAILABLE	SERVICE AREA
Arctic Backhoe	334-1911	If spill containment needs external resources (Pumping out an existing, leaking tank) 1 large tank truck 2000 Gallon 1Small tank truck 300 Gallon Excavators Contaminated material treatment facility	Whitehorse/Southern lakes
Ajax	667-4800	Spill kits, sorbents, containment berms etc..	
Acklands Grainger	667-6660	Spill kits, sorbents, overpacks, spill trays	
Capital Towing	667-2403	Tow trucks	Whitehorse and Area
Groundtrax Environmental	667-2515	Provides contaminated site assessment, and corrective action plan preparation services.	Whitehorse/Southern lakes
General Waste Management	668-4004	If spill containment needs external resources Carries inventory of Sorbents Crew available to clean up and mop up Capacity to dispose of contaminant Bobcats, tractors and trailers Vacuum service for hydro carbons	Whitehorse/Southern lakes
Laberge Environmental Services	1-405 Ogilvie St Whitehorse Y.T. Phone: (867) 668-6838 668-6838	Provides incident command, spill response, contaminated site assessment, and corrective action plan preparation services.	Yukon-wide
MacPherson Rentals	633-4426	Heavy equipment	
Petro Canada	110 Galena Rd Whitehorse Y.T. Phone: (867) 667-2468	Vacuum trucks	
Northwest Vacuum	667-7854	Vacuum trucks	
Sunset Septic	633-2907	Vacuum Trucks for fuel transfer	
Skookum Contracting	668-6326	Heavy equipment	
Yukon Explosives	667-6241	Spill response kits, sorbents, other response inventory	

Table 3. Inventories/services supplied by contractor/consultant in the Aishihik area

Contractor name	Phone	Available resources	Region
Arctic Backhoe	(867) 633 5951 (867) 334-1911	If spill containment needs external resources (Pumping out an existing, leaking tank) 1 large tank truck 2000 Gallon 1Small tank truck 300 Gallon Excavators Contaminated material treatment facility	Whitehorse/Southern lakes
Champagne/Aishihik First Nations	Phone: 1-(867)-634-2288 or 2963		PO Box 5309 Haines Junction, Y.T.
Ralph Hotte Contracting:	Phone: 1-(867)-634-2104 or 2958	Excavators	PO Box 5307 Haines Junction, Y.T.

Table 4. Inventories/services supplied by contractor/consultant in the Dawson area

NAME	PHONE/ADDRESS	EQUIPMENT/SERVICES AVAILABLE	SERVICE AREA
Seewolf Enterprises	867-993-6644	Spill response products. Oil / Water separator. Barrel vacuum pump.	Box 1576 Dawson City, home base with warehousing in Whitehorse.
Grenon Enterprises	867-993-5761	Excavator, Dump trucks, Loaders	Box 421 Dawson City Y.T.
Gammie Trucking	867-993-5392	Backhoe, Loader, Bobcat	Box 138 Dawson City, Y.T
Gillespie Equipment	867-993-6025	Vacuum Truck, Small backhoe,	Box 100 Dawson City

Table 5. Inventories/services supplied by contractor/consultant in the Faro area

NAME	PHONE/ADDRESS	EQUIPMENT/SERVICES AVAILABLE	SERVICE AREA
Pat McCracken Town Foreman	(867)-994-2758 – shop (867) 994-2728 – work	Store of large absorbants, mattings *No pumper trucks in the area	Faro, Yukon
Mark Vanio **Vanio Construction**	(867) 994-3460 Mobile 2M-844	Excavators *No pumper trucks in the area	Faro, Yukon

Table 6. Inventories/services supplied by contractor/consultant in the Mayo /Stewart areas

NAME	PHONE/ADDRESS	EQUIPMENT/SERVICES AVAILABLE	SERVICE AREA
Ewing Transport	(867)-996-2237	Tracker and tanker ETV with attendant Water tank Generator Trash pumps Excavator, backhoe Loader	Mayo, Yukon
Wilf's Contracting	(867) 996-2531	Crawler, skidder, grader Excavator, water truck with pump	Mayo, Yukon
Jack Smith	867-996-2273	D7 Cats and a small loader	Mayo, Yukon
Paul Martin	867-996-2046	Bobcat, Small excavator and dump truck	Mayo, Yukon

9.0 CONTACT DIRECTORY

Yukon Energy SCC **867-393-5324**
867-393-5355
800-676-2843

Emergency Services	Fire	Ambulance	Police
Dawson City	993-2222	993-4444	993-5555
Faro	994-2222	994-4444	994-5555
Mayo	996-2222	996-4444	996-5555
Whitehorse	911	911	911
Aishihik (Haines Junction)	634-2222	634-4444	634-5555

Yukon Energy Contacts

Yukon Energy Director of Operations	867-393-5317 (w) 867-334-8139 (cell)
Yukon Energy Manager, SCC, Mechanical Operations	867-393-5366 (w) 867-334-6904 (cell) 867-668-4479 (h)
Yukon Energy Manager, Electrical, Maintenance and T&D	867-393-5383(w) 867-334-6586 (cell) 867-668-6190 (h)
Yukon Energy Lead Hand, Transmission & Distribution	867-667-3607 (w) 867-334-1540 (cell)
Yukon Energy Lead Hand, Mechanical Maintenance	867-393-5384 (w) 867-335-2863(cell) 867-667-6398 (h)
Yukon Energy Lead Hand, Electrical Maintenance	867-393-5370 (w) 867-335-2902 (cell) 867-633-5090 (h)
Yukon Energy Manager, Environment	867-393-5350 (w) 867-333-0300 (cell) 867-393-4866 (h)
Yukon Energy Lead Hand, Hydro Maintenance	867-393-5382 (w) 867-334-7940 (cell)
Yukon Energy Manager, Health and Safety	867-393-5353 (w) 867-334-2073 (h)

External Agency Contacts

CANUTEC National Advisory Centre offering advice On dangerous goods emergencies	Phone (613) 996-6666
Fire Marshall National Fire Code (fuel storage) (work)	Phone: (867) 667-5417
City of Whitehorse Fire Chief	Phone: 668-8383
Department of Environment, YTG, Whitehorse. Yukon	Phone: (867) 667-7244 (24 Hours) Fax: (867) 667-7962
Environmental Protection Act (work) Spill Regulations	Phone: (867) 667-3436
Water Inspections Section (work) Yukon Government Yukon Waters Act	Phone (867) 667-3227
Canadian Environmental Protection Agency (work) Fisheries Act PCB Regulations	Phone (867) 667-3470
Department of Fisheries and Oceans Contact if spill or release into water	Phone (867)-393-6722
City of Whitehorse, Public Works, Manager Contact if spill or release in water or soil On City lands	Phone (867)-668-8351

10.0 SITE SPECIFIC INFORMATION: ALL SITES

According to YEC's Water Use Licence for the Whitehorse Rapids Facility HY99-010;

- A detailed written report on any such spill event including, but not limited to, dates, quantities, parameters, causes and other relevant details and explanations, shall be submitted to the Yukon Water Board not later than 10 days after the occurrence, as well as included in the annual report.

- YEC and its contractors shall maintain a log book of all spill or unauthorized discharge occurrences, including spills that are less than the reportable quantities under the Yukon *Spills Regulations.* The log book shall be made available at the request of the inspector. The log book shall include, but not necessarily be limited to:

    - Date and time of the spill;
    - Substance spilt or discharged;
    - Approximate amount spilled or discharged;
    - Distance between the spill or discharge and the nearest watercourse; and
    - Remedial measures taken to contain and clean-up the spill area or to cease the discharge

These are written in the log book by the first responder, Lead Hand or Director of Operations depending on the severity of the spill. See page 6 for response organization structure.

11.0 SITE SPECIFIC SCENARIOS

SCENARIO 1

During a short break in the training several of the students were chatting in the parking lot north west of the S150 substation and west of the main office building.
They observed a tank truck enter the main gate, hit what they took to be a patch of ice, ram through the protective tank safety berm before impacting the tank. The result was an approximately 30cm long crack in the tank 1 metre above the ground. At its widest, in its centre, the fissure was 3cm wide tapering away at both sides.
The students saw the driver stumble from the tank truck cab and collapse against the perimeter fence adjacent to the tank.
The YEC President was leaving his car in the parking lot. Prior to entering the building and knowing the reason for the class, instructed the attendees to assume command of the incident.

1. **NOTIFY SUPERVISOR OR SSC**

- Call SCC and Director of Operations
- Arrange Call-Back time, if appropriate.
- Incident commander will call all emergency response teams

2. **ALERT OTHER EMPLOYEES/PERSONS IN AREA**

- Approach spill site from up-wind or, if indoors, ensure you have a clear escape route
  - Check to see if tanker truck is intact and not spilling onto ground
  - Check on the person that stumbled from the truck and remove him from the scene
  - Check cab of truck for any other passengers
  - Call YEC advanced first aiders to tend to the driver
  - Check inside berm for any YEC employees

- Establish Perimeter Security. Stop people from going in and out of the YEC gate. Call police to do this or other YEC group. Use danger tape around the area, restricting access. Keep everyone inside buildings until clean up is complete

- Evacuate main corporate building and diesel plants, if necessary

- Eliminate Ignition Sources. Shut off power going to tank fed from inside P126. SCC will call contractor with a vacuum truck to pump the diesel out of the tanker truck. Pads and absorbents are thrown down where liquid has spilled.

- Commence documentation

USE BUDDY SYSTEM

3. **IDENTIFY MATERIAL, SPILL SOURCE, ESTIMATE QUANTITY SPILLED AND POTENTIAL FATE**

- Block Potential Escape Routes, if appropriate

4. **IF SPILL CONTINUING, CONTROL SOURCE, IF SAFE TO DO SO**

   - Develop Initial Incident Response Plans (Defensive, Offensive or Non-Intervention)
   - Refer to product MSDS. Wear appropriate PPE.
     (See "Fast Fact Sheets" in this Plan for spills of specific products.)

5. **SUMMON RESPONSE RESOURCES, AS APPROPRIATE**

6. **UPDATE SUPERVISOR AND/OR SCC ON PROGRESS**

7. **COMPLETE DETAILED INCIDENT REPORT**

Table 7. Other Possible Scenarios

Hazardous Materials and Location	Spill Response Task			
	Assess the Spill	**Secure the Area**	**Contain and Eliminate the Spill Source**	**Clean Up Spilled Material Decontaminate Equipment Dispose of Spilled & Contaminated Material[1]**
Diesel Plant Storage – Gardinia 30W, Caprinius HPE 40W, Diesel, Varasol, Anti-Freeze	• Any considerable losses in the dip readings from one check to the next • Any fuel/lubricants smells or any pools on the floor	Inside the diesel plant	• Cover drains with the drain covers from the spill kit. • Use leak filler if leak is accessible and if it is safe to do so	• Use granular sorbents and sorbent sheets to mop up the spill • Hydrocarbon soiled materials will be disposed of in barrels and sealed. Barrels are located in the spill trailer. • Special waste is picked up is once a year by Environment Yukon
Waste oil	• Oil smells or any pools outside the waste oil containment	Outside the diesel plant in waste oil containment	• Use the spill kit located next to WD3 • Use oilwik boom around the spill site	• Use granular sorbents and sorbent sheets • Dig up the area to assess the extent of the spill • Place the contaminated soil in a poly lined temporary containment or a metal bin. • Attain a contaminated soil removal permit and transport to a land treatment facility
Any hazardous material	• See material flowing in the Whitehorse YEC yard	Cover the man holes immediately and contain the spill	• Use the Spill response trailer. Use man hole covers and a sorbent boom	• Clean up material with sorbents and discard appropriately

12.0 APPENDIX A: FORMS

ICS 201 –BREIFING DOCUMENT
ICS 214A – INDIVIDUAL LOG
Safe action/Initial Action Checklists by Substance

- **Diesel Fuel**
- **Caprinus HPE 40**
- **Coolant**
- **Gadinia AL 30**
- **Teresso 46**
- **Varsol**
- **Waste Oil**
- **Voltesso 35**
- **SF6**

Appendix A1: **ICS 201-BRIEFING DOCUMENT**

Purpose. The Incident Briefing form provides the Incident Commander (YEC Site Supervisor) with basic information regarding the incident situation and the resources allocated to the incident. It also serves as a permanent record of the initial response to the incident.

Preparation. The briefing form is prepared by the Incident Commander (YEC Site Supervisor) for presentation to the incoming Incident Commander along with a more detailed oral briefing. Proper symbology should be used when preparing a map of the incident.

Distribution. After the initial briefing of the Incident Commander (YEC Site Supervisor) and General Staff members, the Incident Briefing is duplicated and distributed to the Command Staff, Section Chiefs, Branch Directors, Division/Group Supervisors, and appropriate Planning and Logistics Section Unit Leaders. The sketch map and summary of current action portions of the briefing form are given to the Situation Unit while the Current Organization and Resources Summary portion are given to the Resources Unit.

1. Incident Name:	2. Prepared by: Date: Time:	INCIDENT BRIEFING ICS 201-OS (pg 1 of 4)

3. Map/Sketch (include maps drawn here or attached, showing the total area of operations, the incident site/area, overflight results, trajectories, impacted shorelines, or other graphics depicting situational and response status)

INCIDENT BRIEFING	June 2000	ICS 201-OS (pg 1 of 4)

1. Incident Name:	2. Prepared by: Date: Time:	INCIDENT BRIEFING ICS 201-OS (pg 2 of 4)

4. Initial Incident Objectives

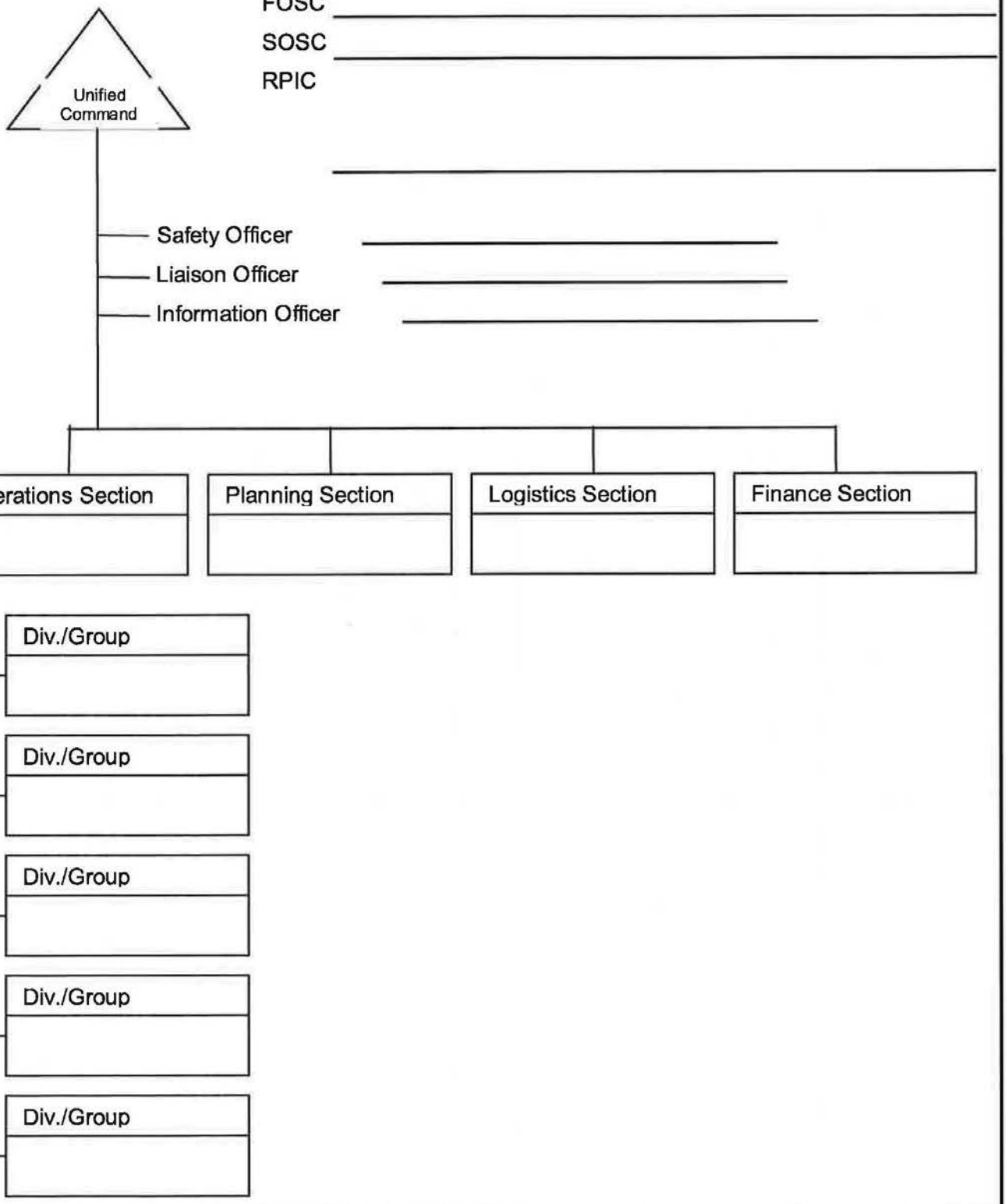
5. Summary of Current Actions

Time	Action/Note

INCIDENT BRIEFING June 2000 ICS 201-OS (pg 2 of 4)

1. Incident Name:	2. Prepared by: Date: Time:	INCIDENT BRIEFING ICS 201-OS (pg 3 of 4)

3. Current Organization



INCIDENT BRIEFING	June 2000	ICS 201-OS (pg 3 of 4)

1. Incident Name:	2. Prepared by: Date: Time:	INCIDENT BRIEFING ICS 201-OS (pg 4 of 4)

7. Resources Summary

Resources Needed	Time Ordered	Resources Identifier	ETA	On-Scene?	NOTES: (Location/Assignment/Status)

Appendix A2-: **ICS 214A – INDIVIDUAL LOG**

Purpose. The Unit Log is used to record details of unit activity including strike team activity. The file of these logs provides a basic reference from which to extract information for inclusion in any after-action report.

Initiation of Log. A Unit Log is initiated and maintained by head of the spill response effort.

1. Incident Name	2. Operational Period (Date / Time) From: To:	INDIVIDUAL LOG ICS 214a-OS
3. Individual Name	4. ICS Section	5. Assignment / Location

6. Activity Log	Page of

Time	Major Events

7. Prepared by:	Date / Time

INDIVIDUAL LOG June 2000 ICS 214a-OS

Record all personal activity --> Supervisor at end of shift --> Documentation Unit

Appendix A3-9: **SAFE ACTION/INITIAL ACTION CHECKLISTS BY SUBSTANCE**

Purpose. The purpose of the Safe Action/Initial Action Checklists by substance are to provide safety measures, PPE to be worn, first aid, emergency response, physical and chemical properties of a particular substance.

Use: These checklists are to be used as initial first action by the first responder.

Appendix A3: **DIESEL FUEL -SAFETY MEASURES**

- May cause eye, respiratory and skin irritation, headache, nausea, mental confusion, unconsciousness and death
    - Wear appropriate PPE
- Combustible liquid, may form explosive vapours
    - Eliminate ignition sources and monitor for combustible gases
- May accumulate static electricity
    - Ground and bond during transfers
- Vapours heavier than air
    - Stay out of low areas and confined spaces

Personal Protection

- 02 - <20% SCBA MUST BE WORN
- 02 = 20% Consider respirator with Organic Vapour cartridges
- Wear other required PPE, as appropriate

First Aid

- **Eyes**
    - Flush eyes immediately with fresh warm water (40C-45C) for at least 15 minutes holding lids open. DO NOT USE excessively hot or cold water
    - Get medical attention
- **Skin**
    - Remove contaminated clothing
    - Wash contaminated skin thoroughly with soap and warm water
    - Obtain medical attention if irritation or redness develops
- **Inhalation**
    - Move person to fresh air
    - Administer oxygen therapy, as necessary
    - WHEN OXYGEN IS IN USE, ENSURE NO SMOKING
- **Ingestion**
    - If swallowed, DO NOT INDUCE VOMITING and obtain immediate medical attention
    - Small amounts of materials that enter the mouth should be rinsed out until taste of substance is eliminated. Remove dentures and rinse well, if applicable

For Further Information Consult Product MSDS

Appendix A3: **DIESEL FUEL –EMERGENCY RESPONSE**

Spill

- Isolate area, restrict access and evacuate if necessary
- Eliminate ignition sources
- Advise SCC and/or Supervisor (867) 393 5324/ 393 5355
- Request assistance
- Attempt to limit escape routes and shut off source – IF SAFE TO DO SO
- Contain and recover using sorbent materials and/or vacuum truck

Fire

- Isolate area, restrict access and evacuate if necessary
- Summon qualified assistance
- Shut off fuel to fire, IF SAFE TO DO SO
- If qualified, extinguish with dry chemical extinguisher, CO2, foam and/or H20 fog. DO NOT use a direct stream of water as it may spread the fire

Physical & Chemical Properties

Appearance:	Clear white to pale/bright yellow liquid
Odour:	Petroleum
Flashpoint:	Approximately > + 37.8C
Solubility in water:	Insoluble
Specific Gravity:	0.78 – 0.85
Vapour Density:	> than 1 (Air = 1)

For Further Information Consult Product MSDS

Appendix A4: **Caprinus HPE 40- SAFETY MEASURES**

- Product is not expected to be irritating and has a low level of toxicity under normal use
  - Wear appropriate PPE
- Material will not burn unless preheated. Avoid excessive heat as it may cause formation of vapours or mists in which case SCBA must be worn
  - Eliminate ignition sources
- Spilled material may create a slipping hazard

Personal Protection

- 02 - <20% SCBA MUST BE WORN
- 02 = 20% Consider respirator with NIOSH approved Organic Vapour cartridges
- Wear other required PPE, as appropriate

First Aid

- **Eyes**
  - Flush eyes immediately with fresh warm water (40C-45C) for 15 minutes holding lids open
  - Get medical attention if irritation occurs and persists
- **Skin**
  - Wash contaminated skin with mild soap and warm water. Remove contaminated clothing
  - Get medical attention if irritation occurs and persists
- **Inhalation**
  - Move exposed person to fresh air
  - Administer oxygen therapy, if necessary and only if trained
  - WHEN OXYGEN IS IN USE, ENSURE NO SMOKING
- **Ingestion**
  - Not normally a factor.
  - If swallowed, DO NOT INDUCE VOMITING and get immediate medical attention
  - If vomiting occurs, keep the head low to prevent product entering the lungs

For Further Information Consult Product MSDS

Appendix A4: **Caprinus HPE 40- EMERGENCY RESPONSE**

Spill

- Isolate area, restrict access and evacuate if necessary
- Eliminate ignition sources
- Spill may create slipping hazard
- Advise Supervisor and/or SCC # (867) 393 5324/ 393 5355Request assistance
- Attempt to limit product escape routes and shut off source – IF SAFE TO DO SO
- Contain and recover using sorbent materials and/or vacuum truck

Fire

- Isolate area, restrict access and evacuate if necessary
- Summon qualified assistance
- Shut off fuel to fire, IF SAFE TO DO SO
- If qualified, extinguish with dry chemical extinguisher, CO_2, foam and/or H_20 fog. DO NOT use direct stream of water as it may spread fire

Physical & Chemical Properties

Appearance:	Liquid. Clear, bright
Odour:	Hydrocarbon odour
Flashpoint:	+ 264 C
Solubility in water:	Insoluble
Specific Gravity:	< 1 (Water = 1)
Vapour Density:	Not available

For Further Information Consult Product MSDS

Appendix A5: **COOLANT - SAFETY MEASURES**

- DO NOT taste or swallow antifreeze. DO NOT breathe vapours or fumes
  - Wear appropriate PPE
- Material is unlikely to burn unless preheated
  - Use SCBA if entering a confined space where this substance is burning
- It may possibly accumulate static electricity
  - Ground and bond containers during transfer

Personal Protection

- 02 - <20% SCBA MUST BE WORN
- 02 = 20% Consider respirator with Organic Vapour cartridges
- Wear other required PPE, as appropriate

First Aid

- **Eyes**
  - Flush eyes immediately with fresh warm water (40C-45C) for 15 minutes holding lids open
  - Obtain medical attention if irritation persists
- **Skin**
  - Wash contaminated area with plenty of mild soap and water. Remove contaminated clothing
  - If irritation occurs and persists, obtain medical attention
- **Inhalation**
  - Move exposed person to fresh air
  - Administer oxygen therapy, as necessary and only if trained
  - WHEN OXYGEN IS IN USE, ENSURE NO SMOKING
  - If symptoms occur, obtain medical attention
- **Ingestion**
  - Remove dentures, if any, and rinse. Rinse out mouth until taste of product dissipates
  - If swallowed, DO NOT INDUCE VOMITING. Get immediate medical attention
  - If vomiting occurs, keep the head low to prevent product entering the lungs.

For Further Information Consult Product MSDS

Appendix A5: **COOLANT - EMERGENCY RESPONSE**

Spill

- Isolate area, restrict access and evacuate if necessary
- Eliminate ignition sources though substance unlikely to ignite
- Advise Supervisor and/or SCC # (867) 393 5324/SCC Cell. (867) 393 5355
- Request assistance
- Attempt to limit product escape routes and shut off source – IF SAFE TO DO SO
- Contain and recover using appropriate sorbent materials and/or vacuum truck

Fire

- Isolate area, restrict access and evacuate if necessary
- Use SCBA if entering a confined space where this substance is burning
- Summon qualified assistance
- Shut off fuel to fire, IF SAFE TO DO SO
- If qualified, extinguish with dry chemical extinguisher, CO_2, foam and/or H_20 fog
  DO NOT use a direct stream of water as it may spread fire

Physical & Chemical Properties

Appearance:	Liquid. Yellow Colour
Odour:	Faint or mild
Flashpoint:	+ 127 C
Solubility in water:	Soluble
Lower/Upper Explosive Limits:	Lower 3.2% Upper: Not stated
Vapour Density:	2.1 (Air = 1)

For Further Information Consult Product MSDS

Appendix A6: **GADINIA AL 30 – SAFETY MEASURES**

- Exposure most likely to occur through skin contact or from inhalation of mechanically or thermally generated oil mists. Normally, product has a low level of toxicity
    - Wear appropriate PPE
- Material will not burn unless preheated. Avoid excessive heat as it may cause formation of vapours or mists
    - Eliminate ignition sources
- Spilled material may create a slipping hazard

Personal Protection

- 02 - <20% SCBA MUST BE WORN
- 02 = 20% Consider respirator with NIOSH approved Organic Vapour cartridges
- Wear other required PPE, as appropriate

First Aid

- **Eyes**
    - Flush eyes immediately with fresh warm water (40C-45C) for 15 minutes holding lids open
    - Get medical attention if irritation occurs and persists
- **Skin**
    - Wash contaminated skin with mild soap and water. Remove contaminated clothing
    - Get medical attention if symptoms occur and persist
- **Inhalation**
    - Move exposed person to fresh air
    - Administer oxygen therapy, as necessary and only if trained
    - WHEN OXYGEN IS IN USE, ENSURE NO SMOKING
- **Ingestion**
    - Remove dentures, if any. Wash out mouth with water. Substance has low oral toxicity
    - If swallowed, DO NOT INDUCE VOMITING. Give small quantities of water or milk to drink and seek immediate medical attention
    - If vomiting occurs, keep the head low to prevent product entering the lungs

For Further Information Consult Product MSDS

Appendix A6: **GADINIA AL 30 – EMERGENCY RESPONSE**

Spill

- Isolate area, restrict access and evacuate if necessary
- Eliminate ignition sources
- Spill may create slipping hazard
- Advise Supervisor and/or SCC # (867) 393 5324/SCC Cell. (867) 393-5355
- Request assistance
- Attempt to limit product escape routes and shut off source – IF SAFE TO DO SO
- Contain and recover using sorbent materials and/or vacuum truck

Fire

- Isolate area, restrict access and evacuate if necessary
- Summon qualified assistance
- Shut off fuel to fire, IF SAFE TO DO SO
- If qualified, extinguish with dry chemical extinguisher, CO_2, foam and/or H_20 fog. DO NOT use direct stream of water as it may spread the fire

Physical & Chemical Properties

Appearance:	Liquid. Brown colour
Odour:	Hydrocarbon odour
Flashpoint:	> + 180 C
Solubility in water:	Insoluble
Specific Gravity:	< 1 (Water = 1)
Vapour Density:	Not available

For Further Information Consult Product MSDS

Appendix A7: **TERESSO 46 – SAFETY MEASURES**

- Low order of toxicity. Excessive exposure may result in eye, skin or respiratory inhalation
  - Wear appropriate PPE
- Material will not burn unless preheated. Avoid excessive heat as it may cause formation of vapours or mists
  - Eliminate ignition sources
- Spilled material may create a slipping hazard

Personal Protection

- 02 - <20% SCBA MUST BE WORN
- 02 = 20% Consider respirator with Organic Vapour cartridges
- Wear other required PPE, as appropriate

First Aid

- **Eyes**
  - Flush eyes immediately with fresh water (40C-45C) for 15 minutes holding lids open. DO NOT USE excessively hot or cold water
  - Get medical attention if irritation occurs
- **Skin**
  - Wash contaminated skin with mild soap and water. Remove contaminated clothing
  - Get medical attention if symptoms occurs or the substances comes in contact with an open wound
- **Inhalation**
  - Move exposed person to fresh air
  - Administer oxygen therapy, as necessary and only if trained
  - WHEN OXYGEN IS IN USE, ENSURE NO SMOKING
- **Ingestion**
  - First aid is not normally required. Seek medical attention if discomfort occurs
  - Remove dentures, if any, and rinse before replacing. Rinse out mouth with water until taste of product dissipates. Substance has low oral toxicity

For Further Information Consult Product MSDS

Appendix A7: **TERESSO 46 – EMERGENCY RESPONSE**

Spill

- Isolate area, restrict access and evacuate if necessary
- Eliminate ignition sources
- Spill may create slipping hazard
- Advise Supervisor and/or SCC # (867) 393 5324/ (867) 393 5355
- Request assistance
- Attempt to limit product escape routes and shut off source – IF SAFE TO DO SO
- Contain and recover using sorbent materials and/or vacuum truck

Fire

- Isolate area, restrict access and evacuate if necessary
- Summon qualified assistance
- Shut off fuel to fire, IF SAFE TO DO SO
- If qualified, extinguish with dry chemical extinguisher, CO_2, foam and/or H_20 fog. DO NOT use direct stream of water as it may spread fire

Physical & Chemical Properties

Appearance:	Liquid. Amber in colour
Odour:	Lubricating oil odour
Flashpoint:	+ 200 C
Solubility in water:	Negligible
Specific Gravity:	< 1 (Water = 1)
Vapour Density:	> 2 (Air = 1)

For Further Information Consult Product MSDS

Appendix A8: **VARSOL – SAFETY MEASURES**

- May cause mild irritation to eyes and skin upon contact, drowsiness, lack of coordination, headache and nausea.
    - Wear appropriate PPE
- Combustible liquid. May form explosive vapours. Use in adequately ventilated area
    - Eliminate ignition sources
- Vapours heavier than air
    - Stay out of low areas and confined spaces
- May accumulate static electricity
    - Ground and bond containers during transfer

Personal Protection

- 02 - <20% SCBA MUST BE WORN
- 02 = 20% Consider respirator with Organic Vapour cartridges
- Wear other required PPE, as appropriate

First Aid

- **Eyes**
    - Flush eyes immediately with fresh warm water (40C-45C) for 15 minutes holding lids open
    - Get medical attention if irritation occurs
- **Skin**
    - Flush contaminated skin with plenty of water. Remove contaminated clothing
    - Get medical attention if symptoms occur
- **Inhalation**
    - Move exposed person to fresh air
    - Administer oxygen therapy, as necessary and only if trained
    - WHEN OXYGEN IS IN USE, ENSURE NO SMOKING
    - Get medical attention if adverse health effects persist or are severe
- **Ingestion**
    - Remove dentures, if any, and rinse with water. Rinse out mouth with water
    - Obtain medical attention if symptoms occur
    - If swallowed, DO NOT INDUCE VOMITING. Give small quantities of water or milk to drink and get immediate medical attention
    - If vomiting occurs, keep the head low to prevent product entering the lungs

For Further Information Consult Product MSDS

Appendix A8: **VARSOL – EMERGENCY RESPONSE**

Spill

- Isolate area, restrict access and evacuate if necessary
- Eliminate ignition sources
- Advise Supervisor and/or SCC # (867) 393 5324/. (867393 5355
- Request assistance
- Attempt to limit product escape routes and shut off source – IF SAFE TO DO SO
- Contain and recover using sorbent materials and/or vacuum truck

Fire

- Isolate area, restrict access and evacuate if necessary
- Summon qualified assistance
- Shut off fuel to fire, IF SAFE TO DO SO
- If qualified, extinguish with dry chemical extinguisher, CO_2, foam and/or H_20 fog. DO NOT use direct stream of water as it may spread fire

Physical & Chemical Properties

Appearance:	Clear liquid
Odour:	Petroleum distillate
Flashpoint:	> + 37.8 C (Combustible liquid)
Solubility in water:	Insoluble
Lower/Upper Flammability Limits:	1% - 13%
Vapour Density:	5 (Air = 1)

For Further Information Consult Product MSDS

Appendix A3: **VOLTESSO 35 - SAFETY MEASURES**

- May cause eye, respiratory and skin irritation. Frequent or prolonged contact may de-fat and dry the skin
    - Wear appropriate PPE
- Combustible liquid, may form explosive vapours
    - Eliminate ignition sources and monitor for combustible gases
- May accumulate static electricity
    - Ground and bond during transfers
- Vapours heavier than air
    - Stay out of low areas and confined spaces

Personal Protection

- 02 - <20% SCBA MUST BE WORN
- 02 = 20% Consider respirator with Organic Vapour cartridges
- Wear other required PPE, as appropriate

First Aid

- **Eyes**
    - Flush eyes immediately with fresh warm water (40C-45C) for at least 15 minutes holding lids open. DO NOT USE excessively hot or cold water
    - Get medical attention
- **Skin**
    - Remove contaminated clothing
    - Wash contaminated skin thoroughly with soap and warm water
    - Obtain medical attention if irritation or redness develops
    - Launder contaminated clothing before reuse
- **Inhalation**
    - Move person to fresh air
    - Administer oxygen therapy, as necessary and only if trained
    - WHEN OXYGEN IS IN USE, ENSURE NO SMOKING
- **Ingestion**
    - If swallowed, DO NOT INDUCE VOMITING and obtain immediate medical attention
    - Small amounts of materials that enter the mouth should be rinsed out until taste of substance is eliminated. Remove dentures and rinse well, if applicable

For Further Information Consult Product MSDS

Appendix A3: **VOLTESSO 35–EMERGENCY RESPONSE**

Spill

- Isolate area, restrict access and evacuate if necessary
- Eliminate ignition sources
- Advise Supervisor and/or SCC (867) 393 5324/ 867 393 5355Request assistance
- Attempt to limit escape routes and shut off source – IF SAFE TO DO SO
- Contain and recover using sorbent materials and/or vacuum truck

Fire

- Isolate area, restrict access and evacuate if necessary
- Summon qualified assistance
- Shut off fuel to fire, IF SAFE TO DO SO
- If qualified, extinguish with dry chemical extinguisher, CO2, foam and/or H20 fog. DO NOT use a direct stream of water as it may spread the fire

Physical & Chemical Properties

Appearance:	Pale Yellow, liquid
Odour:	N/D
Flashpoint:	Approximately > 145C
Solubility in water:	Negligible
Specific Gravity:	-
Vapour Density:	> N/D (Air = 1)

For Further Information Consult Product MSDS

Appendix A3: **SF6 GAS- SAFETY MEASURES**

- May cause eye, respiratory and skin irritation. Frequent or prolonged contact may de-fat and dry the skin
- Escaping gas may cause frostbite injury
    - Wear appropriate PPE
    - Eliminate ignition sources and monitor for combustible gases
- May accumulate static electricity
    - Ground and bond during transfers
- Vapours heavier than air
    - Stay out of low areas and confined spaces

Personal Protection

- General mechanical ventilation must be worn
- Ribber gloves
- ANSI approved Chemical Workers Goggles
- Coveralls

First Aid

- **Eyes**
    - Flush eyes immediately with fresh warm water (40C-45C) for at least 15 minutes holding lids open. DO NOT USE excessively hot or cold water
    - Get medical attention if pain or sensitivity to light persists
- **Skin**
    - Wash exposed area extremely thouroughly, but gently in cases of frostbite –like injury, with soap and water
- **Inhalation**
    - Move person to fresh air
    - Administer oxygen therapy, as necessary and only if trained
    - WHEN OXYGEN IS IN USE, ENSURE NO SMOKING
- **Ingestion**
    - If swallowed, DO NOT INDUCE VOMITING and obtain immediate medical attention
    - Contact MD immediately

For Further Information Consult Product MSDS

Appendix A3: **SF6 GAS –EMERGENCY RESPONSE**

Spill

- Evacuate personnel to safe areas. Wear PPE and self-contained breathing apparatus when entering area unless atmosphere is proved to be safe. Ventilate the area. Monitor oxygen level
- Stay upwind
- If possible, stop the flow of product
- Advise Supervisor and/or SCC (867) 393 5324/ 867 393 5355 Request assistance

Fire

- Isolate area, restrict access and evacuate if necessary
- Summon qualified assistance
- Shut off fuel to fire, IF SAFE TO DO SO
- If qualified, extinguish with dry chemical extinguisher, CO2, foam and/or H20 fog. DO NOT use a direct stream of water as it may spread the fire

For Further Information Consult Product MSDS

Appendix A9: **WASTE OIL – SAFETY MEASURES**

- Mixture of water, oil and lubricant additives. Concentrations of components will vary. The product is not expected to be irritating and has a low level of toxicity under normal use. Exposure most likely to occur through skin or eye contact
    - Wear appropriate PPE
    - Spill may create slipping hazard
- Material is unlikely to burn unless preheated. Spilled material may produce a slipping hazard
    - Vapour pressure will vary dependent on the composition
- It may possibly accumulate static electricity
    - Ground and bond containers during transfer

Personal Protection

- 02 - <20% SCBA MUST BE WORN
- 02 = 20% Consider respirator with Organic Vapour cartridges
- Wear other required PPE, as appropriate

First Aid

- **Eyes**
    - Flush eyes immediately with fresh warm water (40C-45C) for 15 minutes holding lids open
    - Get medical attention if irritation persists
- **Skin**
    - Wash contaminated area with plenty of mild soap and water for 15 minutes. Remove contaminated clothing
    - If irritation occurs and persists, obtain medical attention
- **Inhalation**
    - Move exposed person to fresh air. Additional First Aid treatment is not usually required
    - Administer oxygen therapy, if necessary and/or obtain medical assistance
    - WHEN OXYGEN IS IN USE, ENSURE NO SMOKING
- **Ingestion**
    - Remove dentures, if any, and rinse with water. Rinse out mouth with water
    - If swallowed, DO NOT INDUCE VOMITING. Get immediate medical attention
    - If vomiting occurs, keep the head low to prevent product entering the lungs. Obtain medical attention

For Further Information Consult Product MSDS

Appendix A9: **WASTE OIL – EMERGENCY RESPONSE**

WASTE OIL
EMERGENCY RESPONSE

Spill

- Isolate area, restrict access and evacuate if necessary
- Eliminate ignition sources though substance unlikely to ignite
- Spilled material make create a slipping hazard
- Advise Supervisor and/or SCC # (867) 393 5324/ (867) 393 5355
- Request assistance
- Attempt to limit product escape routes and shut off source – IF SAFE TO DO SO
- Contain and recover using appropriate sorbent materials and/or vacuum truck

Fire

- Isolate area, restrict access and evacuate if necessary
- Summon qualified assistance
- Shut off fuel to fire, IF SAFE TO DO SO
- If qualified, extinguish with dry chemical extinguisher, CO_2, foam and/or H_20 fog. DO NOT use a direct stream of water as it may spread fire

Physical & Chemical Properties

Appearance:	Liquid. Colour will vary depending on composition
Odour:	Hydrocarbon
Flashpoint:	Will vary depending on composition. Unlikely to burn
Solubility in water:	Insoluble
Lower/Upper Explosive Limits:	Will vary
Vapour Density:	Will vary

For Further Information Consult Product MSDS

13.0 WASTE MANAGEMENT

All equipment and/or material used in clean-up (e.g. used sorbents, oil containment materials etc.) must be disposed of in accordance with Environment Yukon requirements.

Accidental spills may produce special wastes (e.g., material with > 3% used oil) and contaminated soil. All waste disposal must comply with the *Yukon Special Waste Regulations* of the *Yukon Environment Act.*

Compliance with these regulations generally requires:

- Classification of the waste
- Packaging requirements (proper labeling and suitable storage containers)
- Transportation documentation
- All transporters must be properly trained
- Disposal in accordance with the regulations at an appropriate facility
- Spill reporting requirements must also be followed
- Waste sorbent material may not be disposed of in a landfill without prior approval from YTG Environment and the landfill operator.
- Contaminated soil must be treated and dealt with as required on a site specific basis and must comply with the requirements of the Yukon Contaminated Sites and Special Waste Regulations. At a minimum, the contractor must consider soil relocation agreement standards and obtain soil relocation permit as required.

Specific clean up requirements

Fuels and lubricants/Waste oil

After clean up, soiled sorbent materials will be placed inside an over pack or sealed metal drums and contained securely until organized special waste disposal can be coordinated.

Liquid wastes will be contained in a separate over pack or sealed metal drum.

Contaminated soils will be removed by an authorized contaminated soil receptor and transported to a land treatment facility.

All other products

All other products are to be contained in over packs or sealed metal drums separately from other products. Do not mix soiled materials. These materials are also to be picked up by Environment Yukon special wastes pick up, which occurs annually or another organized special waste disposal program at Yukon Energy. Contact the Manager of Environment for further information.

14.0 PLAN ADMINISTRATION

The following table must be filled out when changes are made to the plan.
YEC shall review the spill contingency plan annually and provide a summary of that review, including any revisions to the plan, as a component of the annual report.

Document Release and Revision History

Revision #	Revised Section/Page #	Purpose of Release: Details of Revisions/Amendments	Approved By:	Effective Date
00		New document	Director, Operations	May 2000
01	New cover page #1, #2	New cover page #1, added revision history page #2, updated contact info as required	Director, Operations	March 2004
02	Page #7, #10, #11, #12	Updated contact info as required & updated fuel day tank amounts	Director, Operations	May 2007
03	Pages 5,7, 8, and 11	Updated contact info and reporting chain as required	Manager, Environment	December 2009
04	All	Added site specific spill response procedures, updates contact information, added list of contractors for external resources, added resources at risk, updated on site spill response resources inventory. Added spill classification and clean-up plan. Added Spill Plan acknowledgement form, added sample incident report form. Added CFO to YEC reporting chain	Environmental Coordinator	June 20, 2011

Name:	Signature:	Review Date:
Director, Operations		
Leadhand Mechanical Maintenance		
Leadhand Hydro Maintenance		
Leadhand Electrical Maintenance		
EMS Manager		

Distribution List- Via YEC EMS SharePoint

This document is a Yukon Energy Environmental Management System (EMS) Environmental Work Plan (EWP), A hard copy of this document must be maintained in the operational area to which it refers (e.g., hydro plant) and replaced after the annual document review or whenever a revision is made to the plan.

References:

EMS-MP-011	Emergency Response
HS-000-E	MP-4 Incident Reporting & Investigation Procedures
HS-000-E-A	Incident Investigation Form
HS-000-E-B	Incident Reporting Form
EMS-MP-001	Environmental Management System Scope and Structural Overview

For additional copies of this plan please visit the YEC Sharepoint site
https://sp2010.yec.yk.ca/Departments/env/Spill%20Contingency%20Plans/Forms/AllItems.aspx

INDEX

1.0 EMERGENCY CONTACT INFORMATION 3
2.0 INITIAL ACTION/SAFE APPROACH GUIDELINES 5
3.0 PURPOSE AND SCOPE 6
4.0 NOTIFICATIONS 7
5.0 RESPONSE ORGANIZATION 8
6.0 SPILL SITE SAFETY PLAN 9
7.0 MATERIAL PROPERTIES 11
8.0 EQUIPMENT/SERVICES 12
9.0 CONTACT DIRECTORY 19
10.0 SITE SPECIFIC INFORMATION: WHITEHORSE 21
11.0 PROJECT SITE DESCRIPTION AND RESOURCES AT RISK ..... **Error! Bookmark not defined.**
12.0 SITE SPECIFIC SCENARIOS 22
13.0 APPENDIX A: FORMS 25
Appendix A1: **ICS 201-BRIEFING DOCUMENT** 26
Appendix A2-: **ICS 214A – INDIVIDUAL LOG** 34
Appendix A3-9: **SAFE ACTION/INITIAL ACTION CHECKLISTS BY SUBSTANCE** 37
Appendix A3: **DIESEL FUEL -SAFETY MEASURES** 39
Appendix A3: **DIESEL FUEL –EMERGENCY RESPONSE** 40
Appendix A4: **Caprinus HPE 40- SAFETY MEASURES** 41
Appendix A4: **Caprinus HPE 40- EMERGENCY RESPONSE** 42
Appendix A5: **COOLANT - SAFETY MEASURES** 43
Appendix A5: **COOLANT - EMERGENCY RESPONSE** 44
Appendix A6: **GADINIA AL 30 – SAFETY MEASURES** 45
Appendix A6: **GADINIA AL 30 – EMERGENCY RESPONSE** 46
Appendix A7: **TERESSO 46 – SAFETY MEASURES** 47
Appendix A7: **TERESSO 46 – EMERGENCY RESPONSE** 48
Appendix A8: **VARSOL – SAFETY MEASURES** 49
Appendix A8: **VARSOL – EMERGENCY RESPONSE** 50
Appendix A9: **WASTE OIL – SAFETY MEASURES** 55
Appendix A9: **WASTE OIL – EMERGENCY RESPONSE** 56
14.0 WASTE MANAGEMENT 57
15.0 PLAN ADMINISTRATION 58

LIST OF TABLES

Table 1. YUKON ENERGY OPERATIONAL LOCATIONS AND AVAILABLE EQUIPMENT 12
Table 2. Inventories/services supplied by contractor/consultant in the Whitehorse area 15
Table 6. Other Possible Scenarios 23

LIST OF FIGURES

Figure 1. Contact/Reporting Flow Chart 7

APPENDIX M – YUKON OIL AND GAS ACT

ACT TO AMEND THE OIL AND GAS ACT, 2012

(Assented to December 13, 2012)

The Commissioner of Yukon, by and with the advice and consent of the Legislative Assembly, enacts as follows

1 This *Act* amends the *Oil and Gas Act*.

Section 1 amended

2(1) **The definition of** "gas processing plant" **in subsection 1(1) is replaced with the following**

"'gas processing plant' means

(a) a plant, other than a well-head separator, treater or dehydrator, for the extraction from raw gas (as defined in the regulations) of hydrogen sulphide, helium, ethane, natural gas liquids or other substances, or

(b) a facility for the liquefaction of marketable gas (as defined in the regulations) or the storage, transfer or vaporization of liquefied natural gas; « *usine de traitement du gaz* »".

(2) **The definition of** "oil and gas facility" **in subsection 1(1) is replaced with the following**

"'oil and gas facility' means a well, a pipeline, a gas processing plant or anything designated as an oil and gas facility for the purposes of this Act by regulations under paragraph 65(1)(f) or by a direction under subsection 65(3); *« installation de pétrole et de gaz »*".

(3) **The definition of** "pipeline" **in**

LOI DE 2012 MODIFIANT LA LOI SUR LE PÉTROLE ET LE GAZ

(sanctionnée le 13 décembre 2012)

Le Commissaire du Yukon, sur l'avis et avec le consentement de l'Assemblée législative, édicte :

1 La présente loi modifie la *Loi sur le pétrole et le gaz*.

Modification de l'article 1

2(1) **Le paragraphe 1(1) est modifié en remplaçant la définition d'** « usine de traitement du gaz » **par ce qui suit :**

« "usine de traitement du gaz" S'entend :

a) soit d'une usine, à l'exception du séparateur, de l'épurateur et du déshydrateur de tête de puits, pour extraire du gaz naturel brut (tel que défini dans les règlements) de l'hydrogène sulfuré, l'hélium, l'éthane, les liquides de gaz naturel et d'autres substances;

b) soit d'une installation pour la liquéfaction de gaz commercialisable (tel que défini dans les règlements) ou l'entreposage, le transfert ou la vaporisation de gaz naturel liquéfié. "*gas processing plant*" ».

(2) **Le paragraphe 1(1) est modifié en remplaçant la définition de** « installation de pétrole et de gaz » **par ce qui suit :**

« "installation de pétrole et de gaz" Puits, pipeline, installation de traitement du gaz ou toute chose désignée à ce titre par un règlement pris en vertu de l'alinéa 65(1)f) ou par une directive donnée en vertu du paragraphe 65(3). *"oil and gas facility"* ».

(3) **Le paragraphe 1(1) est modifié en remplaçant la définition de** « pipeline » **par ce**

subsection 1(1) is replaced with the following

"'pipeline' means

(a) a pipeline located entirely within Yukon (as defined in the *Yukon Act* (Canada)) for the transportation of

(i) oil or gas or both, with or without any other commingled substance,

(ii) any product obtained from oil or gas by processing or otherwise, with or without any other commingled substance, or

(iii) any other substance intended to be used for a purpose related to an oil and gas activity; and

(b) prescribed installations and facilities associated with the pipeline,

but does not include a pipeline designated as an oil and gas facility or as part of an oil and gas facility by a direction under subsection 65(3); « *pipeline* »".

qui suit :

« "pipeline" S'entend :

a) d'un pipeline entièrement compris dans les frontières du Yukon, tel que défini dans la *Loi sur le Yukon* (Canada) et destiné au transport de ce qui suit :

(i) soit du pétrole ou du gaz, ou les deux, avec ou sans autre substance mélangée,

(ii) soit de substances dérivées du pétrole et du gaz dont le dérivé a été obtenu par quelque procédé que ce soit, avec ou sans autre substance mélangée;

(iii) soit de toute autre substance destinée à être utilisée pour des activités pétrolières et gazières;

b) des installations prévues par règlement liées au pipeline.

La présente définition ne vise pas un pipeline désigné à titre d'installation de pétrole et de gaz ou de partie d'une installation de pétrole et de gaz par une directive donnée en vertu du paragraphe 65(3). *"pipeline"* ».

(4) **The definition of** "pre-transfer well" **in subsection 1(1) is repealed.**

(4) **Le paragraphe 1(1) est modifié par abrogation de la définition de** « puits existant ».

(5) **The definition of** "security notice" **in subsection 1(1) is replaced with the following**

"'security notice' means a security notice in a form determined or approved by the Minister; « *avis de sûreté* »".

(5) **Le paragraphe 1(1) est modifié en remplaçant la définition d'** « avis de sûreté » **par ce qui suit :**

« "avis de sûreté" Avis de sûreté en la forme établie ou approuvée par le ministre. "*security notice*" ».

(6) **Paragraph (b) of the definition of** "transfer" **in subsection 1(1) is replaced with the following**

"(b) a transfer of the disposition or a specified undivided interest in the disposition made by the Minister pursuant to subsection 20.1(8) or pursuant to regulations made under paragraph 29(c);".

(6) **Le paragraphe 1(1) est modifié en remplaçant l'alinéa b) de la définition de** « transfert » **par ce qui suit :**

« b) transfert du titre d'aliénation ou d'un intérêt indivis spécifique grevant le titre d'aliénation fait par le ministre conformément au paragraphe 20.1(8) ou aux règlements pris en vertu de l'alinéa 29c); ».

(7) **The definition of** "working interest" **in**

(7) **Le paragraphe 1(1) est modifié en**

subsection 1(1) is replaced with the following

"'working interest', except in Division 4 of Part 3, means a right, or a share of a right, to recover oil or gas from a pool or part of a pool and dispose of the oil or gas so recovered, whether that right is

(a) held as an incident of ownership in fee simple of the oil or gas, or

(b) held under or derived from a lease; « *intérêt économique direct* »".

(8) **The definition of** "Yukon oil and gas lands" **in subsection 1(1) is replaced with the following**

"'Yukon oil and gas lands' means lands in Yukon in respect of which oil and gas is under the administration and control of the Commissioner; « *terres pétrolifères et gazéifères du Yukon* »".

Section 10 amended

3 In subsection 10(2)

(a) in the English version "and" **is added at the end of paragraph (a); and**

(b) paragraph (b) is repealed.

Section 13 repealed

4 Section 13 is repealed.

Section 20 amended

5 The following new subsection is added to section 20

"(6) Where two or more persons are co-holders of a disposition

(a) those co-holders are in relation to the Government jointly responsible for the obligations and liabilities arising under the disposition; and

(b) a judgment in favour of the Government

remplaçant la définition d'« intérêt économique direct » **par ce qui suit :**

« "intérêt économique direct" Sauf à la section 4 de la partie 3, un droit total ou partiel de récupérer du pétrole ou du gaz de tout ou partie d'un gisement et d'aliéner le pétrole ou le gaz ainsi récupéré, peu importe si ce droit :

a) est accessoire au domaine en fief simple sur ce pétrole ou ce gaz;

b) est détenu en vertu d'un bail ou en découle. "*working interest*" ».

(8) **Le paragraphe 1(1) est modifié en remplaçant la définition de** « terres pétrolifères et gazéifères du Yukon » **par ce qui suit :**

« "terres pétrolifères et gazéifères du Yukon" Terres du Yukon à l'égard desquelles le commissaire a la maîtrise et la gestion des ressources pétrolières et gazières. "*Yukon oil and gas lands*" ».

Modification de l'article 10

3 Le paragraphe 10(2) est modifié par :

a) insertion de « and » **à la fin de la version anglaise de l'alinéa a);**

b) abrogation de l'alinéa b).

Abrogation de l'article 13

4 L'article 13 est abrogé.

Modification de l'article 20

5 L'article 20 est modifié par adjonction du paragraphe qui suit :

« (6) Lorsque deux personnes ou plus sont cotitulaires d'un titre d'aliénation :

a) elles sont solidairement responsables à l'égard du gouvernement pour les obligations et les responsabilités conférées par le titre d'aliénation;

b) un jugement en faveur du gouvernement à

against one or more of those co-holders or a release by the Government in favour of one or more of those co-holders does not preclude the Government from obtaining judgment from another co-holder in the same or a separate proceeding."

l'encontre d'un ou plusieurs cotitulaires ou une libération accordée par le gouvernement en faveur d'un ou plusieurs cotitulaires n'empêche pas le gouvernement de faire exécuter le jugement auprès d'un autre cotitulaire dans le cadre de la même instance ou dans une instance distincte. »

Section 20.1 added

6 The following new section is added after section 20

"Legal ownership of dispositions

20.1(1) The Division Head may give a direction to the holder of a disposition to furnish to the Division Head a statement showing, as of the date of the statement, the names and addresses of the persons owning working interests in the disposition and their respective percentage shares.

(2) A direction given under subsection (1)

(a) must specify the deadline by which the statement is to be furnished; and

(b) may require that the statement

(i) be completed in accordance with any instructions contained in the direction, and

(ii) be verified in the manner provided for in the direction.

(3) If a disposition holder is given a direction under subsection (1) and the statement required by the direction is not received in the office of the Division Head by the deadline specified in the direction, the holder is liable to pay a penalty of $1000 and an additional penalty of $1000 for all or part of each subsequent month during which the failure continues.

(4) If a disposition holder furnishes a statement pursuant to a direction given under subsection (1), whether before or after the deadline specified in the direction, and the

Insertion de l'article 20.1

6 L'article qui suit est inséré après l'article 20

« Propriété des titres d'aliénation

20.1(1) Le chef de division peut ordonner au titulaire d'un titre d'aliénation de lui fournir une déclaration indiquant, en date de la déclaration, les noms et adresses des personnes qui sont propriétaires d'un intérêt économique direct dans le titre d'aliénation ainsi que le pourcentage de leur part respective.

(2) La directive donnée en vertu du paragraphe (1) :

a) contient d'une part le délai imparti pour fournir la déclaration;

b) peut d'autre part exiger que la déclaration :

(i) soit rédigée suivant les modalités prévues dans la directive,

(ii) soit vérifiée de la façon prévue dans la directive.

(3) Lorsque le titulaire d'un titre d'aliénation a reçu une directive en vertu du paragraphe (1) et que le bureau du chef de division n'a pas reçu la déclaration à l'expiration du délai imparti dans la directive, le titulaire est passible d'une amende de 1000 $ et d'une amende supplémentaire de 1000 $ pour la totalité ou une partie de chaque mois où il est toujours en défaut.

(4) Le titulaire d'un titre d'aliénation est passible d'une amende ne pouvant excéder le maximum prévu par règlement s'il a fourni une déclaration en conformité avec une directive

statement

(a) is not completed in accordance with the instructions contained in the direction;

(b) is not verified in the manner provided for in the direction; or

(c) contains inaccurate information,

the Division Head may impose on that holder a penalty not exceeding the prescribed maximum.

(5) If a statement furnished to the Division Head under this section shows

(a) that the working interest owner, or one or more of the working interest owners, is not the holder or one of the holders, as the case may be, of the disposition; or

(b) that any working interest owner who is also a co-holder of the disposition has a percentage share of the working interests in the disposition that differs from that owner's specified undivided interest in the disposition according to the records of the Department,

the Division Head may give a direction to that holder or co-holder in accordance with subsection (6).

(6) A direction under subsection (5) may, as the case requires

(a) require the holder to submit to the Division Head for registration, by the deadline specified in the direction, a registrable transfer of the disposition to the owner or owners of the working interests in the disposition; or

(b) require a co-holder of the disposition to submit to the Division Head for registration, by the deadline specified in the direction, a registrable transfer of all or part of the co-holder's specified undivided interest in the disposition to the person or persons named in the direction, so that the transfer, on being registered, will result in the transferee

donnée en vertu du paragraphe (1), que ce soit avant ou après l'expiration du délai prévu dans la directive, mais que la déclaration est entachée de l'un ou l'autre des vices suivants :

a) elle n'a pas été rédigée conformément aux modalités prévues dans la directive;

b) elle n'a pas été vérifiée de la façon prévue dans la directive;

c) elle contient des renseignements erronés.

(5) Le chef de division peut donner une directive en conformité avec le paragraphe (6) au titulaire ou au cotitulaire d'un titre d'aliénation lorsque la déclaration qui lui a été fournie en vertu présent article démontre :

a) soit que le ou les propriétaires de l'intérêt économique direct ne sont pas titulaires du titre d'aliénation;

b) soit qu'un propriétaire d'un intérêt économique direct, qui est aussi cotitulaire du titre d'aliénation, a une part exprimée en pourcentage des intérêts économiques directs dans le titre d'aliénation qui, selon les dossiers du ministère, diffère de l'intérêt indivis spécifique dans le titre d'aliénation.

(6) La directive donnée en vertu du paragraphe (5) peut, selon le cas :

a) ordonner qu'avant l'expiration du délai prévu dans la directive, le titulaire fournisse au chef de division, aux fins d'enregistrement, un transfert enregistrable du titre d'aliénation au propriétaire, ou aux propriétaires, des intérêts économiques directs dans l'aliénation;

b) ordonner qu'un codétenteur du titre d'aliénation, dans le délai prévu dans la directive, fournisse au chef de division aux fins d'enregistrement, un transfert enregistrable de tout ou partie de l'intérêt indivis spécifique du cotitulaire sur le titre d'aliénation à la ou les personnes nommées dans la directive, pour faire en sorte que le

or transferees holding specified undivided interests in the disposition that are proportionate to their respective percentage shares of the working interests in the disposition.

(7) If a holder or co-holder of a disposition to whom a direction is given under subsection (5) fails to comply with the direction by the specified deadline, the Division Head

(a) may impose on that holder or co-holder a penalty not exceeding the prescribed maximum and an additional penalty not exceeding the prescribed maximum for each subsequent month or part of a month during which the failure continues; and

(b) shall send the holder or co-holder an invoice for the penalty showing the reason for the penalty.

(8) If a penalty imposed on a holder or co-holder pursuant to subsection (7) is not paid within the period specified in the penalty invoice, the Minister, on the recommendation of the Division Head, may transfer the disposition or the specified undivided interest in the disposition in accordance with the direction under subsection (5) to the working interest owner or owners specified in the direction.

(9) Subject to the regulations

(a) a penalty imposed by subsection (3) may be waived in whole or in part by the Division Head; and

(b) a penalty imposed by or pursuant to this section may be appealed to the Minister."

Section 33 repealed

7 Section 33 is repealed.

Section 35 amended

8(1) **In subsection 35(1),** "in the location has

titre d'aliénation, lors de son transfert, soit divisé proportionnellement à la part respective exprimée en pourcentage de l'intérêt économique direct entre les destinataires du transfert.

(7) Lorsque le titulaire ou le cotitulaire d'un titre d'aliénation à qui une directive est donnée en vertu du paragraphe (5) omet de se conformer à la directive dans le délai prévu, le chef de division :

a) peut imposer au titulaire ou au cotitulaire, une amende qui ne peut excéder le maximum prescrit et une amende supplémentaire pour chaque mois ou partie de mois au cours duquel se poursuit l'omission;

b) envoie au titulaire ou au cotitulaire une facture pour l'amende en indiquant les motifs.

(8) Lorsque l'amende imposée à un titulaire ou un cotitulaire en application du paragraphe (7) n'est pas versée dans le délai prévu dans la facture de l'amende, le ministre peut, sur la recommandation du chef de division et en conformité avec le paragraphe (5), transférer le titre d'aliénation ou l'intérêt indivis spécifique dans le titre d'aliénation au détenteur ou aux détenteurs précisés dans la directive.

(9) Sous réserve des règlements :

a) le chef de division peut dispenser du paiement d'une partie ou de la totalité d'une amende imposée en vertu du paragraphe (3);

b) il peut être interjeté appel auprès du ministre de l'amende imposée en vertu du présent article. »

Abrogation de l'article 33

7 L'article 33 est abrogé.

Modification de l'article 35

8(1) **Le paragraphe 35(1) est modifié en remplaçant** « a débuté à l'emplacement » **par** « a

been begun" **is replaced with** "is commenced"**.**

(2) **In subsection 35(3),** "is begun in the location" **is replaced with** "is commenced"**.**

Section 37 amended

9 Subsection 37(3) is replaced with the following

"(3) The location of a lease issued under this section

(a) subject to paragraph (b), shall consist of those portions of the permit location within

(i) a spacing area containing one or more productive zones, or

(ii) a partial spacing area if any part of the spacing area contains one or more productive zones; and

(b) in respect of each spacing area or partial spacing area referred to in paragraph (a), shall extend down to the base of the productive zone that is stratigraphically the deepest in the spacing area."

Section 39 amended

10 Subsection 39(3) is replaced with the following

"(3) When a lease is renewed for a further term, the location of the lease at the commencement of that further term

(a) subject to paragraph (b), shall consist of those portions of the location, as it stood at the expiration of the previous term, within

(i) a spacing area containing one or more productive zones, or

(ii) a partial spacing area if any part of the spacing area contains one or more

débuté »**.**

(2) **Le paragraphe 35(3) est modifié en remplaçant** « est entrepris à l'emplacement visé » **par** « est entrepris »**.**

Modification de l'article 37

9 Le paragraphe 37(3) est remplacé par ce qui suit :

« (3) L'emplacement du bail délivré en application du présent article :

a) sous réserve de l'alinéa b), est constitué de la partie de l'emplacement visé par un permis qui se trouve dans les limites :

(i) soit d'une unité d'espacement contenant une ou plusieurs zones productives,

(ii) soit d'une unité d'espacement partielle lorsqu'elle contient une ou plusieurs zones productives;

b) à l'égard de chaque unité d'espacement ou unité d'espacement partielle visée à l'alinéa a), s'étend jusqu'à la base de la zone productive la plus profonde stratigraphiquement de cette unité d'espacement. »

Modification de l'article 39

10 Le paragraphe 39(3) est remplacé par ce qui suit :

« (3) Lorsqu'un bail est renouvelé, l'emplacement visé par celui-ci au début de la nouvelle période :

a) sous réserve de l'alinéa b), est constitué des parties de l'emplacement, dans la forme qu'il avait à la fin du bail précédent, qui se trouve dans les limites :

(i) soit d'une unité d'espacement contenant une ou plusieurs zones productives,

(ii) soit d'une unité d'espacement

productive zones; and

(b) in respect of each spacing area or partial spacing area referred to in paragraph (a), shall extend down to the base of the productive zone that is stratigraphically the deepest in the spacing area."

partielle, lorsqu'elle contient une ou plusieurs zones productives;

b) à l'égard de chaque unité d'espacement ou unité d'espacement partielle visée à l'alinéa a), s'étend jusqu'à la base de la zone productive la plus profonde stratigraphiquement de cette unité d'espacement. »

Section 42 amended

11(1) **In paragraph 42(a),** "paragraphs 41(3)(a), (b), and (c) respectively" **is replaced with** "paragraphs 41(4)(a), (b) and (c), respectively"**.**

(2) **In paragraph 42(b),** "paragraph 41(3)(d)" **is replaced with** "paragraph 41(4)(d)"**.**

Modification de l'article 42

11(1) **L'alinéa 42a) est modifié en remplaçant** « aux alinéas 41(3)a), b) et c), respectivement » **par** « aux alinéas 41(4)a), b) et c), respectivement »**.**

(2) **L'alinéa 42b) est modifié en remplaçant** « à l'alinéa 41(3)d) » **par** « à l'alinéa 41(4)d) »**.**

Section 43 amended

12(1) **In paragraph 43(a),** "paragraph 41(3)(a)" **is replaced with** "paragraph 41(4)(a)"**.**

(2) **In paragraph 43(b),** "paragraph 41(3)(b) or (c)" **is replaced with** "paragraph 41(4)(b) or (c)"**.**

(3) **In paragraph 43(c),** "paragraph 41(3)(d)" **is replaced with** "paragraph 41(4)(d)"**.**

Modification de l'article 43

12(1) **L'alinéa 43a) est modifié en remplaçant** « à l'alinéa 41(3)a) » **par** « à l'alinéa 41(4)a) »**.**

(2) **L'alinéa 43b) est modifié en remplaçant** « à l'alinéa 41(3)b) ou c) » **par** « à l'alinéa 41(4)b) ou c) »**.**

(3) **L'alinéa 43c) est modifié en remplaçant** « à l'alinéa 41(3)d) » **par** « à l'alinéa 41(4)d) »**.**

Section 46 amended

13 Paragraph 46(1)(e) is replaced with the following

"(e) respecting the determination of costs or allowances that may be deducted from amounts payable to the Government in relation to the Commissioner's royalty share of oil or gas;"**.**

Modification de l'article 46

13 L'alinéa 46(1)e) est remplacé par ce qui suit :

« e) fixer les coûts et les indemnités qui peuvent être déduits des sommes payables au gouvernement relativement à la quote-part des redevances du commissaire sur le pétrole et le gaz; »**.**

Section 50 replaced

14 Section 50 is replaced with the following

"Continuing liability following a transfer

50(1) Where a transfer is registered with respect to a disposition, a specified undivided interest in a disposition or part of the location

Remplacement de l'article 50

14 L'article 50 est remplacé par ce qui suit :

« Responsabilité maintenue suivant un transfert

50(1) Lorsqu'un transfert est enregistré relativement à un titre d'aliénation, un intérêt indivis spécifique dans un titre d'aliénation ou une partie de l'emplacement d'un titre

of a disposition

(a) any obligation or liability arising under the disposition that existed before the registration of the transfer continues, after the registration of the transfer, to run with the disposition, interest or part of the location so transferred; and

(b) the transferee and the transferor and any other co-holders of the disposition are jointly responsible for any obligation or liability referred to in paragraph (a).

(2) With respect to any obligation or liability referred to in subsection (1)

(a) any judgment in favour of the Government in respect of that obligation or liability against one or more of the persons referred to in paragraph (1)(b); or

(b) any release by the Government in respect of that obligation or liability in favour of one or more of the persons referred to in paragraph (1)(b),

does not preclude the Government from obtaining judgment against any of the other persons referred to in paragraph (1)(b) in the same or a separate proceeding."

Section 55 amended

15(1) **Subsection 55(2) is replaced with the following**

"(2) The Division Head shall register a security notice submitted for registration if the regulations respecting its registration are complied with."

(2) **In subsection 55(3),** "Subject to subsections (4) and (5), a security interest" **is replaced with** "A security interest"**.**

(3) **Subsections 55(4) and (5) are repealed.**

d'aliénation :

a) les obligations ou les responsabilités issues du titre d'aliénation qui existaient avant le transfert continuent, suivant l'enregistrement du titre d'aliénation, à être rattachées au titre d'aliénation, à l'intérêt ou à la partie de l'emplacement qui fait l'objet du transfert;

b) le destinataire du transfert, l'auteur du transfert et tout autre titulaire du titre d'aliénation sont solidairement responsables à l'égard des obligations et des responsabilités visées à l'alinéa a).

(2) Le gouvernement peut obtenir jugement relativement aux obligations ou aux responsabilités visées au paragraphe (1) contre la ou les personnes visées à l'alinéa (1)b) dans une instance distincte ou, même si jugement a déjà été rendu, dans l'une ou l'autre des instances suivantes :

a) un jugement en faveur du gouvernement relativement à cette obligation ou cette responsabilité contre une ou plusieurs des personnes visées à l'alinéa (1)b);

b) une renonciation accordée par le gouvernement relativement à cette obligation ou à cette responsabilité en faveur d'une ou plusieurs personnes visées à l'alinéa (1)b). »

Modification de l'article 55

15(1) **Le paragraphe 55(2) est remplacé par ce qui suit :**

« (2) Le chef de division enregistre l'avis de sûreté qui lui a été présenté dans la mesure où il n'y a pas eu de contravention au règlement portant sur l'enregistrement. »

(2) **Le paragraphe 55(3) est modifié en remplaçant** « Sous réserve des paragraphes (4) et (5), la sûreté » **par** « La sûreté »**.**

(3) **Les paragraphes 55(4) et (5) sont abrogés.**

Section 56 amended

16 In subsection 56(1), "prescribed by the regulations" **is repealed.**

Section 57 amended

17(1) **Subsection 57(2) is replaced with the following**

"(2) The Division Head shall register a notice submitted for registration under subsection (1) if the regulations respecting its registration are complied with."

(2) **In the English version of subsection 57(3),** "prescribed" **is repealed.**

Section 60.1 added

18 The following new section is added after section 60

"Constructive notice

60.1 The registration of a security notice, a notice referred to in subsection 56(2) or 57(1) or a certified copy of an order or judgment referred to in paragraph 58(9)(b) or subsection 60(1), constitutes actual notice of it to all persons as of the time of its registration and, in the case of a security notice, also constitutes actual notice to all persons who may serve a demand for information under section 58 in respect of the security notice of the contents of the documents described in the security notice."

Section 65 amended

19(1) **Paragraph 65(1)(d) is replaced with the following**

"(d) respecting the construction, operation, maintenance, relocation, suspension or discontinuance of operation, or abandonment of a pipeline, gas processing plant or other oil and gas facility except a well;

(d.1) respecting tariffs relating to pipeline

Modification de l'article 56

16 Le paragraphe 56(1) est modifié par abrogation de « en la forme réglementaire ».

Modification de l'article 57

17(1) **Le paragraphe 57(2) est remplacé par ce qui suit :**

« (2) Le chef de division enregistre l'avis qui lui a été présenté en vertu du paragraphe (1) dans la mesure où il n'y a pas eu de contravention au règlement portant sur l'enregistrement. »

(2) **La version anglaise du paragraphe 57(3) est modifiée par abrogation de** « prescribed ».

Insertion de l'article 60.1

18 L'article qui suit est inséré après l'article 60 :

« Présomption de connaissance

60.1 L'enregistrement d'un avis de sûreté, d'un avis visé au paragraphe 56(2) ou 57(1) ou d'une copie certifiée conforme d'une ordonnance ou d'un jugement visé au paragraphe 58(9) ou 60(1), en constitue un avis public à la date de l'enregistrement. Dans le cas d'un avis de sûreté, l'enregistrement constitue aussi un avis à quiconque peut signifier une demande de renseignement, en vertu de l'article 58, à l'égard de l'avis de sûreté visé ou du contenu des documents décrits dans l'avis de sûreté. »

Modification de l'article 65

19(1) **L'alinéa 65(1)d) est remplacé par ce qui suit :**

« d) régir la construction, l'exploitation, l'entretien, la relocalisation, la suspension, l'arrêt ou l'abandon d'un pipeline, d'une usine de traitement du gaz ou de toute autre installation de pétrole et de gaz, à l'exception d'un puits;

d.1) fixer les tarifs relatifs aux services de

transportation services and the tolls charged for those services, respecting the hearing and determination of any matter regarding those tariffs and tolls and defining "tariff" and "toll" for the purpose of those regulations;

(d.2) respecting the construction of utilities along, over or under pipelines or within prescribed distances from pipelines and the protection of pipelines from ground disturbances, and defining "utility" and "ground disturbance" for the purposes of those regulations;".

transport par pipeline et les droits de péage exigibles pour ces services, régir l'audition et le règlement de toutes questions relatives à ces tarifs et ces droits de péage et définir les termes « tarifs » et « droits de péage » pour l'application de ce règlement;

d.2) régir la construction d'installations qui se trouvent à côté, au-dessus ou au-dessous de pipelines ou à l'intérieur de distances prescrites de pipelines, ainsi que la protection des pipelines contre les nuisances au sol et définir les termes « installation » et « nuisances au sol » pour l'application de ce règlement; ».

(2) **The following new paragraphs are added to subsection 65(1)**

"(r) respecting the determination of remuneration payable to members of panels appointed pursuant to regulations under paragraph (q);

(s) respecting the imposition of pecuniary penalties for contraventions of

(i) paragraph 64(1)(a),

(ii) a provision of the regulations under this Part, if the regulations provide that its contravention is subject to the imposition of a pecuniary penalty, or

(iii) a condition of a licence."

(2) **Le paragraphe 65(1) est modifié par adjonction, après l'alinéa q), de ce qui suit :**

« r) régir l'établissement de la rémunération payable aux membres des comités nommés sous le régime des règlements pris en vertu de l'alinéa q);

s) régir l'imposition d'amendes en cas de contravention à l'une ou l'autre des dispositions suivantes :

(i) l'alinéa 64(1)a),

(ii) une disposition d'un règlement pris en vertu de la présente partie, dans la mesure où ce règlement prévoit que quiconque y contrevient est passible d'une amende,

(iii) une condition d'une licence. »

(3) **The following new subsection is added to section 65**

"(3) Despite paragraph (1)(f), the Chief Operations Officer, by a special or general direction, may designate any pipeline

(a) as an oil and gas facility for the purposes of this Act; or

(b) as part of an oil and gas facility."

(3) **L'article 65 est modifié par adjonction, après le paragraphe (2), de ce qui suit :**

« (3) Malgré l'alinéa (1)f), le délégué aux opérations peut donner une directive particulière ou générale afin de désigner un pipeline :

a) à titre d'installation de pétrole et de gaz pour l'application de la présente loi;

b) à titre de partie d'une installation de pétrole et de gaz désignée. »

Section 66 amended

20 Paragraph 66(3)(d) is replaced with the following

"(d) if the licensee fails to comply with paragraph (a), the Minister may, on giving reasonable notice and an opportunity to make representations,

(i) suspend the oil and gas activity authorized by the licence until the financial assurance required by the Minister is furnished to the Minister in accordance with this section, or

(ii) terminate the oil and gas activity authorized by the licence;".

Section 67 repealed

21 Section 67 is repealed.

Section 89 amended

22 In subsection 89(1), the definition of "working interest" **is replaced with the following**

"'working interest', in relation to a well, means a right, or a share of a right, to recover oil or gas from the pool or part of the pool in which the well is or was completed and dispose of the oil or gas so recovered, whether that right is

(a) held as an incident of ownership in fee simple of the oil or gas, or

(b) held under or derived from a lease. « *intérêt économique direct* »"

Section 105 amended

23(1) **Paragraph 105(e) is replaced with the following**

"(e) contravenes section 64, except paragraph (1)(a);

(e.1) contravenes subsection 101(3) or

Modification de l'article 66

20 L'alinéa 66(3)d) est remplacé par ce qui suit :

« d) si le titulaire de licence fait défaut de se conformer à l'alinéa a), le ministre peut, après avoir accordé un préavis raisonnable et l'occasion de présenter des observations :

(i) soit suspendre l'activité pétrolière et gazière autorisée en vertu de la licence jusqu'à ce que la preuve de solvabilité exigée par le ministre lui soit fournie en conformité avec le présent article,

(ii) mettre fin à l'activité pétrolière et gazière autorisée en vertu de la licence; ».

Abrogation de l'article 67

21 L'article 67 est abrogé.

Modification de l'article 89

22 Le paragraphe 89(1) est modifié en remplaçant la définition d'« intérêt économique direct » **par ce qui suit :**

« "intérêt économique direct" À l'égard d'un puits, s'entend d'un droit total ou partiel de récupérer le pétrole ou le gaz d'un gisement dans lequel un puits est ou était complété et d'aliéner le pétrole ou le gaz ainsi récupéré, peu importe :

a) s'il s'agit d'un droit accessoire au domaine en fief simple sur le pétrole ou le gaz;

b) s'il fait partie d'un bail ou en découle. "*working interest*" »

Modification de l'article 105

23(1) **L'alinéa 105e) est remplacé par ce qui suit :**

« e) contrevient à l'article 64, à l'exception de l'alinéa (1)a);

e.1) contrevient au paragraphe 101(3) ou à

section 103;".

(2) **In the English version of paragraph 105(1)(f),** "provides" **is replaced with** "provide".

Section 113 replaced

24 Section 113 is replaced with the following

"Recovery of pecuniary penalties

113 If a person fails to pay a pecuniary penalty imposed on that person by or pursuant to the regulations within the time prescribed by or pursuant to the regulations, the Government may recover the penalty by an action in debt and in the action the court may

(a) determine whether the person is liable for the penalty;

(b) if it is determined that the person is liable for the penalty, confirm or vary the amount of the penalty; and

(c) give judgment for the amount of the penalty so confirmed or varied."

Part 5 repealed

25 Part 5 is repealed.

l'article 103; ».

(2) **La version anglaise de l'alinéa 105(1)f) est modifiée en remplaçant** « provides » **par** « provide ».

Remplacement de l'article 113

24 L'article 113 est remplacé par ce qui suit :

« Recouvrement des amendes

113 Lorsqu'une personne omet de verser l'amende qui lui a été imposée en vertu d'un règlement dans le délai prescrit, le gouvernement peut recouvrer le montant de l'amende en engageant une action en recouvrement. Le tribunal peut alors :

a) déterminer si la personne est passible de l'amende;

b) lorsqu'il est déterminé que la personne est passible de l'amende, elle peut confirmer ou modifier le montant de l'amende;

c) rendre un jugement ordonnant le paiement de l'amende ainsi confirmée ou modifiée. »

Abrogation de la partie 5

25 La partie 5 est abrogée.

QUEEN'S PRINTER FOR THE YUKON - L'IMPRIMEUR DE LA REINE POUR LE YUKON

APPENDIX N – YUKON OIL AND GAS REGULATIONS

YUKON

CANADA

ORDER-IN-COUNCIL 2013/ 162

OIL AND GAS ACT

Pursuant to sections 10 and 65 of the *Oil and Gas Act*, the Commissioner in Executive Council orders as follows

1 The attached *Gas Processing Plant Regulation* is made.

Dated at Whitehorse, Yukon, July 31 2013.

YUKON

CANADA

DÉCRET 2013/162

LOI SUR LE PÉTROLE ET LE GAZ

Le commissaire en conseil exécutif, conformément aux articles 10 et 65 de la *Loi sur le pétrole et le gaz*, décrète :

1 Est établi le *Règlement sur les usines de traitement du gaz* paraissant en annexe.

Fait à Whitehorse, au Yukon, le 31 juillet 2013.

Commissioner of Yukon/Commissaire du Yukon

R-OGA-GPPR(ne)-13-FIN

OIL AND GAS ACT

GAS PROCESSING PLANT REGULATION

LOI SUR LE PÉTROLE ET LE GAZ

RÈGLEMENT SUR LES USINES DE TRAITEMENT DU GAZ

PART 1
GENERAL

Interpretation	1
Exemption	2
Computation of months and days	3
References to CSA-Z276	4
Compliance with CSA-Z276	5
Responsibility for compliance	6
Requirement variation or exemption	7
Prescribed programs	8
Suspension or termination of activity	9

PARTIE 1
DISPOSITIONS GÉNÉRALES

Définitions	1
Exemption	2
Calcul des mois et des jours	3
Mentions de la norme CSA-Z276	4
Respect de la norme CSA-Z276	5
Responsabilité liée au respect des exigences	6
Modification d'une exigence ou dispense	7
Programmes réglementaires	8
Suspension ou fin d'une activité	9

PART 2
LICENCES

Application for licence	10
Documents supporting application	11
Management system	12
Safety program	13
Environmental protection program	14
Non-destructive examination program	15
Issuance of licence	16
Conditions of licence	17
Amendment of licence	18

PARTIE 2
LICENCES

Demande de licence	10
Documents à l'appui d'une demande	11
Système de gestion	12
Programme de sécurité	13
Programme de protection de l'environnement	14
Programme d'examen non destructif	15
Délivrance de licence	16
Conditions de la licence	17
Modification de la licence	18

PART 3
CONSTRUCTION

Designs and specifications	19
Construction contract requirements	20
Construction requirements	21
Safety requirements	22
Pressure testing	23

PARTIE 3
CONSTRUCTION

Conception et construction	19
Exigences applicables aux contrats de construction	20
Exigences en matière de construction	21
Exigences en matière de sécurité	22
Essais sous pression	23

PART 4
OPERATION AND MAINTENANCE

Approval to operate	24
Application for operation approval	25
Operations and maintenance manual	26
Emergency procedures manual	27
Staffing plan and training program	28
Visitors	29
Operations	30
Inspections	31
External audits	32

PARTIE 4
EXPLOITATION ET ENTRETIEN

Approbation de l'exploitation	24
Demande d'approbation de l'exploitation	25
Manuel d'exploitation et d'entretien	26
Manuel des mesures d'urgence	27
Plan de dotation et programme de formation	28
Visiteurs	29
Exploitation	30
Inspections	31
Vérifications externes	32

PART 5
PHYSICAL AND OPERATIONAL CHANGES

Direction for operational changes 33
Alteration 34
Suspension 35
Deactivation 36
Reactivation 37
Abandonment 38

PART 6
RECORDS AND REPORTING

Retention of records 39
Throughput records 40
Monthly throughput reports 41
Measurement standards 42
Incidents and near-misses 43
Press releases and press conferences 44

PART 7
PENALTIES

Penalties owing to Government 45

DIVISION 1
REPORTING-RELATED PENALTIES

Definitions for Division 1 46
Report or notification on request 47
Penalties for late submission or notification 48
Penalties related to non-compliant reporting 49
Penalty invoice 50

DIVISION *2*
ADMINISTRATIVE PENALTIES

Definitions for Division 2 51
Penalties for Schedule contraventions 52
Penalties for contraventions of licence conditions 53
Procedures related to findings 54
Imposition of administrative penalty 55
Notice of administrative penalty 56

SCHEDULE

CONTRAVENTIONS AND MAXIMUM ADMINISTRATIVE PENALTIES

PARTIE 5
MODIFICATIONS PHYSIQUES ET OPÉRATIONNELLES

Directive exigeant des modifications opérationnelles 33
Modification 34
Suspension 35
Mise hors service 36
Remise en service 37
Abandon 38

PARTIE 6
DOSSIERS ET RAPPORTS

Conservation des dossiers 39
Dossiers relatifs au débit 40
Rapport mensuel sur le débit 41
Normes de mesure 42
Incidents et quasi-incidents 43
Communiqués de presse et conférences de presse 44

PARTIE 7
PEINES

Amendes payables au gouvernement 45

SECTION 1
PEINES LIÉES AUX RAPPORTS

Définitions applicables à la section 1 46
Rapport ou avis sur demande 47
Peines pour les retards 48
Peines découlant de la présentation non conforme de rapports 49
Facture pour l'amende 50

SECTION 2
SANCTIONS ADMINISTRATIVES

Définitions applicables à la section 2 51
Peines pour contraventions prévues à l'annexe 52
Peines pour contraventions aux conditions d'une licence 53
Procédures découlant des conclusions 54
Imposition d'une sanction administrative 55
Avis de sanction administrative 56

ANNEXE

CONTRAVENTIONS ET AMENDES MAXIMALES SANCTIONS ADMINISTRATIVES

$500,000 maximum	1	Amende maximale de 500 000 $	1
$250,000 maximum	2	Amende maximale de 250 000 $	2
$100,000 maximum	3	Amende maximale de 100 000 $	3

PART 1

GENERAL

Interpretation

1 In this Regulation

"abandonment", in relation to a processing plant or LNG facility or part of a plant or facility, means the decommissioning of the plant or facility or the part in accordance with this Regulation; « *abandon* »

"authorized activity", in relation to a processing plant or LNG facility, means the construction, operation, relocation, alteration, suspension of operation, deactivation, reactivation or abandonment of all or part of the plant or facility, or any other activity related to the plant or facility; « *activité autorisée* »

"CSA-Z276" means the standard published by the Canadian Standards Association, numbered Z276-11 and entitled *Liquefied Natural Gas (LNG) – Production, Storage and Handling*; « *norme CSA-Z276* »

"deactivate", in relation to a processing plant or LNG facility, means to discontinue all or part of the plant or facility from service in accordance with this Regulation to render it inoperable but to maintain it for later reactivation; « *mettre hors service* »

"environment" means

(a) air, land and water,

(b) all organic and inorganic matter and living organisms, including biodiversity within and among species,

(c) ecosystems and ecological relationships,

(d) buildings, structures, roads, facilities, works and artifacts,

(e) all social and economic conditions affecting community life, and

PARTIE 1

DISPOSITIONS GÉNÉRALES

Définitions

1 Les définitions qui suivent s'appliquent au présent règlement.

« abandon » À l'égard d'une usine de traitement ou d'une installation de GNL ou d'une partie de l'une ou l'autre, s'entend de la désaffectation de l'usine, de l'installation, ou de la partie en conformité avec le présent règlement. *"abandonment"*

« activité autorisée » À l'égard d'une usine de traitement ou d'une installation de GNL, s'entend de la construction, de l'exploitation, du déménagement, de modifications, de la suspension de l'exploitation, de la mise hors service, de la remise en service ou de l'abandon de la totalité ou d'une partie de l'usine ou de l'installation ou encore, de toute autre activité liée à l'usine ou l'installation. *"authorized activity"*

« approbation d'exploitation » Approbation donnée par le délégué aux opérations conformément au paragraphe 24(1) relativement à une usine de traitement ou une installation de GNL. *"operation approval"*

« environnement » S'entend :

a) de l'air, du sol et de l'eau;

b) de toutes les matières organiques et inorganiques, ainsi que des êtres vivants, y compris la biodiversité au sein des espèces et entre elles;

c) des écosystèmes et des liens écologiques;

d) des bâtiments, des structures, des routes, des installations, des constructions et des artefacts;

e) de l'ensemble des conditions sociales et économiques ayant un impact sur la vie communautaire;

(f) the inter-relationships between or among any of the factors in paragraphs (a) to (e); « *environnement* »

"escape", in relation to a processing plant or LNG facility, means a discharge or emission of a fluid from the plant or facility, other than one authorized pursuant to this Regulation or directions of the Chief Operations Officer; « *rejet* »

"incident", in relation to a processing plant or LNG facility, means

(a) an event occurring in the course of an authorized activity that causes or results in

(i) the death of a person,

(ii) an injury to an employee that prevents that employee from reporting for work or from effectively performing all the duties connected with the employee's regular work on any day subsequent to the day on which the injury occurred, whether or not that subsequent day was a working day for that employee,

(iii) a fire or explosion,

(iv) the escape of a fluid from the plant or facility, or

(v) the impairment of any part of the plant or facility that is critical to environmental protection; or

(b) an event occurring in the course of an authorized activity that results in a missing person; « *incident* »

"licence" means a licence for a processing plant or for an LNG facility, as the case requires; « *licence* »

"LNG" means liquefied natural gas; « *GNL* »

"LNG facility" or "facility" means a facility for the liquefaction of marketable gas or the storage, transfer or vaporization of liquefied natural gas; « *installation de GNL* »

f) des interdépendances entre les éléments énumérés aux alinéas a) à e). "*environment*"

« exploiter » S'entend notamment de réparer et entretenir. "*operate*"

« gaz commercialisable » Mélange gazeux principalement composé de méthane qui satisfait aux spécifications pour être utilisé comme combustible domestique, commercial ou industriel ou comme matière première industrielle dans une exploitation industrielle ou de fabrication. "*marketable gas*"

« gaz en solution » Composante gazeuse du pétrole, y compris le gaz dégagé. "*solution gas*"

« gaz naturel brut » Gaz naturel et gaz naturel dissous. "*raw gas*"

« GNL » Gaz naturel liquéfié. "*LNG*"

« incident » À l'égard d'une usine de traitement ou d'une installation de GNL, s'entend :

a) soit d'un évènement qui survient dans le cadre d'une activité autorisée et qui cause ou provoque :

(i) la mort d'une personne,

(ii) une blessure à un employé qui l'empêche de se présenter au travail ou de s'acquitter de façon efficace de toutes ses fonctions dans le cadre de son travail normal à quelque date que ce soit après avoir été blessé, même si cette date ne correspondait pas à une journée de travail pour cet employé,

(iii) un incendie ou une explosion,

(iv) la fuite d'un fluide de l'usine ou de l'installation,

(v) une défaillance d'une composante de l'usine ou de l'installation qui est essentielle pour la protection de l'environnement;

b) soit d'un évènement survenant dans le cadre d'une activité autorisée à l'issu duquel

"marketable gas" means a gaseous mixture that consists mainly of methane and meets specifications for use as a domestic, commercial or industrial fuel or as a raw material in an industrial or manufacturing operation; « *gaz commercialisable* »

"near-miss" means an event described in paragraph (a) of the definition of "incident" that would likely have occurred in the absence of particular circumstances; « *quasi-incident* »

"operate" includes repair and maintain; « *exploiter* »

"operation approval" means an approval issued by the Chief Operations Officer pursuant to subsection 24(1) in respect of a processing plant or LNG facility; « *approbation d'exploitation* »

"prescribed program" means

(a) a program or plan referred to in paragraphs 11(1)(d) to (h), or

(b) a plan, manual or program referred to in paragraphs 25(2)(b) to (e); « *programme réglementaire* »

"processing plant" or "plant" means a plant, other than a well-head separator, treater or dehydrator, for the extraction from raw gas of hydrogen sulphide, helium, ethane, natural gas liquids or other substances; « *usine de traitement* »

"raw gas" means natural gas and solution gas; « *gaz naturel brut* »

"reactivate" means to return a processing plant or LNG facility to service in accordance with section 37; « *remettre en service* »

"safety" means the protection of individuals or property from danger, risk or injury; « *sécurité* »

"solution gas" means the gaseous component of petroleum and includes evolved gas. « *gaz en solution* »

une personne est portée disparue. "*incident*"

« installation de GNL » ou « installation » Installation de liquéfaction de gaz commercialisable ou d'entreposage, de transfert ou de vaporisation de gaz naturel liquéfié. "*LNG facility*"

« licence » Licence d'exploitation d'une usine de traitement ou d'une installation de GNL, selon le cas. "*licence*"

« mettre hors service » À l'égard d'une usine de traitement ou d'une installation de GNL, s'entend de suspendre la totalité ou une partie de ses activités en conformité avec le présent règlement en vue de la rendre inutilisable, mais de l'entretenir pour sa remise en service éventuelle. "*deactivate*"

« norme CSA-Z276 » La norme publiée par l'Association canadienne de normalisation, numérotée Z276-11 et intitulée *Gaz naturel liquéfié (GNL) – Production, stockage et manutention*. "*CSA-Z276*"

« programme réglementaire » S'entend :

a) soit d'un programme visé aux alinéas 11(1)d) à h);

b) soit d'un plan, d'un manuel ou d'un programme visé aux alinéas 25(2)b) à e). "*prescribed program*"

« quasi-incident » Évènement décrit à l'alinéa a) de la définition d'« incident » qui serait vraisemblablement survenu sans des circonstances particulières. "*near-miss*"

« rejet » À l'égard d'une usine de traitement ou d'une installation de GNL, s'entend du déversement ou de l'émission d'un fluide de l'usine ou de l'installation, à l'exception de ceux autorisés en vertu du présent règlement ou de directives du délégué aux opérations. "*escape*"

« remettre en service » Remise en service d'une usine de traitement ou d'une installation de GNL en conformité avec l'article 37. "*reactivate*"

« sécurité » La protection des individus ou des

biens contre les dangers, les risques ou les blessures. *"safety"*

« usine de traitement » ou « usine » Usine, autre qu'un séparateur, un épurateur ou un déshydrateur de tête de puits, pour extraire le sulfure d'hydrogène, l'hélium, l'éthane, les liquides de gaz naturel ou d'autres substances du gaz naturel brut. *"processing plant"*

Exemption

2 The processing plant in the Kotaneelee Field used for the processing of raw gas recovered from wells in that Field is exempted from paragraph 64(1)(d) of the Act until the date on which the exemption expires, as specified in a notice given by the Chief Operations Officer to the operator of the plant.

Exemption

2 L'usine de traitement située dans le champ de Kotaneelee, exploitée pour le traitement du gaz brut recouvré des puits de ce champ, est exemptée de l'application de l'alinéa 64(1)d) de la Loi jusqu'à la date d'expiration de l'exemption, fixée dans un avis donné par le délégué aux opérations à l'exploitant de l'usine.

Computation of months and days

3(1) When a reference is made in this Regulation to a month, whether by its name or not, the reference shall be construed as the period beginning at 7:00 a.m. Pacific Standard Time on the first day of the month and ending immediately before 7:00 a.m. Pacific Standard Time on the first day of the next month.

(2) When a reference is made in this Regulation to a day, whether specified or not, the reference shall be construed as the period beginning at 7:00 a.m. Pacific Standard Time on that day and ending immediately before 7:00 a.m. Pacific Standard Time on the next day.

(3) The Chief Operations Officer may, by a direction, allow licensees to compute months or days in a manner different from the manner provided for in subsections (1) and (2).

Calcul des mois et des jours

3(1) La mention d'un mois dans le présent règlement, qu'il soit ou non mentionné par son nom, vaut mention de la période débutant à 7 h, heure normale du Pacifique, le premier jour du mois et se terminant immédiatement avant 7 h, heure normale du Pacifique, le premier jour du mois suivant.

(2) La mention d'un jour dans le présent règlement, qu'il soit ou non précisé lequel, vaut mention de la période débutant à 7 h, heure normale du Pacifique, ce même jour et se terminant immédiatement avant 7 h, heure normale du Pacifique, le jour suivant.

(3) Le délégué aux opérations peut, par directive, permettre aux titulaires d'une licence de calculer les mois ou les jours d'une façon différente de celle prévue aux paragraphes (1) et (2).

References to CSA-Z276

4(1) For the purposes of this Regulation, a reference to CSA-Z276 shall be read as a reference to

(a) CSA-Z276, as amended from time to time; or

(b) if a new edition of CSA-Z276 is published,

Mentions de la norme CSA-Z276

4(1) Pour l'application du présent règlement, la mention de la norme CSA-Z276 vaut mention :

a) de la norme CSA-Z276, dans ses versions successives;

b) si une nouvelle édition de la norme CSA-Z276

that new edition, as amended from time to time.

(2) If an Annex to CSA-Z276 indicates that it is written in mandatory language to facilitate its adoption by regulatory authorities, then, for the purposes of this Regulation, the Annex is adopted as part of CSA-Z276 and as additional requirements to that standard.

(3) A reference in CSA-Z276 to an "operating company" or to a person or company operating an LNG facility shall, for the purposes of this Regulation, be read as a reference to the licensee of the LNG facility.

Compliance with CSA-Z276

5(1) Subject to this Regulation, the licensee of an LNG facility must comply with CSA-Z276 in all matters relating to the LNG facility.

(2) If there is a conflict or inconsistency between a provision of CSA-Z276 and a provision of this Regulation, a licence or an order or direction of the Chief Operations Officer, the latter provision prevails.

(3) If CSA-Z276 is amended or replaced resulting in a new requirement or the replacement of a requirement with one more stringent, the Chief Operations Officer may, by a direction, postpone the need for compliance with the new or replacement requirement for a specified period or until the occurrence of a specified event.

Responsibility for compliance

6(1) If a provision of this Regulation, a licence or an order or direction of the Chief Operations Officer imposes a duty on the licensee of a processing plant or LNG facility to comply with a particular requirement, then, for the purposes of this Regulation, the licensee is responsible for the acts and omissions of its agents and contractors in relation to compliance with that requirement.

est publiée, de cette nouvelle édition, dans ses versions successives.

(2) Lorsqu'une annexe de la norme CSA-Z276 précise qu'elle est rédigée en langage obligatoire pour faciliter son adoption par les organismes de réglementation, cette annexe est adoptée à titre de partie de la norme CSA-Z276 et d'exigences s'ajoutant à cette norme.

(3) Pour l'application du présent règlement, la mention dans la norme CSA-Z276 de « compagnie d'exploitation » ou d'une personne ou société exploitant une installation de GNL vaut mention du titulaire de la licence d'exploitation de l'installation de GNL.

Respect de la norme CSA-Z276

5(1) Sous réserve des autres dispositions du présent règlement, le titulaire d'une licence d'installation de GNL doit respecter la norme CSA-Z276 pour toutes les questions relatives à l'installation de GNL.

(2) En cas d'incompatibilité, une disposition du présent règlement, d'une licence ou d'un ordre ou d'une directive du délégué aux opérations l'emporte sur une disposition de la norme CSA-Z276.

(3) Lorsque la modification ou le remplacement de la norme CSA-Z276 crée une nouvelle exigence ou en remplace une par une exigence plus contraignante, le délégué aux opérations peut, par directive, reporter l'obligation de respecter cette nouvelle exigence pour une période déterminée ou jusqu'à la survenance d'un évènement particulier.

Responsabilité liée au respect des exigences

6(1) Lorsqu'une disposition du présent règlement, une licence ou encore, un ordre ou une directive du délégué aux opérations, prévoit que le titulaire de la licence d'exploitation d'une usine de traitement ou d'une installation de GNL doit respecter une exigence particulière, le titulaire de licence engage sa responsabilité, pour l'application du présent règlement, pour les actes et omissions de ses mandataires et entrepreneurs relativement

(2) If a provision of this Regulation, a licence or an order or direction of the Chief Operations Officer imposes a requirement in relation to a processing plant or any LNG facility or any part of it without specifying the person responsible for complying with the requirement, then, for the purposes of this Regulation, the licensee is responsible for complying with the requirement.

(3) The licensee of a processing plant or LNG facility must comply with

(a) orders issued to the licensee pursuant to this Regulation by the Chief Operations Officer in respect of the plant or facility; and

(b) directions of the Chief Operations Officer that apply to the plant or facility.

(4) If any matter pertaining to a processing plant or LNG facility is not provided for in this Regulation, the licence, the directions of the Chief Operations Officer or CSA-Z276, the licensee must, in relation to that matter, follow the best prevailing industry practice for cold climate conditions.

Requirement variation or exemption

7(1) Subject to subsection (2), the Chief Operations Officer may, by a direction,

(a) vary any of the requirements of this Regulation or any directions of the Chief Operations Officer in respect of all or any class of processing plants or of a particular processing plant;

(b) vary any of the requirements of this Regulation, CSA-Z276 or any directions of the Chief Operations Officer in respect of all or any class of LNG facilities or a particular LNG facility; or

(c) exempt a licensee or any other person from

au respect de cette exigence.

(2) Lorsqu'une disposition du présent règlement, une licence ou encore, un ordre ou une directive du délégué aux opérations, impose une exigence liée à l'usine de traitement ou l'installation de GNL, ou une partie de celle-ci, sans préciser qui est responsable du respect de cette exigence, le titulaire de licence est responsable du respect de cette exigence pour l'application du présent règlement.

(3) Le titulaire de la licence d'exploitation d'une usine de traitement ou d'une installation de GNL doit se conformer :

a) d'une part, aux ordres qui lui sont donnés en application du présent règlement par le délégué aux opérations à l'égard de l'usine ou de l'installation;

b) d'autre part, aux directives du délégué aux opérations qui s'appliquent à l'usine ou à l'installation.

(4) Lorsque le présent règlement, la licence, les directives du délégué aux opérations ou la norme CSA-Z276 ne traitent pas d'une question relative à une usine de traitement ou une installation de GNL, le titulaire doit suivre les pratiques exemplaires courantes de l'industrie pour un climat froid.

Modification d'une exigence ou dispense

7(1) Sous réserve du paragraphe (2), le délégué aux opérations peut, dans une directive :

a) modifier une exigence du présent règlement ou une de ces directives relativement à toutes les usines de traitement, à une catégorie de celles-ci ou à une usine de traitement en particulier;

b) modifier une exigence du présent règlement, de la norme CSA-Z276 ou une de ces directives relativement à toutes les installations de GNL, à une catégorie de celles-ci ou à une installation de GNL en particulier;

c) accorder une dispense à un titulaire de licence

compliance with any requirements referred to in paragraph (a) or (b).

(2) A direction may not be issued under subsection (1) unless the Chief Operations Officer is satisfied that the variation or exemption is warranted

(a) for reasons related to safety or environmental protection or to changes in technology or legislation;

(b) despite subsection 5(2), to make a provision of this Regulation inapplicable to LNG facilities where the provision is inappropriate in relation to LNG facilities or where the application of a comparable provision of CSA-Z276 is preferable;

(c) to resolve an inconsistency or conflict between a requirement referred to in subsection (1) and a requirement under any other legislation in force in Yukon; or

(d) to avoid a duplication of regulatory oversight in relation to a requirement referred to in subsection (1) without prejudicially affecting the objectives of the requirement.

(3) The Chief Operations Officer shall publish each direction issued under subsection (1) by posting it on the Department's Internet website as soon as practicable but within five working days following its issue and make it available for inspection during normal business hours at the offices of the Chief Operations Officer.

Prescribed programs

8(1) The licensee of a processing plant or LNG facility must implement and comply with each of the licensee's prescribed programs for the plant or facility.

(2) The licensee of a plant or facility must, with respect to each of the prescribed programs for the

ou à une autre personne relativement à une exigence visée aux alinéas a) ou b).

(2) Une directive ne peut être donnée en vertu du paragraphe (1) que si le délégué aux opérations est convaincu que la modification ou la dispense est justifiée :

a) pour des motifs liés à la sécurité ou à la protection de l'environnement ou à des changements d'ordre technologique ou législatif;

b) malgré le paragraphe 5(2), pour rendre une disposition du présent règlement inapplicable aux installations de GNL lorsque la disposition n'est pas adéquate à l'égard des installations de GNL ou lorsque l'application d'une disposition comparable de la norme CSA-Z276 est préférable;

c) pour pallier à une incompatibilité ou un conflit entre une exigence visée au paragraphe (1) et une exigence prévue dans un autre texte de loi en vigueur au Yukon;

d) pour éviter la duplication des régimes réglementaires de surveillance relativement à une exigence visée au paragraphe (1), sans nuire aux objectifs de l'exigence.

(3) Le délégué aux opérations publie chaque directive émise en vertu du paragraphe (1) en l'affichant dès que possible sur le site Internet du ministère, et au plus tard cinq jours ouvrables suivant son émission, et la rend disponible pour consultation pendant les heures normales d'ouverture dans les bureaux du délégué aux opérations.

Programmes réglementaires

8(1) Le titulaire de la licence d'exploitation d'une usine de traitement ou d'une installation de GNL doit mettre en œuvre chacun des programmes réglementaires pour l'usine ou l'installation et s'y conformer.

(2) Le titulaire de la licence d'exploitation d'une usine ou d'une installation doit, relativement à chaque programme réglementaire pour l'usine ou

plant or facility,

(a) regularly monitor the program to ensure it reflects current best industry practices and amend it as necessary to incorporate any changes relevant to the program;

(b) in the case of an LNG facility, amend it as necessary to have it reflect any changes made to any provisions of CSA-Z276 that are relevant to the program; and

(c) submit to the Chief Operations Officer each amendment to or replacement of the program, within 30 days after the amendment or replacement comes into effect.

(3) The licensee of a plant or facility must

(a) audit each of its prescribed programs for the plant or facility on a regular basis in accordance with the directions of the Chief Operations Officer;

(b) prepare a report respecting each audit in accordance with the directions of the Chief Operations Officer; and

(c) submit a copy of the report to the Chief Operations Officer within 30 days after completion of the audit.

(4) The Chief Operations Officer, on being satisfied that it is necessary to do so because of concerns related to safety, environmental protection or resource conservation and after consultation with the licensee, may, by a notice to the licensee,

(a) amend a prescribed program of the licensee with respect to its plant or facility or any part of it; and

(b) direct the licensee to

(i) incorporate the amendment in its prescribed program within the period

l'installation :

a) effectuer une surveillance régulière du programme pour veiller à ce qu'il reflète les pratiques exemplaires de l'industrie et le modifier si nécessaire pour y incorporer des modifications pertinentes;

b) dans le cas d'une installation de GNL, le modifier au besoin pour qu'il tienne compte de modifications à des dispositions de la norme CSA-Z276 qui sont pertinentes aux fins du programme;

c) présenter au délégué aux opérations chaque modification apportée au programme ou le remplacement de celui-ci au plus tard 30 jours après l'entrée en vigueur de la modification ou du remplacement.

(3) Le titulaire de la licence d'exploitation d'une usine ou d'une installation doit, à la fois :

a) procéder de façon régulière à des vérifications de chacun des programmes pour l'usine ou l'installation en conformité avec les directives du délégué aux opérations;

b) préparer un rapport pour chaque vérification en conformité avec les directives du délégué aux opérations;

c) présenter une copie du rapport au délégué aux opérations au plus tard 30 jours après la fin de la vérification.

(4) Lorsqu'il est convaincu qu'il est nécessaire de le faire en raison de préoccupations liées à la sécurité, la protection de l'environnement ou la conservation des ressources, le délégué aux opérations peut, après consultation avec le titulaire de licence, en lui donnant un avis :

a) modifier un programme réglementaire du titulaire de licence relatif à son usine ou son installation ou toute partie de celle-ci;

b) ordonner au titulaire de licence :

(i) d'incorporer la modification dans son programme réglementaire avant la fin de la

specified in the notice, and

(ii) submit to the Chief Operations Officer, within the period specified in the notice, the prescribed program with the amendments incorporated in it.

(5) An amendment to a prescribed program made pursuant to subsection (4) is effective on the date the notice is given to the licensee and binds the licensee as of that date.

(6) Copies of the licensee's current versions of the following prescribed programs must be kept at its plant or facility in a location where they are readily accessible to all personnel engaged in the operation of the plant or facility

(a) the safety program and environmental protection program referred to in paragraphs 11(1)(d) and (e) respectively; and

(b) the operations and maintenance manual and emergency procedures manual referred to in paragraphs 25(2)(b) and (c) respectively.

Suspension or termination of activity

9(1) Subject to subsection (2), the Chief Operations Officer may, by a notice, order the licensee of a processing plant or LNG facility to suspend or terminate, in accordance with the order, any authorized activity related to the plant or facility.

(2) The Chief Operations Officer may make an order under subsection (1) only on being satisfied that

(a) the order is necessary to enable the Chief Operations Officer to exercise any powers under section 96 of the Act in relation to the plant or facility or the conduct of the authorized activity, including powers exercised following an incident or near-miss;

période prévue dans l'avis,

(ii) de fournir au délégué aux opérations, avant la fin de la période prévue dans l'avis, le programme réglementaire incorporant les modifications.

(5) Une modification à un programme réglementaire effectuée en application du paragraphe (4) prend effet à la date à laquelle l'avis est donné au titulaire de licence et lie ce dernier à compter de cette date.

(6) Des copies à jour des programmes réglementaires suivants du titulaire de licence doivent être conservées à son usine ou son installation à un endroit où ils sont facilement accessibles pour tous les membres du personnel participant à l'exploitation de l'usine ou l'installation :

a) les programmes de sécurité et de protection de l'environnement respectivement visés aux alinéas 11(1)d) et e);

b) les manuels d'exploitation et d'entretien et de mesures d'urgence respectivement visés aux alinéas 25(2)b) et c).

Suspension ou fin d'une activité

9(1) Sous réserve du paragraphe (2), le délégué aux opérations peut, en donnant un avis, ordonner au titulaire de la licence d'exploitation d'une usine de traitement ou d'une installation de GNL de suspendre ou de mettre fin, en conformité avec l'ordre donné, à une activité autorisée liée à l'usine ou l'installation.

(2) Le délégué aux opérations ne peut donner un ordre en application du paragraphe (1) que s'il est convaincu :

a) que l'ordre est nécessaire pour permettre au délégué aux opérations d'exercer des attributions en application de l'article 96 de la Loi relativement à l'usine ou l'installation ou à la poursuite d'une activité autorisée, y compris des attributions exercées suivant un incident ou un quasi-incident;

(b) the licensee has ceased to be eligible to be the holder of a licence; or

(c) the licensee has failed to perform its obligations under the Act, this Regulation, its licence or an order or direction of the Chief Operations Officer by reason of insufficient financial resources or otherwise.

(3) The Chief Operations Officer may revoke an order under subsection (1) on being satisfied that the grounds on which the order was based no longer exist or that the failure of compliance has been remedied.

PART 2

LICENCES

Application for licence

10(1) An application for a licence for a processing plant or LNG facility and the supporting documentation must be prepared and submitted to the Chief Operations Officer in accordance with the directions of the Chief Operations Officer.

(2) The Chief Operations Officer may issue directions to the applicant for a licence respecting requirements for

(a) the publication of, or the distribution of copies of, either its application or a notice of its application; and

(b) the modes of publication or distribution of its application or the notice and, in the case of a notice, its content.

(3) The Chief Operations Officer, on receiving an application for a licence,

(a) shall make the application available for public inspection during normal business hours at the offices of the Chief Operations Officer and post on the Department's Internet website a notice stating that the application is so available; and

(b) may publish or distribute copies of the

b) que le titulaire de licence n'est plus admissible à être détenteur d'une licence;

c) que le titulaire de licence ne s'est pas acquitté de ses obligations prévues dans la Loi, le présent règlement, sa licence ou un ordre ou une directive du délégué aux opérations en raison de ressources financières insuffisantes ou pour d'autres motifs.

(3) Le délégué aux opérations peut révoquer un ordre donné en vertu du paragraphe (1) lorsqu'il est convaincu que les motifs pour lesquels l'ordre a été donné n'existent plus ou qu'il a été remédié au défaut.

PARTIE 2

LICENCES

Demande de licence

10(1) La demande de licence d'exploitation d'une usine de traitement ou d'une installation de GNL et les documents à l'appui doivent être préparés et présentés au délégué aux opérations en conformité avec les directives de ce dernier.

(2) Le délégué aux opérations peut émettre des directives à l'auteur d'une demande de licence concernant les exigences applicables à ce qui suit :

a) la publication ou la distribution de sa demande ou d'un avis de sa demande;

b) les modes de publication et de distribution de sa demande ou de l'avis, y compris son contenu dans le cas de ce dernier.

(3) Sur réception d'une demande de licence, le délégué aux opérations :

a) doit rendre la demande accessible au public pour consultation pendant les heures normales d'ouverture dans les bureaux du délégué aux opérations et publier un avis sur le site Internet du ministère précisant qu'il est ainsi possible de consulter la demande;

b) peut publier ou distribuer des copies de la

application or the notice.

Documents supporting application

11(1) An application for a licence for a processing plant or LNG facility must contain or be accompanied by the following

(a) a map showing the proposed location of the site for the plant or facility;

(b) a report showing the information required by subsection 20(1) of the *Oil and Gas Licence Administration Regulations;*

(c) a statement certifying that the applicant has in place a management system that meets the requirements of section 12;

(d) a safety program that meets the requirements of section 13;

(e) an environmental protection program that meets the requirements of section 14;

(f) a program for non-destructive examination of welded joints that meets the requirements of section 15;

(g) a quality control and quality assurance program for the components of the plant or facility;

(h) a plan for the eventual abandonment of the plant or facility and for reclaiming the site of the plant or facility after the abandonment;

(i) a statement identifying the contractor for the construction of the plant or facility;

(j) in the case of a processing plant, a description of the processing facilities and control system, including the flow system, the flow calculation procedure and the flow allocation procedure that will be used for measurement purposes;

(k) information respecting any proposed flaring

demande ou de l'avis.

Documents à l'appui d'une demande

11(1) Une demande de licence d'exploitation d'une usine de traitement ou d'une installation de GNL doit contenir les documents suivants ou être accompagnée de ceux-ci :

a) une carte montrant l'emplacement proposé du site de l'usine ou de l'installation;

b) un rapport contenant les renseignements exigés en vertu du paragraphe 20(1) du *Règlement sur l'administration des licences de pétrole et de gaz;*

c) une déclaration attestant que l'auteur de la demande a mis sur pied un système de gestion qui respecte les exigences prévues à l'article 12;

d) un programme de sécurité qui respecte les exigences prévues à l'article 13;

e) un programme de protection de l'environnement qui respecte les exigences prévues à l'article 14;

f) un programme de vérification par examen non destructif des joints soudés qui respecte les exigences prévues à l'article 15;

g) un programme de contrôle et d'assurance de la qualité pour les pièces d'équipement de l'usine ou de l'installation;

h) un plan pour l'abandon éventuel de l'usine ou de l'installation et la remise en état du site de l'usine ou de l'installation après son abandon;

i) une déclaration identifiant l'entrepreneur désigné pour la construction de l'usine ou de l'installation;

j) dans le cas d'une usine de traitement, une description des installations de traitement et des systèmes de contrôle, notamment du système d'écoulement, de la méthode de calcul du débit et de la méthode de répartition du débit qui seront utilisés comme outils de mesure;

k) des renseignements sur le brûlage envisagé de

or venting of raw gas, marketable gas or other gaseous substances; and

(l) any other information or document required by a direction of the Chief Operations Officer.

(2) An application need not be accompanied by a prescribed program if

(a) the applicant has previously submitted the program to the Chief Operations Officer in support of an application for a different licence; and

(b) the program is still current and appropriate for the plant or facility.

(3) An application for a licence may contain or be accompanied by

(a) a request for a direction under section 7 respecting the proposed plant or facility, and an explanation of and justification for the direction so requested; or

(b) an application under subsection 65(3) of the Act to have a pipeline designated as part of the plant or facility if the route of the pipeline is shown on the map referred to in paragraph (1)(a).

(4) After receiving an application for a licence, the Chief Operations Officer may request the applicant to provide any additional information or documents relevant to the application.

Management system

12(1) The management system referred to in paragraph 11(1)(c) must be an effective system for the processing plant or LNG facility that integrates operations and technical systems with the management of financial and human resources to ensure compliance with the Act and this Regulation.

gaz naturel brut, de gaz commercialisable ou d'une autre substance gazeuse ou sur leur rejet dans l'atmosphère;

l) les autres renseignements ou documents exigés dans une directive du délégué aux opérations.

(2) Une demande n'a pas à être accompagnée d'un programme réglementaire lorsque les conditions suivantes sont réunies :

a) l'auteur de la demande a déjà présenté le programme au délégué aux opérations à l'appui d'une demande relative à une autre licence;

b) le programme est à jour et adéquat pour l'usine ou l'installation.

(3) Une demande de licence peut contenir ou être accompagnée de ce qui suit :

a) soit une demande visant à obtenir une directive en vertu de l'article 7 relative à un projet d'usine ou d'installation, accompagnée d'explications et de motifs pour la directive demandée;

b) soit une demande en application du paragraphe 65(3) de la Loi pour qu'un pipeline soit désigné à titre de partie d'une usine ou d'une installation, si le tracé du pipeline est indiqué sur la carte visée à l'alinéa (1)a).

(4) Après avoir reçu une demande de licence, le délégué aux opérations peut demander à l'auteur de la demande de fournir des renseignements ou des documents supplémentaires pertinents aux fins de la demande.

Système de gestion

12(1) Le système de gestion visé à l'alinéa 11(1)c) doit être un système efficace pour l'usine de traitement ou l'installation de GNL, qui intègre les systèmes opérationnels et techniques et la gestion des ressources humaines et financières, pour veiller à l'observation de la Loi et du présent règlement.

(2) The management system must include

(a) the policies on which the system is based;

(b) the processes for setting goals for the improvement of safety, environmental protection and waste prevention;

(c) the processes for identifying hazards and for evaluating and managing the associated risks;

(d) the processes for ensuring that personnel are trained and competent to perform their duties;

(e) the processes for ensuring and maintaining the integrity of the plant or facility and equipment necessary to ensure safety, environmental protection and waste prevention;

(f) the processes for the internal reporting and analysis of hazards, minor injuries, incidents and near-misses and for taking corrective actions to prevent their recurrence;

(g) the documents describing all management system processes and the processes for making personnel aware of their roles and responsibilities with respect to them;

(h) the processes for ensuring that all documents associated with the system are current, valid and have been approved by the appropriate level of authority;

(i) the processes for conducting periodic reviews or audits of the system and for taking corrective actions if reviews or audits identify areas of non-conformance with the system;

(j) the arrangements for coordinating the management and operations of the proposed activity among the licensee, its contractors and subcontractors and others, as applicable; and

(2) Le système de gestion doit comprendre :

a) un énoncé des politiques qui en constituent le fondement;

b) des processus permettant de fixer des objectifs en vue d'améliorer la sécurité, la protection de l'environnement et la prévention du gaspillage;

c) des processus permettant de repérer les dangers et d'évaluer et maîtriser les risques connexes;

d) des processus permettant de veiller à ce que les membres du personnel soient formés et disposent des compétences nécessaires pour remplir leurs fonctions;

e) des processus permettant de garantir et de préserver l'intégrité de l'usine ou de l'installation et du matériel nécessaire à la sécurité, la protection de l'environnement et la prévention du gaspillage;

f) des processus permettant de signaler à l'interne et d'analyser les dangers, les blessures sans gravité, les incidents et les quasi-incidents, et de prendre des mesures correctives pour empêcher que ceux-ci ne se reproduisent;

g) des documents exposant tous les processus du système de gestion et les processus visant à faire connaître aux membres du personnel leurs rôles et leurs responsabilités à cet égard;

h) des processus permettant de veiller à ce que tous les documents relatifs au système soient à jour, valides et approuvés par le niveau décisionnel compétent;

i) des processus permettant d'effectuer des examens ou des vérifications périodiques du système et d'appliquer des mesures correctives lorsque les examens ou vérifications révèlent des manquements au système de gestion;

j) des dispositions concernant la coordination des fonctions de gestion et d'exploitation de l'activité proposée entre le titulaire de licence, les entrepreneurs, les sous-entrepreneurs et les

(k) the name and position of the person accountable for the establishment and maintenance of the system and of the person responsible for implementing it.

(3) The management system documentation must be controlled and set out in a logical and systematic fashion to allow for ease of understanding and efficient implementation.

(4) The management system must correspond to the size, nature and complexity of the plant or facility and the hazards and risks associated with its operation.

(5) A licensee must, on request, submit to the Chief Operations Officer evidence to substantiate that its management system is in compliance with this section.

Safety program

13 The safety program referred to in paragraph 11(1)(d) must provide for measures to anticipate, prevent, manage and mitigate potentially dangerous conditions at the licensee's processing plant or LNG facility during authorized activities and exposure to those conditions, and must also contain

(a) a summary of and references to the management system that demonstrate how it will be applied to the plant or facility and how the duties set out in this Regulation with regard to safety will be fulfilled;

(b) a summary of the studies undertaken to identify hazards and to evaluate safety risks related to the plant or facility;

(c) a description of the hazards that were identified and the results of the risk evaluation;

(d) a summary of the measures to avoid, prevent, reduce and manage safety risks;

(e) a summary of the measures to inform personnel at the site of the plant or facility of

autres, selon le cas;

k) le nom et le titre du poste de la personne qui doit répondre de l'élaboration et de la tenue du système et de la personne chargée de sa mise en œuvre.

(3) La documentation relative au système de gestion doit être contrôlée et présentée d'une manière logique et systématique pour en faciliter la compréhension et pour assurer l'application efficace du système.

(4) Le système de gestion doit être adapté à l'importance, à la nature et à la complexité de l'usine ou de l'installation, ainsi qu'aux dangers et aux risques liés à son exploitation.

(5) Sur demande, le titulaire de licence doit présenter au délégué aux opérations des éléments de preuve établissant que son système de gestion respecte le présent article.

Programme de sécurité

13 Le programme de sécurité visé à l'alinéa 11(1)d) doit prévoir des mesures pour anticiper, prévenir, gérer et atténuer les conditions potentiellement dangereuses et l'exposition à celles-ci à l'usine de traitement ou l'installation de GNL du titulaire de licence pendant les activités autorisées. Il doit aussi contenir :

a) un résumé du système de gestion et les renvois à celui-ci qui démontrent sa mise en œuvre à l'usine ou l'installation et de quelle façon il permettra de se conformer aux obligations prévues dans le présent règlement en matière de sécurité;

b) un résumé des études réalisées pour cerner les dangers et évaluer les risques pour la sécurité liés à l'usine ou l'installation;

c) une description des dangers cernés et des résultats de l'évaluation des risques;

d) un résumé des mesures pour éviter, prévenir, réduire et contrôler les risques pour la sécurité;

e) un résumé des mesures pour informer les membres du personnel sur le site de l'usine ou

the practices and procedures to be followed for their safety, including those to be followed during periods of escalated risk arising in the course of pressure testing and acceptance procedures;

(f) emergency response procedures to mitigate the effects of any reasonably foreseeable event that might compromise safety;

(g) provisions respecting liaison with any relevant municipal, territorial or federal emergency response agencies for the purpose of coordinating the program's emergency response procedures with theirs;

(h) a list of all structures, equipment and systems critical to safety and a summary of the system in place for their inspection, testing and maintenance;

(i) a description of the organizational structure for the plant or facility which shows the contact information and position of the person accountable for the safety program and of the person responsible for implementing it; and

(j) a description of the arrangements for monitoring compliance with the program and for measuring performance in relation to its objectives.

Environmental protection program

14 The environmental protection program referred to in paragraph 11(1)(e) must set out the procedures, practices, resources and monitoring necessary to manage hazards to authorized activities related to the processing plant or LNG facility and protect the environment from those activities, and must include

(a) a summary of and references to the management system that demonstrate how it will be applied to the plant or facility and how the duties set out in this Regulation with regard to environmental protection will be fulfilled;

de l'installation des pratiques et des procédures à suivre pour leur sécurité, notamment celles qui doivent être suivies pendant les périodes de risques accrus lors des procédures d'essais sous pression et d'acceptation d'un appareil;

f) les procédures d'intervention d'urgence en vue de réduire les conséquences de tout évènement normalement prévisible qui pourrait compromettre la sécurité;

g) des dispositions prévoyant des mesures de coordination du plan d'intervention d'urgence prévu dans le programme avec tout plan d'intervention d'urgence municipal, territorial ou fédéral;

h) une liste des structures, du matériel et des systèmes qui sont essentiels à la sécurité, ainsi qu'un résumé du système en place pour veiller à leur inspection, essai et entretien;

i) une description de la structure organisationnelle pour l'usine ou l'installation qui indique le titre du poste et les coordonnées de la personne qui répond du plan de sécurité et de celle chargée de sa mise en œuvre;

j) une description des mécanismes de surveillance nécessaires pour veiller à ce que le programme soit mis en œuvre et pour évaluer le rendement au regard de ses objectifs.

Programme de protection de l'environnement

14 Le programme de protection de l'environnement visé à l'alinéa 11(1)e) doit prévoir les procédures, les pratiques, les ressources et les mesures de surveillance nécessaires pour gérer les dangers pour les activités autorisées liées à l'usine de traitement ou l'installation de GNL et protéger l'environnement de ces activités. Il doit en outre comporter :

a) un résumé du système de gestion et les renvois à celui-ci qui démontrent sa mise en œuvre dans l'usine ou l'installation et de quelle façon le système de gestion permettra de se conformer aux obligations prévues dans le présent règlement en matière de protection de

(b) a summary of the studies undertaken to identify environmental hazards and to evaluate environmental risks relating to the plant or facility;

(c) a description of the hazards that were identified and the results of the risk evaluation;

(d) a summary of the measures to avoid, prevent, reduce and manage environmental risks;

(e) a list of all structures, equipment and systems critical to environmental protection and a summary of the systems in place for their inspection, testing and maintenance;

(f) emergency response procedures to mitigate the effects of any reasonably foreseeable event that might compromise environmental protection;

(g) provisions respecting liaison with any relevant municipal, territorial or federal emergency response agencies for the purpose of co-ordinating the program's emergency response procedures with theirs;

(h) a description of the organizational structure for the plant or facility which shows the contact information and position of the person accountable for the environmental protection program and of the person responsible for implementing it;

(i) the procedures for the selection, evaluation and use of chemical substances including process chemicals;

(j) a description of equipment and procedures for the treatment, handling and disposal of waste material;

(k) a description of all discharge streams and limits for any discharge into the natural environment including any waste material;

l'environnement;

b) un résumé des études réalisées pour cerner les dangers pour l'environnement et évaluer les risques pour l'environnement liés à l'usine ou l'installation;

c) une description des dangers cernés et les résultats de l'évaluation des risques;

d) un résumé des mesures prévues pour éviter, prévenir, réduire et contrôler les risques pour l'environnement;

e) une liste des structures, du matériel, de l'équipement et des systèmes essentiels à la protection de l'environnement, ainsi qu'un résumé des systèmes en place pour leur inspection, essai et entretien;

f) les procédures d'intervention d'urgence en vue de réduire les conséquences de tout évènement normalement prévisible qui pourrait compromettre la protection de l'environnement;

g) des dispositions prévoyant des mesures de coordination du plan d'intervention d'urgence prévu dans le programme avec tout plan d'intervention d'urgence des entités municipales, territoriales ou fédérales;

h) une description de la structure organisationnelle pour l'usine ou l'installation qui indique le titre du poste et les coordonnées de la personne qui répond du plan de protection de l'environnement et de celle chargée de sa mise en œuvre;

i) les procédures de sélection, d'évaluation et d'utilisation des substances chimiques, y compris les produits chimiques utilisés pour les procédés;

j) une description de l'équipement et des procédés de traitement, de manutention et d'élimination des déchets;

k) une description de toutes les voies d'évacuation et des limites relatives à toute évacuation dans le milieu naturel, y compris

(l) a description of the system for monitoring compliance with the discharge limits identified in paragraph (k), including the sampling and analytical program to determine if those discharges are within the specified limits; and

(m) a description of the arrangements for monitoring compliance with the program and for measuring performance in relation to its objectives.

Non-destructive examination program

15(1) Subject to subsection (2), the licensee's program for non-destructive examination referred to in paragraph 11(1)(f) must include a requirement for the mandatory non-destructive examination of the entire weld volume of all piping welds in the licensee's processing plant or LNG facility.

(2) The program may be modified to allow for examination of fewer than all piping welds if the program is based on a documented risk analysis.

(3) A licensee must not implement a modified program referred to in subsection (2) unless the program and the risk analysis on which it is based are approved by the Chief Operations Officer.

(4) Visual examination is not an acceptable form of non-destructive examination for the purposes of this section.

Issuance of licence

16(1) The Chief Operations Officer may approve or disapprove an application for a licence.

(2) Two or more LNG facilities on the same site may be included in the same licence.

(3) If the application is approved, the licence shall be issued by the Chief Operations Officer.

(4) A licence shall

(a) contain or incorporate by reference a map

l'évacuation des déchets;

l) une description du système de contrôle des limites d'évacuation visées à l'alinéa k), y compris du programme d'échantillonnage et d'analyse servant à vérifier si les limites sont respectées;

m) une description des mesures prises pour contrôler la conformité au plan et en évaluer le rendement au regard de ses objectifs.

Programme d'examen non destructif

15(1) Sous réserve du paragraphe (2), le programme de vérification par examen non destructif du titulaire de licence visé à l'alinéa 11(1)f) doit exiger un examen non destructif du volume de toutes les soudures de conduite examinées dans l'usine de traitement ou l'installation de GNL du titulaire de licence.

(2) Le programme peut être modifié pour permettre que l'examen ne porte pas sur l'ensemble des soudures de conduite s'il est fondé sur une analyse des risques documentée.

(3) Un titulaire de licence ne peut mettre en œuvre ou modifier un programme visé au paragraphe (2) que si le programme et l'analyse des risques sur lesquels il est fondé ont été approuvés par le délégué aux opérations.

(4) Pour l'application du présent article, l'inspection visuelle ne constitue pas une forme acceptable d'examen non destructif.

Délivrance de licence

16(1) Le délégué aux opérations peut approuver ou rejeter une demande de licence.

(2) La même licence peut viser deux installations de GNL ou plus sur le même site.

(3) Si la demande est approuvée, la licence est délivrée par le délégué aux opérations.

(4) Une licence doit, à la fois :

a) contenir ou incorporer par renvoi, une carte

showing the site of the plant or facility; and

(b) in the case of a processing plant, state the type of processing to occur at the plant and the maximum throughput capacity of the plant.

Conditions of licence

17(1) A licence for a processing plant or LNG facility is subject to the following conditions:

(a) construction of the plant or facility must be commenced and completed by the respective dates shown in the licence;

(b) the contractor identified in the application for the licence must be used in the construction of the plant or facility unless otherwise approved by the Chief Operations Officer; and

(c) the plant or facility must be constructed in accordance with the licence, any conditions imposed by the Chief Operations Officer in relation to the licence and any applicable directions of the Chief Operations Officer.

(2) The Chief Operations Officer may, by a notice to the licensee, advance or extend either date referred to in paragraph (1)(a).

(3) If the Chief Operations Officer is satisfied that construction of a processing plant or LNG facility is not substantially commenced by the commencement date specified in the licence, or by any extension of that date granted pursuant to subsection (2), the Chief Operations Officer may, by a notice to the licensee, cancel the licence for the plant or facility.

(4) When a condition of a licence incorporates by reference any provisions of the application for the licence or of any other supporting document, those provisions are considered to be contained in the licence for the purposes of this Regulation.

sur laquelle apparaît le site de l'usine ou de l'installation;

b) dans le cas d'une usine de traitement, énoncer le type de traitement qui sera effectué à l'usine et la capacité maximale de débit de l'usine.

Conditions de la licence

17(1) La licence d'exploitation d'une usine de traitement ou d'une installation de GNL est assujettie aux conditions suivantes :

a) les travaux de construction de l'usine ou de l'installation doivent débuter et se terminer aux dates prévues sur la licence;

b) à moins d'approbation contraire du délégué aux opérations, il doit être fait appel à l'entrepreneur désigné dans la demande de licence pour la construction de l'usine ou de l'installation;

c) l'usine ou l'installation doit être construite en conformité avec la licence, les conditions imposées par le délégué aux opérations à l'égard de la licence et les directives applicables du délégué aux opérations.

(2) Le délégué aux opérations peut, en donnant avis au titulaire de licence, devancer ou reporter l'une ou l'autre des dates visées à l'alinéa (1)a).

(3) Si le délégué aux opérations est convaincu que les travaux de construction d'une usine de traitement ou d'une installation de GNL n'ont pas débuté de façon substantielle à la date fixée dans la licence pour le début des travaux, ou au terme de la prolongation accordée en vertu du paragraphe (2), le délégué aux opérations peut, en donnant avis au titulaire de licence, annuler la licence d'exploitation de l'usine ou de l'installation.

(4) Lorsqu'une condition d'une licence incorpore par renvoi des dispositions de la demande de licence ou de documents à l'appui, ces dispositions sont réputées faire partie de la licence pour l'application du présent règlement.

Amendment of licence

18(1) The Chief Operations Officer may amend a licence

(a) on application by the licensee; or

(b) after consultation with the licensee, if the amendment is made

(i) for a reason related to safety, environmental protection or changes in technology or legislation, or

(ii) to correct an error or resolve an ambiguity.

(2) The Chief Operations Officer may, instead of amending a licence, reissue the licence with the amendments incorporated in it.

PART 3

CONSTRUCTION

Designs and specifications

19(1) A licensee must not commence construction of its processing plant or LNG facility unless

(a) it has submitted to the Chief Operations Officer detailed designs of the plant or facility and the specifications for its components;

(b) the Chief Operations Officer notifies the licensee that it may commence construction subject to any changes in the designs or specifications considered by the Chief Operations Officer to be necessary for reasons related to safety or environmental protection; and

(c) any changes required pursuant to paragraph (b) have been submitted to the Chief Operations Officer.

(2) A plant or facility must be constructed in accordance with the designs and specifications

Modification de la licence

18(1) Le délégué aux opérations peut modifier une licence :

a) soit à la demande du titulaire de licence;

b) soit après consultation avec le titulaire de licence, si la modification est effectuée :

(i) pour des motifs liés à la sécurité, la protection de l'environnement ou des modifications d'ordre technologique ou législatif,

(ii) pour corriger une erreur ou remédier à une ambiguïté.

(2) Plutôt que de modifier la licence, le délégué aux opérations peut délivrer la licence de nouveau en y incorporant les modifications.

PARTIE 3

CONSTRUCTION

Conception et construction

19(1) Le titulaire de licence ne peut commencer les travaux de construction de l'usine de traitement ou de l'installation de GNL que si les conditions suivantes sont réunies :

a) il a soumis les dessins détaillés de l'usine ou de l'installation au délégué aux opérations, de même que les exigences techniques de ses pièces d'équipement;

b) le délégué aux opérations avise le titulaire de licence qu'il peut commencer les travaux de construction, sous réserve des modifications aux dessins ou aux exigences techniques que le délégué aux opérations estime nécessaires pour des raisons de sécurité ou de protection de l'environnement;

c) les modifications exigées en vertu de l'alinéa b) ont été soumises au délégué aux opérations.

(2) Une usine ou une installation doit être construite en conformité avec les dessins et les

submitted pursuant to paragraph (1)(a), as modified by any changes submitted pursuant to paragraph (1)(c).

Construction contract requirements

20(1) If a licensee contracts for the provision of services in respect of the construction of its processing plant or LNG facility, the contract must

(a) require the contractor and the contractor's subcontractors to be fully informed of and comply with the requirements of this Regulation applicable to the construction of the plant or facility and of the licensee's prescribed programs to the extent that they are applicable to the construction of the plant or facility; and

(b) impose on the licensee an obligation to appoint as its agent an individual having sufficient expertise, knowledge and training to carry out competently the duties described in subsection (2).

(2) An agent appointed under paragraph (1)(b) has a duty to regularly monitor the construction of the plant or facility and to halt any activity in circumstances where, in the agent's judgment, the activity is creating a hazard to the public or personnel at the construction site or to the environment.

Construction requirements

21 A processing plant or LNG facility must comply with the following

(a) each tank, bullet, sphere or other container that contains any fluid, other than fresh water, must be designed, constructed and maintained to restrict and contain fluids and to minimize the risk to the safety of persons and to the environment in the event of an escape of the fluid;

(b) equipment that has a source of ignition with

exigences techniques fournies en application de l'alinéa (1)a), avec les modifications apportées conformément à l'alinéa (1)c).

Exigences applicables aux contrats de construction

20(1) Si le titulaire de licence accorde un contrat pour la construction de son usine de traitement ou son installation de GNL, le contrat doit, à la fois :

a) exiger que l'entrepreneur et ses sous-traitants connaissent parfaitement et respectent les exigences du présent règlement applicables à la construction de l'usine ou de l'installation, ainsi que les programmes réglementaires du titulaire de licence, dans la mesure où ils s'appliquent à la construction de l'usine ou de l'installation;

b) imposer l'obligation au titulaire de licence de nommer à titre de mandataire, un individu possédant une expertise, des connaissances et une formation suffisantes pour s'acquitter de façon compétente des fonctions décrites au paragraphe (2).

(2) Le mandataire nommé en vertu de l'alinéa (1)b) a le devoir de surveiller de façon régulière les travaux de construction de l'usine ou de l'installation et de faire cesser une activité dans les circonstances où, selon le mandataire, cette activité crée un danger pour le public ou les membres du personnel sur le site de construction ou pour l'environnement.

Exigences en matière de construction

21 Les exigences suivantes doivent être respectées pour une usine de traitement ou une installation de GNL :

a) chaque réservoir, qu'il soit de type cylindrique, sphérique ou autre, contenant un fluide autre que de l'eau fraîche doit être conçu, construit et entretenu pour retenir et contenir le fluide, et pour réduire au minimum les risques pour la sécurité des personnes et l'environnement en cas de rejet involontaire du fluide;

b) aucun appareil ayant une source d'allumage

which a gaseous fluid at explosive levels may come into contact must not be located in the same building as any process vessel or other source of flammable fluid, unless

(i) air intake flues are located outside the building in an area where any flammable fluid is unlikely to be present,

(ii) relief valves, burst plates and other sources of flammable fluids are vented from the building or discharged to a flare header, or other location that is environmentally safe,

(iii) a specific risk analysis is conducted to determine what active, reactive or passive safety devices should be installed on that equipment and the licensee installs those devices, and

(iv) the building is cross-ventilated;

avec laquelle des fluides à l'état gazeux en concentration explosive peuvent entrer en contact ne doit être situé dans le même bâtiment qu'une cuve de traitement ou toute autre source de fluides inflammables, sauf si les exigences suivantes sont remplies :

(i) les conduits de prise d'air sont situés à l'extérieur du bâtiment, dans une zone où la présence de fluide inflammable est improbable,

(ii) les soupapes de sûreté, les plaques de rupture et les autres sources de fluides inflammables sont ventilées vers l'extérieur du bâtiment ou vers un collecteur de torche ou un autre emplacement sécuritaire sur le plan environnemental,

(iii) une analyse spécifique des risques est réalisée afin de déterminer quels dispositifs de sécurité actifs, réactifs ou passifs doivent être installés sur cet appareil et le titulaire de licence installe ces dispositifs,

(iv) le bâtiment fait l'objet d'une ventilation transversale;

(c) all process vessels and equipment from which any flammable fluid or toxic substance may escape must be safely vented to a flare header or to other locations where the protection of the environment and the safety of persons are maintained;

c) toutes les cuves de traitement et tout l'équipement pouvant rejeter des fluides inflammables ou des substances toxiques doivent être ventilés de manière sûre vers un collecteur de torche ou tout autre emplacement où la protection de l'environnement et la sécurité des personnes sont assurées;

(d) all flare headers must be equipped with a means by which the flame from the flare header is prevented from entering into piping or vessels from which the flammable fluid is being released;

d) tous les collecteurs de torche doivent être munis d'un dispositif qui empêche la flamme des collecteurs de torche d'entrer dans la tuyauterie sous pression ou dans une cuve d'où le fluide inflammable est rejeté;

(e) hydrocarbon storage vessels or buildings used for the processing of raw gas must be equipped with reliable fire suppression systems appropriate to the risk that the vessels or buildings pose to the safety of persons or to the environment if the vessels or buildings catch fire or come into contact with fire; and

e) les cuves de stockage des hydrocarbures ou les bâtiments utilisés pour le traitement du gaz brut doivent être équipés de systèmes d'extinction des incendies fiables convenant au risque que les cuves ou les bâtiments posent pour la sécurité des personnes ou de l'environnement s'ils s'enflamment ou entrent en contact avec une flamme;

(f) all pressure-relief piping and systems must be designed and constructed so that an emergency pressure release does not create a detriment to property or to the environment or a hazard to the safety of persons.

Safety requirements

22 A licensee must equip its processing plant or LNG facility with

(a) a source of emergency power;

(b) systems that are appropriate to its buildings or structures and that are designed for the detection of

(i) explosive and flammable gases,

(ii) toxic or noxious gases, and

(iii) fire, the products of combustion or temperature rise; and

(c) alarm devices that are

(i) located where they can be heard or seen from all locations within the plant or facility, and

(ii) designed in a manner that will allow a timely warning of danger to be given to persons in the plant or facility or in the vicinity of the plant or facility in order to permit safe evacuation or actions to control the danger.

Pressure testing

23(1) The licensee must, at least seven days before the test begins, notify the Chief Operations Officer of

(a) the pressure testing of all or any part of its processing plant or LNG facility; and

(b) the pressure testing of any component of the

f) toute la tuyauterie et tous les systèmes de décharge doivent être conçus et construits de façon à ce que le rejet de décompression d'urgence ne soit pas dommageable à la propriété ou à l'environnement et ne comporte aucun danger pour la sécurité des personnes.

Exigences en matière de sécurité

22 Le titulaire de licence veille à ce que l'usine de traitement ou l'installation de GNL soit munie de ce qui suit :

a) une source d'alimentation électrique d'urgence;

b) des systèmes convenant à ses bâtiments ou à ses structures conçus pour détecter :

(i) les gaz inflammables et explosifs;

(ii) les gaz toxiques ou nocifs;

(iii) les incendies, les produits de combustion ou l'augmentation de la température;

c) de dispositifs d'alarme qui, à la fois :

(i) sont situés là où ils peuvent être entendus ou vus de partout dans l'usine ou l'installation,

(ii) sont conçus de telle manière qu'ils avertissent à temps d'un danger les personnes se trouvant à l'usine ou l'installation, ou à proximité de celle-ci, afin de permettre l'évacuation en toute sécurité ou la prise de mesures pour maîtriser le danger.

Essais sous pression

23(1) Le titulaire de licence doit, au moins sept jours avant le début des essais, aviser le délégué aux opérations de ce qui suit :

a) les essais sous pression de la totalité ou d'une partie de l'usine de traitement ou de l'installation de GNL;

b) les essais sous pression d'une pièce

plant or facility, before or after it is installed in the plant or facility.

(2) If the licensee engages a contractor to perform a pressure test referred to in subsection (1), the contractor must be independent of

(a) the contractor who constructed the plant or facility;

(b) any person who participated in the fabrication of any of the components to be tested; and

(c) a contractor or lessee referred to in paragraph 24(2)(b).

(3) If a pressure test referred to in subsection (1) is performed by the licensee, it must be performed under the direct supervision of an agent engaged by the licensee for the purpose who

(a) has sufficient expertise, knowledge and training to perform it competently; and

(b) is independent of

(i) any contractor who constructed the plant or facility or any person who participated in the fabrication of any of the components to be tested,

(ii) a contractor or lessee referred to in paragraph 24(2)(b), and

(iii) any contractor engaged to perform the test.

(4) All logs, charts and other records of a pressure test referred to in subsection (1) must be dated and signed by the person supervising the test.

d'équipement, avant ou après son installation dans l'usine ou l'installation.

(2) Lorsque le titulaire de licence engage un entrepreneur pour effectuer les tests visés au paragraphe (1), l'entrepreneur ne doit avoir aucun lien avec les personnes suivantes :

a) l'entrepreneur qui a construit l'usine ou l'installation;

b) une personne ayant participé à la fabrication d'une pièce d'équipement qui doit faire l'objet des essais;

c) l'entrepreneur ou le locataire visé à l'alinéa 24(2)b).

(3) Si les essais sous pression visés au paragraphe (1) sont effectués par le titulaire de licence, ils doivent être effectués sous la supervision immédiate d'un mandataire engagé à cette fin qui, à la fois :

a) dispose d'une expertise, de connaissances et d'une formation suffisantes pour le faire de façon compétente;

b) n'a aucun lien avec l'une ou l'autre des personnes suivantes :

(i) un entrepreneur qui a participé à la construction de l'usine ou de l'installation ou une personne qui a participé à la fabrication d'une pièce d'équipement devant faire l'objet d'essais,

(ii) l'entrepreneur ou le locataire visé à l'alinéa 24(2)b),

(iii) un entrepreneur engagé pour effectuer les essais.

(4) Les registres, les graphiques et les autres documents relatifs à l'essai sous pression visé au paragraphe (1) doivent être signés et datés par la personne qui supervise l'essai.

PART 4

OPERATION AND MAINTENANCE

Approval to operate

24(1) A licensee of a processing plant or LNG facility must not commence the operation of the plant or facility unless the Chief Operations Officer has issued an approval authorizing the licensee to do so.

(2) No person shall operate a plant or facility other than

(a) the licensee; or

(b) with the approval of the Chief Operations Officer, a corporation

(i) engaged by the licensee to operate the plant or facility on its behalf, or

(ii) to which the plant or facility is leased by the licensee.

Application for operation approval

25(1) An application for an operation approval and the supporting documentation must be prepared and submitted to the Chief Operations Officer in accordance with the directions of the Chief Operations Officer.

(2) An application for an operation approval must contain or be accompanied by

(a) a report containing the results of the pressure testing of the processing plant or LNG facility;

(b) an operations and maintenance manual that meets the requirements of section 26;

(c) an emergency procedures manual that meets the requirements of section 27;

(d) a staffing plan that meets the requirements

PARTIE 4

EXPLOITATION ET ENTRETIEN

Approbation de l'exploitation

24(1) Le titulaire de la licence d'exploitation d'une usine de traitement ou d'une installation de GNL ne peut débuter l'exploitation de l'usine ou l'installation sans avoir obtenu l'autorisation préalable du délégué aux opérations.

(2) Il est interdit à quiconque d'exploiter une usine ou une installation, sauf :

a) pour le titulaire de licence;

b) avec l'approbation du délégué aux opérations, pour une société qui se trouve dans l'une ou l'autre des situations suivantes :

(i) elle a été engagée par le titulaire de licence pour exploiter l'usine ou l'installation en son nom,

(ii) l'usine ou l'installation lui a été louée par le titulaire de licence.

Demande d'approbation de l'exploitation

25(1) La demande d'approbation de l'exploitation et les documents à l'appui doivent être préparés et présentés au délégué aux opérations en conformité avec les directives de ce dernier.

(2) La demande d'approbation de l'exploitation doit contenir les documents suivants ou être accompagnée de ceux-ci :

a) un rapport contenant les résultats des essais sous pression à l'usine de traitement ou l'installation de GNL;

b) un manuel de l'exploitation et de l'entretien qui satisfait aux exigences prévues à l'article 26;

c) un manuel des mesures d'urgence qui satisfait aux exigences prévues à l'article 27;

d) un plan de dotation qui satisfait aux

of subsection 28(1);

(e) a training program that meets the requirements of subsection 28(3); and

(f) any other information or document required by a direction of the Chief Operations Officer.

(3) After receiving an application for an operation approval, the Chief Operations Officer may request the applicant to provide any additional information or documents relevant to the application.

(4) When a condition of an operation approval incorporates by reference any provisions of the application for the approval or of any other supporting document, those provisions are considered to be contained in the approval for the purposes of this Regulation.

Operations and maintenance manual

26 An operations and maintenance manual referred to in paragraph 25(2)(b) must provide comprehensive operating information and procedures to ensure safety, environmental protection and prevention of waste in the operation of the licensee's processing plant or LNG facility, including

(a) a list of all structures, facilities, equipment and systems critical to the operations, including

(i) drawings, plans, flow sheets and schematics,

(ii) measurements and technical specifications,

(iii) safety factors, operability limits and process control set points,

(iv) identification of all hazardous locations and their classifications, and

(v) locations of safety equipment and escape routes;

exigences prévues au paragraphe 28(1);

e) un programme de formation qui satisfait aux exigences prévues au paragraphe 28(3);

f) les autres renseignements ou documents exigés par une directive du délégué aux opérations.

(3) Après avoir reçu une demande d'approbation de l'exploitation, le délégué aux opérations peut demander à l'auteur de la demande de lui fournir des renseignements ou des documents supplémentaires qui sont pertinents pour la demande.

(4) Lorsqu'une condition d'une approbation d'exploitation incorpore par renvoi des dispositions de la demande d'approbation ou de documents à l'appui, ces dispositions sont réputées faire partie de l'approbation pour l'application du présent règlement.

Manuel d'exploitation et d'entretien

26 Le manuel d'exploitation et d'entretien visé à l'alinéa 25(2)b) doit contenir des renseignements complets sur le fonctionnement et les procédures pour assurer la sécurité, protéger l'environnement et prévenir le gaspillage dans le cadre de l'exploitation de l'usine de traitement ou de l'installation de GNL du titulaire de licence, notamment :

a) une liste du matériel, des structures, de l'équipement et des systèmes essentiels aux opérations, notamment :

(i) des dessins, des plans, des organigrammes et des schémas,

(ii) les mesures et les spécifications techniques,

(iii) les facteurs de sécurité, les seuils d'exploitabilité et les points de contrôle du processus,

(iv) l'identification de tous les emplacements dangereux et leur classification,

(v) l'emplacement de l'équipement de

(b) a summary of the systems and procedures for the inspection, testing and maintenance of all structures, facilities, equipment and systems critical to the operations; and

(c) the organizational structure for the plant or facility which

(i) clearly explains the authority and reporting relationship within the structure, and

(ii) provides the contact information and position of the person accountable for the manual and of the person responsible for implementing it.

Emergency procedures manual

27(1) A licensee's emergency procedures manual referred to in paragraph 25(2)(c) must contain procedures for how to respond to and mitigate the effects of any reasonably foreseeable event that might compromise safety or environmental protection at the licensee's processing plant or LNG facility.

(2) An emergency procedures manual must provide for

(a) contingency plans;

(b) a method of classifying incidents and response actions for specific incidents;

(c) internal and external notification, communication and reporting procedures;

(d) procedures for accessing essential safety and environmental information;

(e) organizational structure and resources to manage the emergency, including trained personnel, equipment and facilities;

sécurité et des voies d'évacuation;

b) un résumé des systèmes et des procédures pour l'inspection et l'entretien du matériel, des structures, de l'équipement et des systèmes essentiels aux opérations, ainsi que des essais sur ceux-ci;

c) la structure organisationnelle pour l'usine ou l'installation qui :

(i) d'une part, explique clairement la distribution des pouvoirs et les mécanismes de reddition de compte au sein de la structure,

(ii) d'autre part, indique le titre du poste et les coordonnées de la personne qui répond du manuel et de la personne chargée de sa mise en œuvre.

Manuel des mesures d'urgence

27(1) Le manuel des mesures d'urgence visé à l'alinéa 25(2)c) doit contenir des procédures de réponse et d'atténuation des conséquences relativement à tout évènement normalement prévisible qui pourrait compromettre la sécurité ou la protection de l'environnement à l'usine de traitement ou l'installation de GNL du titulaire de licence.

(2) Un manuel des procédures d'urgence doit contenir :

a) des plans d'urgence;

b) une méthode de classification des incidents et les mesures d'intervention pour des incidents particuliers;

c) les procédures d'avis internes et externes, de communication et de reddition de compte;

d) les procédures d'accès aux informations cruciales en matière de sécurité et de protection de l'environnement;

e) la structure organisationnelle et les ressources pour gérer l'urgence, notamment les membres du personnel formés, l'équipement, et les

installations;

(f) duties, responsibilities and authorities of all personnel involved in the emergency response, including job descriptions and checklists;

f) les fonctions, les responsabilités et les pouvoirs de tous les membres du personnel impliqués dans l'intervention en cas d'urgence, y compris les descriptions de postes et les listes de contrôle;

(g) communication protocols and coordination and liaison measures with relevant governmental emergency response organizations;

g) les protocoles de communication et les mesures de coordination et de prise de contact avec les organismes gouvernementaux pertinents d'intervention en cas d'urgence;

(h) a process for periodic review and updates of emergency response plans and personnel evacuation plans;

h) des processus d'examens et de mises à jour périodiques des plans d'intervention d'urgence et des plans d'évacuation du personnel;

(i) a description of the safety equipment and medical equipment;

i) une description de l'équipement de sécurité et de l'équipement médical;

(j) communication systems designed and protected to enable operation in an emergency; and

j) des systèmes de communication conçus et protégés pour permettre leur utilisation en cas d'urgence;

(k) all reasonably practicable steps to ensure safety and environmental protection.

k) toutes les mesures qu'il est raisonnablement possible de prendre pour assurer la sécurité et la protection de l'environnement.

(3) The licensee of a plant or facility must

(3) Le titulaire de la licence d'exploitation d'une usine ou d'une installation doit :

(a) establish and maintain a liaison with the agencies that may be involved in an emergency response activity at its plant or facility and consult with them in developing and updating its emergency procedures manual;

a) entrer et demeurer en contact avec les organismes qui peuvent être impliqués dans une intervention en cas d'urgence dans son usine ou son installation et les consulter lorsqu'il élabore et met à jour son manuel des mesures d'urgence;

(b) take all reasonable steps to inform persons who may be associated with an emergency response activity at its plant or facility of the practices and procedures to be followed and make available to them the relevant information from the emergency procedures manual; and

b) prendre toutes les mesures raisonnables pour informer les personnes susceptibles d'être associées à une intervention en cas d'urgence dans son usine ou son installation des méthodes et pratiques à suivre et mettre à leur disposition les parties pertinentes du manuel des mesures d'urgence;

(c) develop and implement a continuing educational program for the police, fire departments, medical facilities, other appropriate organizations and agencies and the public residing in proximity to the plant or facility to inform them of its location, potential

c) élaborer et mettre en application un programme d'éducation permanente à l'intention des services de police et d'incendie, des installations de santé, des autres organismes compétents et à l'intention du public qui habite à proximité de l'usine ou de l'installation, afin

emergency situations involving the plant or facility and the safety procedures to be followed in the event of an emergency.

de les informer de l'emplacement de celle-ci, des situations d'urgence pouvant la mettre en cause et des mesures de sécurité à prendre en cas d'urgence.

Staffing plan and training program

28(1) A licensee's staffing plan referred to in paragraph 25(2)(d) must provide for

(a) the number of persons necessary to operate its processing plant or LNG facility safely; and

(b) the competencies required for each position.

(2) The licensee must ensure that

(a) its plant or facility is at all times staffed with the full complement of personnel in accordance with the plan referred to in subsection (1);

(b) all personnel have, before assuming their duties, the necessary experience, training and qualifications and are able to conduct their duties safely, competently and in compliance with this Regulation; and

(c) records of the experience, training and qualifications of all personnel are kept and made available to the Chief Operations Officer on request.

(3) A licensee's training program referred to in paragraph 25(2)(e) must contain instructions for all personnel directly involved in the operation of its plant or facility respecting

(a) the safety practices and procedures applicable to the operation of the plant or facility;

(b) responsible environmental practices and procedures in the operation of the plant or facility;

(c) the proper operating procedures for the

Plan de dotation et programme de formation

28(1) Le plan de dotation du titulaire d'une licence visé à l'alinéa 25(2)d) doit contenir ce qui suit :

a) le nombre de personnes nécessaires pour exploiter l'usine de traitement ou l'installation de GNL de façon sécuritaire;

b) les compétences requises pour chaque poste.

(2) Le titulaire de licence doit veiller à ce que :

a) le personnel de l'usine ou de l'installation soit complet en tout temps en conformité avec le plan visé au paragraphe (1);

b) tous les membres du personnel disposent, avant d'exercer leur fonction, de l'expérience, de la formation et des compétences nécessaires pour s'acquitter de leurs responsabilités de façon sécuritaire, compétente et en respectant le présent règlement;

c) les dossiers sur l'expérience, la formation et les compétences de tous les membres du personnel soient conservés et mis à la disposition du délégué aux opérations sur demande.

(3) Le programme de formation d'un titulaire de licence visé à l'alinéa 25(2)e) doit contenir des instructions à l'intention de tous les membres du personnel directement impliqués dans l'exploitation de l'usine ou de l'installation sur les questions suivantes :

a) les pratiques et les méthodes en matière de sécurité applicables à l'exploitation de l'usine ou de l'installation;

b) les pratiques et les méthodes responsables de protection de l'environnement applicables à l'exploitation de l'usine ou de l'installation;

c) le mode de fonctionnement approprié de

equipment that they could reasonably be expected to use; and

(d) the emergency procedures set out in the manual referred to in section 27.

l'équipement qu'ils sont raisonnablement susceptibles d'utiliser;

d) les mesures d'urgence prévues dans le manuel visé à l'article 27.

Visitors

29 A licensee of a processing plant or LNG facility must take all reasonable steps to ensure that all visitors to its plant or facility

(a) are familiar with the components of the safety program necessary for their personal safety before they enter the site for the plant or facility; and

(b) comply with the safety program while they are on the site of the plant or facility.

Visiteurs

29 Le titulaire de la licence d'exploitation d'une usine de traitement ou d'une installation de GNL prend toutes les mesures raisonnables pour veiller à ce que les visiteurs de l'usine ou de l'installation :

a) connaissent les parties du programme de sécurité qui touchent à leur sécurité personnelle avant d'entrer dans l'usine ou l'installation;

b) respectent les exigences du programme de sécurité pendant qu'ils se trouvent sur le site de l'usine ou de l'installation.

Operations

30(1) The licensee of a processing plant or LNG facility must take all reasonable steps to ensure that

(a) operating activities at its plant or facility do not create a detriment to the environment or a hazard to the safety of persons that is greater than the detriment or hazard normally associated with identical activities carried on elsewhere;

(b) no equipment is operated with a hazard-detection alarm or shutdown device that is bypassed or rendered inoperable; and

(c) data recorded at the plant or facility are retained for analysis in the event of an incident or near-miss.

(2) The licensee of a plant or facility must

(a) test all hazard-detection devices as part of regular maintenance activities to determine

Exploitation

30(1) Le titulaire de la licence d'exploitation d'une usine de traitement ou d'une installation de GNL prend toutes les mesures raisonnables pour veiller à ce qui suit :

a) les activités d'exploitation à son usine ou à son installation ne causent pas de dommage à l'environnement ni ne constituent un danger pour la sécurité des personnes qui ne soit plus grand que les dommages ou le danger normalement associés à des activités identiques qui ont lieu ailleurs;

b) aucun appareil dont l'alarme de détection du danger ou le dispositif d'arrêt est dérivé ou rendu inutilisable n'est utilisé;

c) les données consignées à l'usine ou à l'installation sont conservées aux fins d'analyse en cas d'incident ou de quasi-incident.

(2) Le titulaire de la licence d'exploitation d'une usine ou d'une installation doit prendre les mesures suivantes :

a) effectuer des essais de tous les dispositifs de détection des dangers dans le cadre des travaux d'entretien courants, afin d'en tester le

whether they are fully functional;

(b) document and maintain records of all testing, repairs and replacement of parts in the hazard-detection devices;

(c) clearly mark the open and closed positions of main emergency shutdown valves;

(d) post signs along the site boundaries of its plant or facility indicating the name of the licensee and the telephone number to call in the event of an emergency at the plant or facility; and

(e) post signs warning of potential hazards.

Inspections

31(1) The licensee of a processing plant or LNG facility must

(a) conduct annually a complete inspection of its plant or facility to determine whether the plant or facility is in compliance with this Regulation, the conditions of the licence and the directions of the Chief Operations Officer; and

(b) submit to the Chief Operations Officer, within 30 days after the completion of the inspection, a report respecting the results of the inspection.

(2) An inspection under subsection (1) must be conducted

(a) during the calendar year following the year in which the operations approval was issued for the plant or facility but not more than 16 months after the date of the approval; and

(b) during each subsequent calendar year but not more than 16 months after the completion of the inspection in the previous calendar year.

(3) The Chief Operations Officer may

fonctionnement;

b) consigner et conserver des dossiers sur tous les essais, toutes les réparations et tous les remplacements de pièces sur les dispositifs de détection des dangers;

c) marquer clairement les positions de fermeture et d'ouverture des vannes d'arrêt d'urgence;

d) poser, sur le périmètre du site de l'usine ou de l'installation, des panneaux indiquant le nom du titulaire de licence et le numéro de téléphone à composer en cas d'urgence à l'usine ou l'installation;

e) poser des panneaux avertissant des dangers possibles.

Inspections

31(1) Le titulaire de la licence d'exploitation d'une usine de traitement ou d'une installation de GNL :

a) procède annuellement à une inspection complète de son usine ou installation pour déterminer si elle est en conformité avec le présent règlement, les conditions de la licence et les directives du délégué aux opérations;

b) remet au délégué aux opérations, dans les 30 jours suivant la fin de l'inspection, un rapport sur les résultats de l'inspection.

(2) Il doit être procédé à l'inspection visée au paragraphe (1) :

a) au cours de l'année civile suivant l'année pendant laquelle l'approbation d'exploitation de l'usine ou de l'installation a été accordée, mais au plus tard 16 mois après la date de l'approbation;

b) au cours de chaque année civile, mais au plus tard 16 mois après la fin de l'inspection effectuée l'année civile précédente.

(3) Le délégué aux opérations peut :

(a) by a notice direct the licensee of a plant or facility to test, inspect or perform an engineering assessment of all or any part of its plant or facility in accordance with the directions in the notice, if the Chief Operations Officer considers that the notice is warranted by concerns related to safety or environmental protection; and

a) par avis, ordonner au titulaire de la licence d'exploitation d'une usine ou d'une installation de procéder, conformément aux directives dans l'avis, à des essais, une inspection ou une évaluation technique de la totalité ou d'une partie de son usine ou son installation, si le délégué aux opérations estime que l'avis est justifié pour des motifs liés à la sécurité ou la protection de l'environnement;

(b) request the licensee to submit a report respecting the test, inspection or assessment by the deadline in the notice containing the request.

b) demander au titulaire de licence de lui fournir un rapport sur les tests, l'inspection ou l'évaluation avant l'expiration du délai prévu dans l'avis contenant la demande.

(4) If the licensee engages a contractor to perform an inspection under subsection (1) or a test, inspection or engineering assessment referred to in subsection (3), the contractor must be independent of

(4) Lorsque le titulaire de licence engage un entrepreneur pour procéder à l'inspection en vertu du paragraphe (1) ou à des essais, une inspection ou une évaluation en vertu du paragraphe (3), l'entrepreneur ne doit avoir aucun lien avec les personnes suivantes :

(a) the contractor who constructed the plant or facility;

a) l'entrepreneur qui a construit l'usine ou l'installation;

(b) any person who participated in the fabrication of any of the components to be tested; and

b) une personne qui a participé à la fabrication d'une pièce d'équipement devant faire l'objet d'essais;

(c) a contractor or lessee referred to in paragraph 24(2)(b).

c) un entrepreneur ou un locataire visé à l'alinéa 24(2)b).

(5) If an annual inspection under subsection (1) or a test, inspection or engineering assessment referred to in subsection (3) is performed by the licensee, it must be performed under the direct supervision of an agent engaged by the licensee for the purpose who

(5) Lorsqu'une inspection annuelle en vertu du paragraphe (1) ou des essais, une inspection ou une évaluation technique visés au paragraphe (3) sont effectués par le titulaire de licence, est alors obligatoire la supervision directe d'un mandataire engagé à cette fin par le titulaire de licence qui, à la fois :

(a) has sufficient expertise, knowledge and training to perform it competently; and

a) dispose de l'expertise, des connaissances et de la formation pour assumer ce mandat de façon compétente;

(b) is independent of

(i) a contractor who constructed the plant or facility or any person who participated in the fabrication of any of the components of the plant or facility,

(ii) a contractor or lessee referred to in paragraph 24(2)(b), and

(iii) a contractor engaged to conduct the inspection, test or engineering assessment.

(6) The Chief Operations Officer, on receiving a report under this section,

(a) shall make the report available for public inspection during normal business hours at the offices of the Chief Operations Officer and post on the Department's Internet website a notice stating that the report is so available; and

(b) may publish or distribute copies of the report.

External audits

32(1) The Chief Operations Officer may, by a notice to the licensee of a processing plant or LNG facility, inform the licensee of an audit to be conducted under this section of

(a) records related to the plant or facility, including prescribed programs, to determine whether the licensee was, during the period covered by the audit, in compliance with the Act, this Regulation and the licence in relation to the plant or facility; and

(b) the competency of personnel in supervisory or operational positions at its plant or facility.

(2) An audit contemplated by a notice given under subsection (1)

(a) shall be conducted by the Chief Operations Officer or by a person authorized by the Chief Operations Officer who is independent of the

b) n'a aucun lien avec les personnes suivantes :

(i) l'entrepreneur qui a construit l'usine ou l'installation ou une personne ayant participé à la fabrication d'une composante de l'usine ou l'installation,

(ii) un entrepreneur ou un locataire visé à l'alinéa 24(2)b),

(iii) un entrepreneur engagé pour procéder à une inspection, des essais ou une évaluation technique.

(6) Sur réception d'un rapport présenté en vertu du présent article, le délégué aux opérations :

a) doit rendre le rapport accessible au public pour consultation pendant les heures normales d'ouverture dans les bureaux du délégué aux opérations et publier un avis sur le site Internet du ministère précisant qu'il est ainsi possible de consulter le rapport;

b) peut publier ou distribuer des copies du rapport.

Vérifications externes

32(1) Le délégué aux opérations peut, en lui donnant avis, informer le titulaire de licence d'une usine de traitement ou d'une installation de GNL qu'il sera procédé à une vérification sous le régime du présent article :

a) des dossiers relatifs à l'usine ou l'installation, y compris des programmes réglementaires, pour déterminer si, pendant la période visée par la vérification, le titulaire de licence respectait la Loi, le présent règlement et la licence à l'égard de l'usine ou de l'installation;

b) de la compétence des membres du personnel occupant des postes fonctionnels ou de supervision à l'usine ou l'installation.

(2) La vérification visée par un avis donné en vertu du paragraphe (1) :

a) doit être effectuée par le délégué aux opérations ou par une personne qui n'a aucun lien avec le titulaire de licence et un

licensee and of any contractor engaged by the licensee to perform any services pertaining to an authorized activity related to the plant or facility; and

(b) shall be conducted during the period specified in the notice.

(3) The licensee to whom a notice is given pursuant to subsection (1) must

(a) make available to the auditor for inspection and copying any records required by the auditor;

(b) make every part of the plant or facility available for inspection by the auditor;

(c) make available for interviewing by the auditor any personnel having responsibility for preparing or monitoring any records related to the plant or facility or for operating the plant or facility; and

(d) ensure the co-operation of its employees and other personnel at the plant or facility with the conduct of the audit.

(4) The person conducting an audit under this section must prepare a report respecting the audit which must include all cases of non-compliance that have been noted.

(5) On completion of an audit report, the Chief Operations Officer

(a) shall provide a copy of the audit report to the licensee; and

(b) by a notice order the licensee to take any corrective action to remedy any case of non-compliance noted in the report.

(6) The Chief Operations Officer, on receiving an audit report under this section,

(a) shall make the report available for public inspection during normal business hours at the

entrepreneur engagé par le titulaire de licence pour fournir des services en lien avec une activité autorisée liée à l'usine ou l'installation;

b) doit être effectuée au cours de la période précisée dans l'avis.

(3) Le titulaire de licence à qui un avis est donné conformément au paragraphe (1) doit, à la fois :

a) mettre à la disposition du vérificateur pour examen et reproduction, les dossiers exigés par le vérificateur;

b) permettre l'accès au vérificateur à toutes les parties de l'usine ou de l'installation pour inspection;

c) mettre à la disposition du vérificateur pour des entrevues, les membres du personnel ayant des responsabilités liées à la préparation et à la surveillance des dossiers relatifs à l'usine ou l'installation ou à l'exploitation de l'usine ou l'installation;

d) veiller à la collaboration des employés et des autres membres du personnel de l'usine ou de l'installation dans le cadre de la vérification.

(4) La personne qui effectue une vérification sous le régime du présent article rédige un rapport sur la vérification qui doit faire état de tous les cas de non-conformité qui ont été relevés.

(5) Lorsque le rapport de vérification est terminé, le délégué aux opérations :

a) en fournit une copie au titulaire de licence;

b) donne un avis au titulaire de licence lui ordonnant de prendre les mesures correctives pour remédier aux cas de non-conformité identifiés dans le rapport.

(6) Sur réception d'un rapport de vérification présenté en vertu du présent article, le délégué aux opérations :

a) doit rendre le rapport accessible au public pour consultation pendant les heures normales

offices of the Chief Operations Officer and post on the Department's Internet website a notice stating that the report is so available; and

(b) may publish or distribute copies of the report.

PART 5

PHYSICAL AND OPERATIONAL CHANGES

Direction for operational changes

33 The Chief Operations Officer, on being satisfied that it is necessary or warranted in the circumstances, including circumstances related to safety, environmental protection or the occurrence of an incident or near-miss, may

(a) order the licensee of a processing plant or LNG facility to make an alteration to the plant or facility as specified in the direction; or

(b) order the licensee to make any change related to the operation of the plant or facility specified in the direction, for the period specified in the direction or until the occurrence of an event specified in the direction.

Alteration

34(1) A licensee of a processing plant or LNG facility must not alter the plant or facility to change its design or specifications unless a plan respecting the change is submitted to and approved by the Chief Operations Officer.

(2) Subsection (1) does not apply where the licensee is obligated to alter its plant or facility pursuant to any other law in force in Yukon but in that event the licensee must, as soon as practicable

d'ouverture dans les bureaux du délégué aux opérations et publier un avis sur le site Internet du ministère précisant qu'il est ainsi possible de consulter le rapport;

b) peut publier ou distribuer des copies du rapport.

PARTIE 5

MODIFICATIONS PHYSIQUES ET OPÉRATIONNELLES

Directive exigeant des modifications opérationnelles

33 Lorsqu'il est convaincu qu'il est nécessaire ou justifié de le faire dans les circonstances, notamment en lien avec la sécurité, la protection de l'environnement ou la survenance d'un incident ou d'un quasi-incident, le délégué aux opérations peut :

a) soit ordonner au titulaire de la licence d'exploitation d'une usine de traitement ou d'une installation de GNL d'apporter des correctifs à l'usine ou l'installation de la façon prévue dans la directive;

b) soit ordonner au titulaire de licence d'apporter toute modification liée à l'exploitation de l'usine ou de l'installation prévue dans la directive, pendant la durée de la période fixée dans la directive ou jusqu'à la survenance d'un évènement prévu dans la directive.

Modification

34(1) Le titulaire d'une licence d'exploitation d'une usine de traitement ou d'une installation de gaz naturel ne peut modifier l'usine ou l'installation d'une façon qui modifie sa conception ou ses spécifications que si un plan portant sur la modification a été soumis au délégué aux opérations et approuvé par celui-ci.

(2) Le paragraphe (1) ne s'applique pas lorsque le titulaire de licence est contraint de modifier son usine ou son installation pour se conformer à une autre loi en vigueur au Yukon, mais dans ces

but not less than seven days after the obligation arises, notify the Chief Operations Officer of the document evidencing the obligation.

Suspension

35 The Chief Operations Officer may issue directions respecting

(a) the circumstances under which a licensee of a processing plant or LNG facility must notify the Chief Operations Officer of the suspension of the operation of the plant or facility; and

(b) requirements as to when the notification of the suspension must be made.

Deactivation

36(1) A licensee of a processing plant or LNG facility may deactivate all or part of the plant or facility but must notify the Chief Operations Officer before the commencement of the deactivation operations.

(2) The Chief Operations Officer may, by a notice, order the licensee of a plant or facility to deactivate all or part of it if

(a) the Chief Operations Officer is satisfied the deactivation is necessary for the protection of the public, the environment or personnel engaged in the operation of the plant or facility;

(b) the operation of the plant or facility is suspended because of an order under section 9 of this Regulation or section 97 of the Act and the Chief Operations Officer is satisfied that there is no likelihood of the order being revoked within a reasonable time; or

(c) the plant or facility has not been in active service for at least 12 months.

(3) The deactivation of a plant or facility must

circonstances, le titulaire de licence doit, dès que possible, et au plus tard sept jours après la naissance de l'obligation, porter le document établissant l'obligation à la connaissance du délégué aux opérations.

Suspension

35 Le délégué aux opérations peut émettre des directives portant sur ce qui suit :

a) dans quelles circonstances le titulaire de la licence d'exploitation d'une usine de traitement ou d'une installation de GNL doit aviser le délégué aux opérations de la suspension de l'exploitation de l'usine ou de l'installation;

b) les exigences applicables au moment auquel l'avis de la suspension doit être donné.

Mise hors service

36(1) Le titulaire de la licence d'exploitation d'une usine de traitement ou d'une installation de GNL peut mettre la totalité ou une partie de l'usine ou l'installation hors service, mais il doit aviser le délégué aux opérations avant le début des opérations de mise hors service.

(2) Le délégué aux opérations peut, en donnant un avis, ordonner au titulaire de la licence d'exploitation d'une usine ou d'une installation d'en mettre la totalité ou une partie hors service dans l'une ou l'autre des situations suivantes :

a) le délégué aux opérations est convaincu que la mise hors service est nécessaire pour la protection du public, de l'environnement ou du personnel impliqué dans l'exploitation de l'usine ou l'installation;

b) l'exploitation de l'usine ou l'installation est suspendue en raison d'un ordre donné en vertu de l'article 9 du présent règlement ou de l'article 97 de la Loi et le délégué aux opérations est convaincu qu'il est peu vraisemblable que l'ordre soit révoqué dans un délai raisonnable;

c) l'usine ou l'installation n'a pas été en service depuis au moins 12 mois.

(3) La mise hors service d'une usine ou d'une

be carried out in accordance with

(a) this Regulation and any directions of the Chief Operations Officer; and

(b) if the deactivation is ordered pursuant to subsection (2), the provisions of the order.

(4) The licensee of a plant or facility must, within 30 days after the date of completion of its deactivation, notify the Chief Operations Officer of the completion date.

Reactivation

37(1) A licensee must not, without the approval of the Chief Operations Officer, commence any work to reactivate all or part of its processing plant or LNG facility that

(a) has been deactivated; or

(b) has not been in active service for at least 12 months.

(2) If the Chief Operations Officer approves the reactivation of all or part of the plant or facility,

(a) the reactivation must be performed in accordance with this Regulation and any applicable directions of the Chief Operations Officer; and

(b) the licensee of the plant or facility must notify the Chief Operations Officer of

(i) the completion of work leading to the reactivation within seven days after the completion date, and

(ii) the commencement of the reactivation within seven days after the commencement date.

Abandonment

38(1) The Chief Operations Officer may, by a notice, order the licensee of a processing plant or

installation doit être effectuée en conformité avec :

a) le présent règlement et les directives du délégué aux opérations;

b) si la mise hors service est ordonnée en application du paragraphe (2), les dispositions de l'ordre.

(4) Dans les 30 jours suivant la fin de la mise hors service, le titulaire de la licence d'exploitation d'une usine ou d'une installation avise le délégué aux opérations de la date d'achèvement.

Remise en service

37(1) Le titulaire de licence ne peut, sans l'approbation du délégué aux opérations, commencer des travaux en vue de remettre la totalité ou une partie de son usine de traitement ou son installation de GNL en service dans l'un ou l'autre des cas suivants :

a) elle a été mise hors service;

b) elle n'a pas été en service depuis au moins 12 mois.

(2) Si le délégué aux opérations approuve la remise en service de la totalité ou d'une partie de l'usine ou de l'installation :

a) il doit être procédé à la remise en service en conformité avec le présent règlement et les directives applicables du délégué aux opérations;

b) le titulaire de la licence d'exploitation de l'usine ou de l'installation avise le délégué aux opérations de ce qui suit :

(i) la fin des travaux permettant le remise en service, dans les sept jours suivant la date d'achèvement,

(ii) la date de remise en service, dans les sept jours suivant la date de la remise en service.

Abandon

38(1) Le délégué aux opérations peut, par avis, ordonner au titulaire de la licence d'exploitation

LNG facility to abandon all or part of the plant or facility if

(a) the Chief Operations Officer is satisfied that the abandonment is necessary for the protection of the public, the environment or personnel engaged in the construction or operation of the plant or facility;

(b) the construction or operation of the plant or facility has been suspended or terminated because of an order under section 9 of this Regulation or section 97 of the Act and the Chief Operations Officer is satisfied that there is no likelihood of the order being revoked within a reasonable time;

(c) the plant or facility or the part has been deactivated for at least 12 months and the Chief Operations Officer is satisfied that there is no likelihood of it being reactivated within a reasonable time; or

(d) the licensee has been ordered to deactivate the plant or facility or the part but has not complied with the order or has not conducted the deactivation in accordance with subsection 36(3).

(2) Whether the abandonment is initiated by the licensee or is ordered by the Chief Operations Officer, the licensee of a plant or facility must notify the Chief Operations Officer

(a) before the commencement of operations for the abandonment of all or any part of the plant or facility; and

(b) within 30 days after the abandonment operations have been completed.

(3) A licensee that abandons all or part of its plant or facility must do so in accordance with

(a) this Regulation and any applicable directions of the Chief Operations Officer;

(b) the licensee's current abandonment and reclamation plan; and

d'une usine ou d'une installation d'en abandonner la totalité ou une partie dans l'une ou l'autre des situations suivantes :

a) le délégué aux opérations est convaincu que l'abandon est nécessaire pour la protection du public, de l'environnement ou du personnel impliqué dans la construction ou l'exploitation de l'usine ou de l'installation;

b) la construction ou l'exploitation de l'usine ou de l'installation a été suspendue ou il y a été mis fin suite à un ordre donné en vertu de l'article 9 du présent règlement ou de l'article 97 de la Loi et le délégué aux opérations est convaincu qu'il est peu vraisemblable que l'ordre soit révoqué dans un délai raisonnable;

c) l'usine ou l'installation, ou une partie de celle-ci, a été mise hors services depuis au moins 12 mois et le délégué aux opérations est convaincu qu'il est peu probable qu'elle soit remise en service dans un délai raisonnable;

d) il a été ordonné au titulaire de licence de mettre l'usine ou l'installation hors service, ou la partie de celle-ci, mais il n'a pas respecté l'ordre ou n'a pas procédé à la mise hors service en conformité avec le paragraphe 36(3).

(2) Que l'abandon ait été à l'initiative du titulaire de licence ou ordonné par le délégué aux opérations, le titulaire de licence doit aviser le délégué aux opérations :

a) avant le début des opérations d'abandon de la totalité ou d'une partie de l'usine ou de l'installation;

b) dans les 30 jours suivant la fin des opérations d'abandon.

(3) Le titulaire de licence qui abandonne la totalité ou une partie de l'usine ou de l'installation doit le faire en conformité avec ce qui suit :

a) le présent règlement et les directives applicables du délégué aux opérations;

b) le plan actuel d'abandon et de remise en état du titulaire de licence;

(c) if the abandonment is ordered pursuant to subsection (1), the provisions of the order.

(4) If the abandonment involves the whole of the plant or facility, the licensee must

(a) in accordance with any directions of the Chief Operations Officer,

(i) dismantle and remove the plant or facility from its site, and

(ii) reclaim the surface of the site to put it in the same condition, as far as practicable, as it was prior to the construction of the plant or facility; and

(b) notify the Chief Operations Officer of the removal and reclamation within 14 days after the completion date.

(5) On receiving a notification pursuant to paragraph (4)(b) and on being satisfied that the reclamation operations have been completed, the Chief Operations Officer may cancel the licence for the plant or facility.

PART 6

RECORDS AND REPORTING

Retention of records

39 The requirements in CSA-Z276 respecting records retention are in addition to the requirements in section 17 of the *Oil and Gas Licence Administration Regulations* and this Part as they relate to LNG facilities.

Throughput records

40(1) The licensee of a processing plant or LNG facility must keep daily records of the following

(a) particulars of the volumes and heat content of fluids delivered to the inlet of the plant or facility by the licensee and by each shipper,

c) si l'abandon est ordonné en vertu du paragraphe (1), les dispositions prévues dans l'ordre.

(4) Lorsque l'abandon touche la totalité de l'usine ou de l'installation, le titulaire de licence doit :

a) en conformité avec les directives du délégué aux opérations :

(i) démanteler et enlever l'usine ou l'installation de son site,

(ii) remettre la surface du site en état pour qu'il soit, dans la mesure du possible, dans le même état qu'il était avant la construction de l'usine ou de l'installation;

b) aviser le délégué aux opérations de l'enlèvement et de la remise en état dans les 14 jours suivant la date d'achèvement.

(5) Lorsqu'il reçoit l'avis visé à l'alinéa (4)b) et qu'il est convaincu que les opérations de remise en état sont terminées, le délégué aux opérations peut annuler la licence pour l'usine ou l'installation.

PARTIE 6

DOSSIERS ET RAPPORTS

Conservation des dossiers

39 Les exigences de la norme CSA-Z276 en matière de conservation des dossiers s'ajoutent à celles prévues à l'article 17 du *Règlement sur l'administration des licences de pétrole et de gaz* et à la présente partie dans la mesure où elles portent sur les installations de GNL.

Dossiers relatifs au débit

40(1) Le titulaire de la licence d'exploitation d'une usine de traitement ou d'une installation de GNL doit consigner quotidiennement des dossiers sur ce qui suit :

a) les détails sur les volumes et l'enthalpie des liquides acheminés au point d'entrée de l'usine ou de l'installation par le titulaire de licence et

including the respective sources from which they were delivered;

(b) in the case of a processing plant, the volumes and heat content of residue gas, natural gas liquids and other products obtained by processing and delivered from the outlet of the plant by the licensee or on behalf of each shipper, including the intended delivery destination of those volumes;

(c) in the case of an LNG facility, the volumes and heat content of fluids delivered from the outlet of the facility by the licensee or on behalf of each shipper, including the intended delivery destination of those volumes;

(d) the volumes of any fluid flared, vented or used

(i) in the operation of the plant or facility, or

(ii) as a result of an emergency condition; and

(e) any other information required by the directions of the Chief Operations Officer.

(2) The daily records for a calendar month required to be kept by subsection (1) must be kept for a period of one year following that month.

(3) A licensee must, in the manner and frequency required by the directions of the Chief Operations Officer, conduct a balance analysis measuring input quantities and product and emission quantities for its plant or facility.

Monthly throughput reports

41(1) The licensee of a processing plant must submit to the Chief Operations Officer in respect of each month a report containing information specified in the directions of the Chief Operations Officer, based on the daily records for that month that are required to be kept by section 40.

(2) A report referred to in subsection (1) for any

chaque expéditeur, notamment sur les sources respectives desquelles ils proviennent;

b) dans le cas d'une usine de traitement, les volumes et l'enthalpie du gaz résiduaire, les liquides de gaz naturel et les autres produits obtenus du traitement et libérés au point de sortie de l'usine par le titulaire de licence ou au nom de chaque expéditeur, notamment sur la destination prévue de livraison de ces volumes;

c) dans le cas d'une installation de GNL, les volumes et l'enthalpie des liquides libérés au point de sortie de l'usine par le titulaire de licence ou au nom de chaque expéditeur, notamment sur la destination prévue de livraison pour ces volumes;

d) les volumes des liquides brulés, ventilés vers l'extérieur ou utilisés :

(i) soit dans le cadre de l'exploitation de l'usine ou de l'installation,

(ii) soit suite à une situation d'urgence;

e) les autres renseignements exigés dans les directives du délégué aux opérations.

(2) Les dossiers quotidiens pour un mois qui doivent être conservés en vertu du paragraphe (1) doivent être conservés pour une période d'un an après la fin de ce mois.

(3) Un titulaire de licence doit, de la façon et aux intervalles prévus dans les directives du délégué aux opérations, dresser un bilan des quantités d'intrants et des produits, d'une part, et des quantités d'émission, d'autre part pour son usine ou son installation.

Rapport mensuel sur le débit

41(1) Le titulaire de la licence d'exploitation d'une usine de traitement doit soumettre au délégué aux opérations, à l'égard de chaque mois, un rapport contenant les renseignements prévus dans les directives du délégué aux opérations, qui repose sur les dossiers quotidiens pour ce mois qui doivent être conservés en vertu de l'article 40.

(2) Le rapport visé au paragraphe (1) pour un

month may be submitted by a representative of the licensee authorized for the purpose.

(3) A report under subsection (1) must be submitted to the Chief Operations Officer by the 25th day of the month following the month to which the report relates.

(4) The Chief Operations Officer may authorize a later deadline than the one in subsection (3) for the submission of reports in respect of any specified month or months.

Measurement standards

42(1) In this Part

"cubic metre", in relation to gas, means the volume of gas which, at standard temperature and under standard pressure, will fill a space of one cubic metre; « *mètre cube* »

"gas" means raw gas, marketable gas and ethane in gaseous form; « *gaz* »

"heat content" means

(a) in relation to a volume or quantity of gas, the total amount of energy contained in the gas, including the sensible heat and latent heat of condensation, based on the gas being free of water vapour, or

(b) in relation to a volume of gas liquids, the total amount of energy contained in the gas liquids, expressed as their gaseous equivalent free of water vapour, including the sensible heat and latent heat of condensation but excluding heat loss due to the heat of vaporization of the gas liquids; « *enthalpie* »

"standard pressure" means the absolute pressure of 101.325 kilopascals; « *pression normale* »

"standard temperature" means 15 degrees Celsius. « *température normale* »

mois peut être présenté par un représentant du titulaire de licence qui a reçu une autorisation à cette fin.

(3) Le rapport visé au paragraphe (1) doit être présenté au délégué aux opérations au plus tard le 25e jour du mois suivant le mois faisant l'objet du rapport.

(4) Le délégué aux opérations peut autoriser qu'une date d'échéance visée au paragraphe (3) soit reportée pour la présentation des rapports portant sur un ou des mois précis.

Normes de mesure

42(1) Les définitions qui suivent s'appliquent à la présente partie.

« enthalpie » Selon le cas :

a) lorsqu'il s'agit d'un volume ou d'une quantité de gaz libre de vapeur d'eau, la quantité totale d'énergie qu'il contient, y compris la chaleur sensible et la chaleur latente de la condensation;

b) lorsqu'il s'agit d'un volume de liquides extraits du gaz, la quantité totale d'énergie qu'ils contiennent, exprimée selon leurs équivalents gazeux libres de vapeur d'eau, y compris la chaleur sensible et la chaleur latente de la condensation, mais sans tenir compte de la perte de chaleur reliée à la chaleur de vaporisation des liquides extraits du gaz. *"heat content"*

« gaz » S'entend notamment du gaz brut et de l'éthane sous forme gazeuse. *"gas"*

« mètre cube » À l'égard d'un gaz, s'entend du volume de gaz qui, à une température normale et soumis à une pression normale, occupe l'espace d'un mètre cube. *"cubic metre"*

« pression normale » Une pression absolue de 101,325 kilopascals. *"standard pressure"*

« température normale » Une température de 15 degrés Celcius. *"standard temperature"*

(2) For the purposes of this Regulation,

(a) volumes of gas shall be expressed in thousands of cubic metres to the nearest tenth of a thousand cubic metres;

(b) the heating value of gas shall be expressed in megajoules per cubic metre to the nearest hundredth of a megajoule per cubic metre;

(c) quantities of gas shall be expressed as heat content in gigajoules to the nearest whole gigajoule;

(d) volumes of gas liquids shall be expressed in cubic metres to the nearest tenth of a cubic metre;

(e) quantities of gas liquids shall be expressed as heat content in gigajoules to the nearest whole gigajoule.

(3) For the purposes of this Regulation, volumes of gas shall be converted to their heat content in gigajoules by multiplying the volumes by the gross heating value of the gas.

(4) For the purposes of this Regulation, the gross heating value used to convert volumes of gas to their heat content in gigajoules shall be calculated in accordance with *Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis* (GPA Standard 2172) published by the Gas Processors Association.

(5) If it is necessary for any purpose under this Regulation to determine volumes or quantities of in-stream components of gas,

(a) the respective volumes of the in-stream components of the gas shall be determined from a compositional analysis of the gas;

(b) the respective volumes of the in-stream components of the gas shall be converted to their heat content in gigajoules by multiplying those volumes by the gross heating value of the respective in-stream components as shown in

(2) Pour l'application du présent règlement :

a) les volumes de gaz sont exprimés en milliers de mètres cubes, au dixième de milliers de mètres près;

b) le pouvoir calorifique est exprimé en mégajoule par mètre cube, au centième de mégajoule par mètre cube près;

c) les quantités de gaz sont représentées par l'enthalpie en gigajoules, au gigajoule entier près;

d) les volumes de liquides extraits du gaz s'expriment en mètres cubes, au dixième de mètre cube près;

e) les quantités de liquides extraits du gaz sont représentées par l'enthalpie en gigajoules, au gigajoule entier près.

(3) Pour l'application du présent règlement, un volume de gaz est converti à son enthalpie en gigajoules en multipliant le volume du gaz par la valeur de son pouvoir calorifique supérieur.

(4) Pour l'application du présent règlement, la valeur du pouvoir calorifique supérieur utilisée pour convertir un volume de gaz à la valeur de son enthalpie en gigajoules se calcule en conformité avec la norme GPA 2172, publiée par la *Gas Processors Association* et intitulée *Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis.*

(5) S'il s'avère nécessaire, pour l'application du présent règlement, de déterminer le volume ou la quantité des composantes incorporées du gaz, le calcul suivant est utilisé :

a) les volumes respectifs des composantes incorporés du gaz sont déterminés à l'aide d'une analyse des composantes de ce gaz;

b) les volumes respectifs des composantes incorporées du gaz sont convertis à la valeur de leur enthalpie en gigajoules en multipliant ces volumes par la valeur du pouvoir calorifique supérieur respectif de chaque composante

the *Table of Physical Constants for Hydrocarbons and Other Compounds of Interest to the Natural Gas Industry* (GPA Standard 2145) published by the Gas Processors Association; and

(c) the quantities of the in-stream components calculated under paragraph (b) shall be normalized so that the aggregate quantities of those in-stream components equal the aggregate quantities of the gas.

(6) For the purposes of this Regulation, volumes of gas liquids shall be converted to their heat content in gigajoules in accordance with a direction of the Chief Operations Officer and the *Table of Physical Constants for Hydrocarbons and Other Compounds of Interest to the Natural Gas Industry* (GPA Standard 2145) published by the Gas Processors Association.

(7) The conditions of measurement of volumes and heating value when not otherwise specified in this section shall be

(a) in accordance with the *Electricity and Gas Inspection Act* (Canada), as amended from time to time; and

(b) corrected for actual atmospheric pressure to the nearest two kilopascals.

(8) A reference in this section to a publication of the Gas Processors Association shall be read as a reference to

(a) that publication, as amended from time to time; or

(b) if a new edition or revision of that publication is published, the new edition or the revised publication, as amended from time to time.

(9) Volumes or quantities of gas or gas products shown in a document submitted to the Chief Operations Officer under this Regulation are subject to adjustment by the Chief Operations Officer to

incorporée, comme le démontre la norme GPA 2145, publiée par la *Gas Processors Association* et intitulée *Table of Physical Constants for Hydrocarbons and Other Compounds of Interest to the Natural Gas Industry*;

c) les quantités des composantes incorporées du gaz obtenues selon les calculs prévus à l'alinéa b) sont normalisées de sorte que l'agrégat des quantités de ces composantes incorporées du gaz est égal à l'agrégat des quantités du gaz.

(6) Pour l'application du présent règlement, les volumes de liquides extraits du gaz sont convertis à leur enthalpie en gigajoules, selon les directives du délégué aux opérations et la norme GPA 2145, publiée par la *Gas Processors Association* et intitulée *Table of Physical Constants for Hydrocarbons and Other Compounds of Interest to the Natural Gas Industry*.

(7) Sous réserve d'autres précisions au présent article, la mesure de volumes et de l'enthalpie est effectuée selon les conditions suivantes :

a) celles prévues dans la *Loi sur l'inspection de l'électricité et du gaz* (Canada), dans ses versions successives;

b) celles qui sont corrigées pour la pression atmosphérique réelle aux deux kilopascals près.

(8) La mention au présent article d'une publication de la *Gas Processors Association* vaut mention :

a) de cette publication, dans ses versions successives;

b) si une nouvelle édition ou une révision de cette publication est publiée, cette nouvelle édition ou la publication révisée, dans ses versions successives.

(9) Les volumes ou les quantités de gaz ou de dérivés de gaz figurant dans un document fourni au délégué aux opérations en application du présent règlement peuvent faire l'objet d'ajustements par le délégué aux opérations :

(a) correct errors in measurement or in the recording or furnishing of data; or

(b) reflect reconciliations of those volumes or quantities resulting from downstream measurements or recalculations.

(10) A decision of the Chief Operations Officer respecting an adjustment under subsection (9) is final.

Incidents and near-misses

43(1) In the event of an incident or near-miss in the course of an authorized activity related to its processing plant or LNG facility, the licensee of the plant or facility must

(a) immediately notify the Chief Operations Officer of the incident or near-miss;

(b) submit to the Chief Operations Officer a preliminary report regarding the incident or near-miss within seven days after the incident or near-miss occurred; and

(c) submit to the Chief Operations Officer a final report regarding the incident or near-miss within 45 days after the incident or near-miss occurred.

(2) After being initially notified of an incident or near-miss, the Chief Operations Officer may, having regard to the degree of seriousness of the incident or near-miss,

(a) waive the requirement to submit a preliminary report or final report or both; or

(b) extend the deadline to submit a preliminary report or final report or both.

(3) The Chief Operations Officer, on receiving a report under this section,

(a) shall make the report available for public inspection during normal business hours at the offices of the Chief Operations Officer and post

a) soit pour corriger des erreurs de mesure ou des erreurs dans la consignation ou la communication de données;

b) soit pour tenir compte de la conciliation de ces volumes et ces quantités résultant de mesures prises en aval ou de nouveaux calculs.

(10) La décision du délégué aux opérations relativement à un ajustement visé au paragraphe (9) est définitive.

Incidents et quasi-incidents

43(1) En cas d'incident ou de quasi-incident dans le cadre d'une activité autorisée liée à son usine de traitement ou son installation de GNL, le titulaire de la licence doit :

a) aviser immédiatement le délégué aux opérations de la survenance de l'incident ou du quasi-incident;

b) soumettre au délégué aux opérations, un rapport préliminaire concernant l'incident ou le quasi-incident au plus tard sept jours après sa survenance;

c) soumettre au délégué aux opérations, un rapport définitif concernant l'incident ou le quasi-incident au plus tard 45 jours après sa survenance.

(2) Après avoir initialement été avisé de la survenance de l'incident ou du quasi-incident, le délégué aux opérations peut, selon la gravité de l'incident ou du quasi-incident :

a) soit suspendre l'exigence de soumettre un rapport préliminaire, un rapport définitif ou les deux;

b) soit prolonger le délai pour soumettre un rapport préliminaire, un rapport définitif ou les deux.

(3) Sur réception d'un rapport présenté en vertu du présent article, le délégué aux opérations :

a) doit rendre le rapport accessible au public pour consultation pendant les heures normales d'ouverture dans les bureaux du délégué aux

on the Department's Internet website a notice stating that the report is so available; and

(b) may publish or distribute copies of the report.

Press releases and press conferences

44 The licensee of a processing plant or LNG facility must notify the Chief Operations Officer at least 24 hours in advance of its intention to issue a press release or hold a press conference respecting an incident or near-miss occurring in the course of an authorized activity related to the plant or facility, except that in an emergency situation the notification must be made as much as possible in advance of the issuance of the press release or the holding of the press conference.

PART 7

PENALTIES

Penalties owing to Government

45 Penalties imposed pursuant to this Part are payable to the Government.

DIVISION 1

REPORTING-RELATED PENALTIES

Definitions for Division 1

46 In this Division,

"report" includes a notice, statement, record, plan of survey, drawing, log or other document; «*rapport*»

"reporting requirement" means

(a) a provision of this Regulation that requires a person to submit a report to the Chief Operations Officer,

(b) a provision of this Regulation that requires a person to notify the Chief Operations Officer of any specific

opérations et publier un avis sur le site Internet du ministère précisant qu'il est ainsi possible de consulter le rapport;

b) peut publier ou distribuer des copies du rapport.

Communiqués de presse et conférences de presse

44 Le titulaire de la licence d'exploitation d'une usine de traitement ou d'une installation de GNL doit donner un préavis d'au moins 24 heures au délégué aux opérations de son intention de publier un communiqué de presse ou de tenir une conférence de presse sur un incident ou un quasi-incident survenu dans le cadre d'une activité autorisée liée à l'usine ou l'installation. En cas d'urgence, le préavis peut toutefois être donné dès que possible avant la publication du communiqué de presse ou la tenue de la conférence de presse.

PARTIE 7

PEINES

Amendes payables au gouvernement

45 Les peines imposées sous le régime de la présente partie sont payables au gouvernement.

SECTION 1

PEINES LIÉES AUX RAPPORTS

Définitions applicables à la section 1

46 Les définitions qui suivent s'appliquent à la présente section.

« date d'échéance » S'entend :

a) à l'égard d'une exigence en matière de rapports qui prévoit la remise d'un rapport au cours d'une période, de l'expiration du dernier jour de cette période;

b) à l'égard d'une exigence en matière de rapports qui prévoit la remise d'un rapport avant l'expiration d'une date d'échéance, de cette date d'échéance;

c) à l'égard d'une exigence en matière de

information or of a past or future event within a specified period or by a specified deadline, or

(c) a request made by the Chief Operations Officer pursuant to this Regulation for the submission of a report to the Chief Operations Officer or to notify the Chief Operations Officer of any specific information or of a past or future event, if the notice containing the request specifies the period within which or the deadline by which the report must be submitted or the notification given; «*exigence en matière de rapports*»

"submission deadline" means

(a) in relation to a reporting requirement that provides for the submission of a report within a specified period, the expiration of the last day of the period,

(b) in relation to a reporting requirement that provides for the submission of a report by a specified deadline, the occurrence of that deadline,

(c) in relation to a reporting requirement described in paragraph (b) of the definition of "reporting requirement", the expiration of the period within which or the occurrence of the deadline by which the notification must be given, or

(d) in relation to a reporting requirement described in paragraph (c) of the definition of "reporting requirement", the expiration of the period or the occurrence of the deadline in the notice containing the request. «*date d'échéance d'un rapport*»

Report or notification on request

47 When a provision of this Regulation or a licence requires a licensee to submit a report to the Chief Operations Officer on request or to notify the Chief Operations Officer on request of any specified information or of any past or future event,

rapports décrite à l'alinéa b) de la définition d' « exigence en matière de rapports », de l'expiration de la période ou de la date d'échéance avant laquelle l'avis doit être donné;

d) à l'égard d'une exigence en matière de rapports décrite à l'alinéa c) de la définition d'« exigence en matière de rapports », de l'expiration de la période ou de la date d'échéance fixée dans l'avis contenant la demande. "*submission deadline*"

« exigence en matière de rapports » S'entend :

a) d'une disposition du présent règlement qui exige qu'une personne soumette un rapport au délégué aux opérations;

b) d'une disposition du présent règlement qui exige qu'une personne fournisse des renseignements particuliers au délégué aux opérations ou l'avise de la survenance d'un évènement passé ou à venir au cours d'une certaine période ou avant l'expiration d'un certain délai;

c) d'une demande du délégué aux opérations en application du présent règlement pour que lui soit soumis un rapport ou des renseignements particuliers ou pour qu'il soit avisé de la survenance d'un évènement passé ou à venir, si l'avis contenant la demande précise au cours de quelle période ou avant l'expiration de quelle échéance le rapport ou l'avis doit être fourni. "*reporting requirement*"

« rapport » S'entend notamment d'un avis, d'une déclaration, d'un dossier, d'un plan d'arpentage, d'un dessin, d'un registre ou d'un autre document. "*report*"

Rapport ou avis sur demande

47 Lorsqu'une disposition du présent règlement ou une licence prévoit que, sur demande, un titulaire de licence doit soumettre un rapport au délégué aux opérations ou lui fournir des renseignements ou l'aviser de la survenance d'un évènement passé ou à venir :

(a) the request must be contained in a notice given by the Chief Operations Officer to the licensee; and

(b) the notice must specify the period within which or the deadline by which the report must be submitted or the notification must be given.

Penalties for late submission or notification

48(1) If a person has a duty to comply with a reporting requirement but fails to do so by the submission deadline provided for in the relevant reporting requirement, the Chief Operations Officer may impose on that person a penalty not exceeding $50,000 and an additional penalty not exceeding $50,000 for each subsequent month during which the failure to comply continues.

(2) The Chief Operations Officer may impose on a person

(a) a penalty not exceeding $250,000, in the case of a failure by that person to comply with paragraph 43(1)(a) in respect of an incident or near-miss; or

(b) a penalty not exceeding $25,000 in the case of a failure by that person to notify the Chief Operating Officer of an intended press release or press conference in accordance with section 44.

Penalties related to non-compliant reporting

49(1) When a person submits a report pursuant to a reporting requirement, whether before or after the submission deadline for the report, the Chief Operations Officer may impose on that person

(a) a penalty not exceeding $500,000 in respect of the report if

(i) the report contains false or misleading statements,

(ii) the report contains information that is

a) la demande doit être contenue dans un avis donné par le délégué aux opérations au titulaire de licence;

b) l'avis doit préciser au cours de quelle période ou avant quelle date d'échéance le rapport doit être soumis ou l'avis doit être donné.

Peines pour les retards

48(1) Lorsqu'une personne doit respecter une exigence en matière de rapports et qu'elle omet de le faire avant la date d'échéance prévue dans l'exigence en matière de rapports applicable, le délégué aux opérations peut lui imposer une amende maximale de 50 000 $, ainsi qu'une amende maximale de 50 000 $ supplémentaire pour chaque mois subséquent pendant lequel l'omission se poursuit.

(2) Le délégué aux opérations peut imposer à une personne :

a) une amende maximale de 250 000 $ en cas de défaut par celle-ci de respecter l'alinéa 43(1)a) relativement à un incident ou un quasi-incident;

b) une amende maximale de 25 000 $ en cas de défaut par celle-ci d'aviser le délégué aux opérations de son intention de publier un communiqué de presse ou de tenir une conférence de presse en conformité avec l'article 44.

Peines découlant de la présentation non conforme de rapports

49(1) Lorsqu'une personne soumet un rapport en conformité avec une exigence en matière de rapports, que ce soit avant ou après la date d'échéance, le délégué aux opérations peut lui imposer :

a) soit une amende maximale de 500 000 $ relativement à ce rapport dans l'un ou l'autre des cas suivants :

(i) le rapport contient des déclarations fausses ou trompeuses,

(ii) le rapport contient des renseignements

inaccurate, or

(iii) the information required to be contained in the report is incomplete; or

(b) a penalty not exceeding $50,000 in respect of the report if

(i) the report is not in the format or medium provided for in the directions of the Chief Operations Officer,

(ii) the report is not completed in accordance with the directions of the Chief Operations Officer,

(iii) the report is not verified in the manner provided for in the directions of the Chief Operations Officer applicable to the report, or

(iv) the reporting requirement is based on a request of the Chief Operations Officer and the report is not completed in accordance with instructions contained in the request or is not verified in the manner provided for in the request.

(2) The Chief Operations Officer may impose on a person a penalty not exceeding $500,000 if that person, in notifying the Chief Operations Officer pursuant to this Regulation of any specific information or of a past or future event,

(a) makes a false or misleading statement;

(b) provides information that is inaccurate; or

(c) fails to provide any relevant information.

(3)The Chief Operations Officer may reduce or revoke a penalty imposed pursuant to this section on the basis of new evidence which, if it had been known to the Chief Operations Officer when the decision was made to impose the penalty, would have affected that decision.

inexacts,

(iii) les renseignements que doit contenir le rapport sont incomplets;

b) soit une amende maximale de 50 000 $ relativement à ce rapport dans l'un ou l'autre des cas suivants :

(i) le rapport n'est pas rédigé dans le format ou sur le support prévu dans les directives du délégué aux opérations,

(ii) le rapport n'est pas rédigé en conformité avec les directives du délégué aux opérations,

(iii) le rapport n'est pas vérifié de la façon prévue dans les directives du délégué aux opérations applicables au rapport,

(iv) l'exigence en matière de rapports découle d'une demande du délégué aux opérations et le rapport n'est pas rédigé en conformité avec les instructions contenues dans la demande ou n'est pas vérifié de la façon prévue dans la demande.

(2) Le délégué aux opérations peut imposer une amende maximale de 500 000 $ à une personne si, en communiquant des renseignements au délégué aux opérations ou en l'avisant de la survenance d'événements passés ou à venir en conformité avec le présent règlement, cette personne :

a) fait une déclaration fausse ou trompeuse;

b) fournit des renseignements inexacts;

c) omet de fournir des renseignements pertinents.

(3) Le délégué aux opérations peut réduire ou annuler une peine imposée conformément au présent article à la lumière de nouveaux éléments de preuve qui, s'ils avaient été portés à la connaissance du délégué aux opérations lorsque la décision d'imposer l'amende a été prise, auraient influé sur cette décision.

Penalty invoice

50 When a penalty is imposed on a person pursuant to this Division, the Chief Operations Officer shall send to that person an invoice for the penalty containing at least the following

(a) the reason for the penalty;

(b) the amount of the penalty;

(c) the due date by which payment of the penalty must be received by the Chief Operations Officer; and

(d) the text of section 113 of the Act.

DIVISION *2*

ADMINISTRATIVE PENALTIES

Definitions for Division 2

51 In this Division,

"administrative penalty" means a pecuniary penalty imposed pursuant to this Division; « *sanction administrative* »

"contravention" means a contravention of a provision of this Regulation enumerated in the Schedule or a condition of a licence, but does not include a contravention of a reporting requirement as defined in section 46. « *contravention* »

Penalties for Schedule contraventions

52 A contravention of a provision of this Regulation enumerated in the Schedule is subject to the imposition of a pecuniary penalty by the Chief Operations Officer in accordance with this Division and the Schedule.

Penalties for contraventions of licence conditions

53(1) If a licensee contravenes a condition of its licence, whether the condition is contained in the licence or is a condition of the licence by reason of this Regulation, the Chief Operations Officer may

Facture pour l'amende

50 Lorsqu'une amende est imposée à une personne sous le régime de la présente section, le délégué aux opérations lui envoie une facture pour l'amende contenant au moins ce qui suit :

a) les motifs de l'amende;

b) le montant de l'amende;

c) la date à laquelle le paiement de l'amende doit être reçu par le délégué aux opérations;

d) le libellé de l'article 113 de la Loi.

SECTION 2

SANCTIONS ADMINISTRATIVES

Définitions applicables à la section 2

51 Les définitions qui suivent s'appliquent à la présente section.

« contravention » Contravention à une disposition du présent règlement énumérée à l'annexe ou à une condition d'une licence. La présente définition ne vise pas les contraventions à une exigence en matière de rapports définies à l'article 46. *"contravention"*

« sanction administrative » Peine pécuniaire imposée en application du présent article. *"administrative penalty"*

Peines pour contraventions prévues à l'annexe

52 Quiconque contrevient à une disposition du présent règlement énumérée à l'annexe est passible d'une peine pécuniaire imposée par le délégué aux opérations en conformité avec la présente section et l'annexe.

Peines pour contraventions aux conditions d'une licence

53(1) Lorsque le titulaire d'une licence contrevient à une condition de sa licence, que la condition soit prévue sur la licence ou qu'elle soit imposée en application du présent règlement, le

impose on that licensee a pecuniary penalty in respect of that contravention in accordance with this Division.

(2) The maximum penalty that may be imposed by the Chief Operations Officer under subsection (1) in respect of a contravention of a licence condition is $500,000.

Procedures related to findings

54(1) If the Chief Operations Officer has reasonable grounds to believe that a contravention has occurred, the Chief Operations Officer may give to the person alleged to have committed the contravention a notice

(a) containing a description of the alleged contravention and of the evidence relied on as proof of the contravention;

(b) stating the maximum penalty that may be imposed for the alleged contravention if proven to the satisfaction of the Chief Operations Officer; and

(c) stating the rights of the person under subsection (2) and specifying a period of not less than 30 days within which the person may exercise a right under that subsection.

(2) A person to whom a notice is given under subsection (1) may, within the period specified in the notice,

(a) notify the Chief Operations Officer of the person's request for a hearing before the Chief Operations Officer at which the person may make representations and produce evidence related to the alleged contravention; or

(b) submit written representations and supporting evidence related to the alleged contravention to the Chief Operations Officer without a request for a hearing.

(3) Subject to subsection (4), the Chief Operations Officer may

(a) after conducting a hearing or considering representations and evidence submitted pursuant to paragraph (2)(b), make a finding

délégué aux opérations peut lui imposer une peine pécuniaire pour cette contravention en conformité avec la présente section.

(2) La peine maximale que peut imposer le délégué aux opérations en application du paragraphe (1) relativement à une contravention à une condition d'une licence est de 500 000 $.

Procédures découlant des conclusions

54(1) Lorsqu'il a des motifs raisonnables de croire qu'il y eu contravention, le délégué aux opérations peut donner à la personne à qui est attribuée la contravention alléguée, un avis qui :

a) contient une description de la contravention alléguée et des éléments de preuve à l'appui;

b) indique la peine maximale qui peut être imposée pour la contravention alléguée si la preuve de celle-ci est établie à la satisfaction du délégué aux opérations;

c) énonce les droits de la personne en vertu du paragraphe (2) et prévoit un délai minimal de 30 jours avant l'expiration duquel la personne peut exercer un droit en vertu de ce paragraphe.

(2) La personne qui reçoit un avis en vertu du paragraphe (1) peut, avant l'expiration du délai fixé dans l'avis :

a) soit aviser le délégué aux opérations du fait qu'elle demande la tenue d'une audience devant le délégué aux opérations pour présenter des observations et produire des éléments de preuve relativement à la contravention alléguée;

b) soit présenter au délégué aux opérations des observations écrites et les éléments de preuve à l'appui relativement à la contravention alléguée sans demander la tenue d'une audience.

(3) Sous réserve du paragraphe (4), le délégué aux opérations peut :

a) après avoir tenu une audience ou examiné les observations présentées en application de l'alinéa (2)b), déterminer soit s'il y eu ou non

that the person has or has not committed the contravention or that there is insufficient proof of the contravention; or

(b) after the period specified in the notice pursuant to paragraph (1)(c) has expired without any response received from the person to whom the notice was given, make a finding that the person has committed the contravention.

(4) The Chief Operations Officer may not make a finding that the person has committed a contravention pursuant to subsection (3) if the Chief Operations Officer is satisfied that

(a) the person exercised due diligence to prevent the contravention;

(b) the person reasonably believed in the existence of facts that if true would establish that the person did not commit the contravention; or

(c) the person's actions relevant to the contravention were the result of an officially induced error.

Imposition of administrative penalty

55(1) If the Chief Operations Officer makes a finding of a contravention by a person pursuant to section 54, the Chief Operations Officer may impose an administrative penalty on that person not exceeding the maximum penalty specified for that contravention provided for in section 52 or subsection 53(2), whichever applies.

(2) In determining the amount of an administrative penalty to be imposed on a person, the Chief Operations Officer shall consider the following

(a) previous administrative penalties imposed on that person;

(b) the gravity and magnitude of the contravention;

(c) the extent of the harm to others resulting from the contravention;

contravention par la personne, soit que la preuve de la contravention est insuffisante;

b) à l'expiration du délai fixé dans l'avis en application de l'alinéa (1)c), si aucune réponse n'a été reçue de la personne à qui l'avis a été donné, conclure qu'il y a eu contravention par la personne.

(4) Le délégué aux opérations ne peut conclure qu'il y a eu contravention par une personne en application du paragraphe (3) que s'il est convaincu :

a) soit que la personne a fait preuve de diligence raisonnable pour empêcher la contravention;

b) soit que la personne croyait pour des motifs raisonnables en l'existence de faits qui, si avérés, établiraient qu'il n'y a pas eu contravention par la personne;

c) soit que les gestes de la personne liés à la contravention résultaient d'une erreur imputable à l'autorité compétente.

Imposition d'une sanction administrative

55(1) Lorsqu'il conclut qu'il y a eu contravention par une personne en application de l'article 54, le délégué aux opérations peut lui imposer une sanction administrative dont le montant ne peut excéder la peine maximale pour cette contravention fixée à l'article 52 ou au paragraphe 53(2), selon le cas.

(2) Pour fixer le montant d'une sanction administrative à imposer à une personne, le délégué aux opérations tient compte des critères suivants :

a) les sanctions administratives antérieurement imposées à cette personne;

b) la gravité et l'ampleur de la contravention;

c) l'ampleur du préjudice subi par autrui suite à la contravention;

(d) whether the contravention was repeated or continuous;

(e) whether the contravention was deliberate;

(f) any economic benefit derived by the person from the contravention; and

(g) the person's efforts to prevent and correct the contravention.

Notice of administrative penalty

56 If the Chief Operations Officer imposes an administrative penalty on a person pursuant to section 55, the Chief Operations Officer shall give to the person a notice containing at least the following

(a) the Chief Operations Officer's finding respecting the contravention giving rise to the administrative penalty;

(b) the amount of the administrative penalty;

(c) a statement that the administrative penalty must be paid to the Government within 30 days after the notice is given to the person; and

(d) the text of section 113 of the Act.

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d) si la contravention s'est répétée ou si elle était continue;

e) si la contravention était délibérée;

f) les avantages économiques dont la personne a bénéficié en lien avec la contravention;

g) les efforts que la personne a déployés pour prévenir la contravention et y remédier.

Avis de sanction administrative

56 Lorsqu'il impose une sanction administrative à une personne en application de l'article 55, le délégué aux opérations lui donne un avis contenant au moins ce qui suit :

a) les conclusions du délégué aux opérations quant à la contravention ayant donné lieu à la sanction administrative;

b) le montant de la sanction administrative;

c) une déclaration établissant que la sanction administrative doit être payée au gouvernement dans les 30 jours suivant la date à laquelle l'avis est donné à la personne;

d) le libellé de l'article 113 de la Loi.

SCHEDULE

(Section 52)

CONTRAVENTIONS AND MAXIMUM ADMINISTRATIVE PENALTIES

NOTE: The text in brackets following the numbered provisions is intended to indicate the content of those provisions for the convenience of the reader and shall not be construed to limit the scope of the respective provisions.

$500,000 maximum

1 The maximum administrative penalty that may be imposed pursuant to this Regulation for a contravention of any of the following provisions is $500,000

- section 5 [Compliance with CSA-Z276];
- subsection 6(3) [Responsibility for compliance];
- section 8 [Prescribed programs];
- section 19 [Design and specifications];
- section 21 [Construction requirements];
- section 22 [Safety requirements];
- Subsection 36(3) [Deactivation];
- subsections 37(1) and (2) [Reactivation];
- subsection 38(3) [Abandonment].

$250,000 maximum

2 The maximum administrative penalty that may be imposed pursuant to this Regulation for a contravention of any of the following provisions is $250,000

- section 20 [Construction contract requirements];
- subsections 23(2) and (3) [Pressure testing];
- subsection 24(1) [No commencement of operation without approval];

ANNEXE

(article 52)

CONTRAVENTIONS ET AMENDES MAXIMALES

SANCTIONS ADMINISTRATIVES

NOTE : Le texte entre crochets suivant les dispositions n'est destiné qu'à indiquer quel est le contenu des dispositions à l'intention du lecteur et ne doit pas être interprété de façon à limiter la portée de ces dispositions.

Amende maximale de 500 000 $

1 La sanction administrative maximale qui peut être imposée en application du présent règlement pour une contravention à l'une ou l'autre des dispositions suivantes est de 500 000 $:

- l'article 5 [Respect de la norme CSA-Z276];
- le paragraphe 6(3) [Responsabilité liée au respect des exigences];
- l'article 8 [Programmes réglementaires];
- l'article 19 [Conception et construction];
- l'article 21 [Exigences en matière de construction];
- l'article 22 [Exigences en matière de sécurité];
- le paragraphe 36(3) [Mise hors service];
- les paragraphes 37(1) et (2) [Remise en service];
- le paragraphe 38(3) [Abandon].

Amende maximale de 250 000 $

2 La sanction administrative maximale qui peut être imposée en application du présent règlement pour une contravention à l'une ou l'autre des dispositions suivantes est de 250 000 $:

- l'article 20 [Exigences en matière de contrats de construction];
- les paragraphes 23(2) et (3) [Essais sous pression];
- le paragraphe 24(1) [Approbation préalable au début des opérations];

- subsection 24(2) [Unauthorized operator];
- section 29 [Visitors];
- section 30 [Operations];
- section 31 [Inspections];
- subsection 32(3) [Co-operation with audit];
- section 34 [Alteration].

$100,000 maximum

3 The maximum administrative penalty that may be imposed pursuant to this Regulation for a contravention of the following provision is $100,000

- section 40 [Throughput records].

- le paragraphe 24(2) [Exploitant non autorisé];
- l'article 29 [Visiteurs];
- l'article 30 [Exploitation];
- l'article 31 [inspections];
- le paragraphe 32(3) [Collaboration dans le cadre d'une vérification];
- l'article 34 [Modifications].

Amende maximale de 100 000 $

3 La sanction administrative maximale qui peut être imposée en application du présent règlement pour une contravention à la disposition suivante est de 100 000 $:

- l'article 40 [Dossiers relatifs au débit].

TOPIC: **Forecast new grid capacity requirement**

REFERENCE: **Application, pages 21 and 22 and Table 4-2; Appendix C - Table C-4, page C-8**

PREAMBLE:

Table C-4, for the Base Case no Alexco, shows the N-1 Surplus (shortfall) (MW) forecast for the years 2013 to 2020. Reference is made to those numbers in Table 4-2 and in the paragraph immediately below Table 4-2 on page 22.

Table C-4 and Table 4-2 show a 7.0 MW deficiency for 2015 and a 13.0MW deficiency for 2018 respectively, while the discussion in the paragraph following Table 4-2 speaks of that same capacity being required in late 2014 and 2017 respectively.

QUESTION:

a) Please clarify the timing of the need for new capacity in terms of when in the year cited new capacity is needed — i.e. the beginning or end of the year, based on the N-1 criteria.

b) Please provide a table similar to Table 4-2 that shows the need for new capacity in each of the years from 2015 to 2020 based on Table C-4.

c) Given that Table C-4 appears to show a need for additional new generating in 2017 (i.e. 10.9MW- 8.8MW = 2.1MW shortfall), why hasn't YEC chosen to apply for the commissioning of the third LNG unit during 2016, for the beginning of 2017?

ANSWER:

(a)

The timing of the need for new capacity is assumed to be the beginning of the year, reflecting that peak grid demand for non-industrial load (as used for the N-1 criteria) can occur in January.

(b)

Please see Table 1 below.

Table 1:
Forecast Base Case (No Alexco)
New Grid Capacity Requirement (2015-2020)

Year	2015	2016	2017	2018	2019	2020
Forecast Total Peak[1]	82.8 MW	84.3 MW	85.7 MW	87.2 MW	88.6 MW	90.2 MW
Forecast Industrial Peak[1]	5.3 MW	5.3 MW	5.3 MW	5.3 MW	5.3 MW	5.3 MW
Forecast Non-Industrial Peak[3]	76.5 MW	78.0 MW	79.4 MW	80.9 MW	82.3 MW	83.9 MW
Reliable Capacity Required[4]	113.5 MW	115.0 MW	116.4 MW	117.9 MW	119.3 MW	120.9 MW
Existing Peak Winter Capacity[5]	106.5 MW	106.5 MW	105.6 MW	104.8 MW	102.3 MW	100.2 MW
New Capacity Requirement[6]	7.0 MW	8.5 MW	10.9 MW	13.0 MW	17.0 MW	20.7 MW

Notes:

1. Forecast Total Peak is sum of industrial and non-industrial peak. Please see Table C-4 of Appendix C of Part 3 application, Base Case no Alexco.
2. Industrial peak reflects Base Case no Alexco.
3. Non-industrial peak load on grid, after assumed Demand Side Management (DSM), less 1 MW for assumed Haines Junction load. See Appendix C of Part 3 application.
4. Capacity planning requirements with N-1 reserve capacity (Forecast Non-Industrial Peak plus 37 MW for Aishihik hydro generation capacity [N-1 event is loss of transmission to the Aishihik hydro generation - also means loss of Haines Junction diesel capacity]).
5. Existing winter capacity in 2013 is 114.49 MW excluding Fish Lake hydro and Haines Junction diesel (see Table 2-3, Yukon Energy 20-Year Resource Plan: 2011-2030, December 2011). Reductions after 2013 reflect planned retirements of diesel engine units and the de-rated capacities of these units at this time (e.g., Mirrlees WD1 and WD2 have de-rated capacity of 8 MW versus rated capacity of 9.07 MW).
6. New capacity requirement equals forecast peak with N-1 reserve less existing peak winter capacity.

(c)

As YEC has noted in response to YUB-YEC-1-8 and YUB-YEC-1-25(b), based on current updated forecasts the currently projected in-service date for the third gas-fired unit is late 2016 in order to ensure that the capacity shortfall forecast for 2017 will be fully addressed.

As reviewed in response to YUB-YEC-1-25(b), the terms of reference provided require the YUB to submit a report and recommendations to the Minister on the Project as designated by OIC 2013/200 (which entails “the partial conversion of the generating

station from diesel fuel to natural gas fuel, with the replacement of two existing diesel generating units by three natural gas fired generating units").

Under the terms of reference the Board may comment on the necessity for the Project as well as its timing and design. While the Board does not have the jurisdiction to approve the Project, it may recommend to the government conditions for undertaking further stages of the Project (similar to its recommendations following the Carmacks-Stewart Transmission Project Part 3 hearing where the Board recommended that YEC not pursue Stage Two of the CSTP unless there is a firm commitment to connect a new mine load, and under the condition that ratepayers would not be adversely affected). In this context, the Application proposes clear conditions required for YEC to proceed with the third unit, i.e., the third 4.4 MW unit is to be installed as soon as is required to meet grid capacity planning requirements, and, in the context of OIC 2013/200 and the current hearing, this is what is required in the circumstances.

TOPIC: **Ratepayer impacts**

REFERENCE: **Application, Table 4-3, page 32; Appendix C, Table C-2, page C-5**

PREAMBLE:

QUESTION:

a) Please confirm that the numbers shown for Forecast Diesel (GW.h) (underneath each of the columns for 2015 to 2018) in Table 4-3, as part of the Annual Fuel Cost calculation are taken from Table C-2, page C-5, Appendix C.

ANSWER:

(a)

Confirmed. Forecast diesel numbers in Table 4-3 are from Table C-2 of Appendix C for Base Case no Alexco load forecast scenario.

TOPIC: **LNG capital cost sensitivity**

REFERENCE: **Application, page 36**

Table 4-6: Ratepayer Cost Savings Sensitivity to Project Capital

Costs and Fuel Cost Saving Risks Maximum Annual LNG Capital Cost Penalty at 13.1 MW ($million/yr)					
	0.474 Table 4-3	**0.626** plus 5%	**0.779** plus 10%	**0.932** plus 15%	**1.085** plus 20%
LNG Fuel Cost Saving ($/kW.h)					
0.13	3.6	4.8	6.0	7.2	8.3
0.11 Table 4-3	4.3	5.7	7.1	8.5	9.9
0.09	5.3	7.0	8.7	10.4	12.1
0.07	6.8	8.9	11.1	13.3	15.5
0.05	9.5	12.5	15.6	18.6	21.7

PREAMBLE:

The Board requires further information regarding cost savings sensitivity of the project.

QUESTION:

a) Please provide Table 4-6 in an Excel spreadsheet with all formulas intact and explanations about the contents of the cells and directions to users as regards to using the spreadsheet in determining cost savings sensitivities shown in the Table 4-6 and otherwise.

ANSWER:

(a)

Please see UCG-YEC-1-2 Attachment 1 for the excel version of Table 4-6 with all formulas intact.

Please note that Table 4-6 as copied in the above quote excludes the inset heading above all numbers in the original Table 4-6 at page 36 of the Application, which states: "Minimum LTA Displaced Diesel [GW.h/yr] to Break Even". In addition, Table 4-6 as

copied in the above quote also excludes three notes: (1) explaining the source for the "Maximum Annual LNG Capital Cost Penalty at 13.1 MW ($million/yr)"; (2) explaining the source for the "LNG Fuel Cost Saving"; and (3) noting that 17 GW.h LTA diesel displacement is forecast in 2015 with Base Case loads (no Alexco).

The table and Figure 4-1 show sensitivity of the Project to two sets of risks (capital and fuel costs) by providing the minimum long-term average ("LTA") annual diesel displacement required under each set of risks for fuel cost savings from the Project to offset the capital cost penalties from the Project in the first year of operation (annual capital cost penalties will gradually decline after the first year of operation due to depreciation impacts). The annual capital cost impacts are calculated in Table 4-4, which is also provided in UCG-YEC-1-2 Attachment 1 with all formulas intact.

Please also see response to YUB-YEC-1-53 for more details regarding the analysis in Table 4-6.

TOPIC: **Project components**

REFERENCE **Application, page 5, page 27 and page 31**

a. LNG truck off loading, storage, and vapourization facilities and related infrastructure...

Concurrent with the modernization and diesel unit replacement needs today at the Whitehorse Diesel Plant, there is an opportunity to convert from diesel to LNG-supplied gas-fired generation to meet growing electricity loads on the Yukon grid with a fuel that is cleaner burning and cheaper than diesel, benefitting both the environment and Yukon ratepayers.

In order to secure similar diesel displacement without requiring incremental new generation, Yukon Energy is also examining (for a future stage of the Project) retrofit of the remaining EMD units at Whitehorse to a blended use of gas and diesel during the few times when new gas-fired engines would not be fully able to displace all diesel generation.

PREAMBLE:

QUESTION:

a) What role do the vapourization facilities play in the operation of the LNG units? How do they function and what are their components?

b) What is the capacity of the proposed vapourization facilities and how does that capacity and its sizing relate to the needs of the first two LNG units, the third LNG unit and any possible future expansion of LNG use at this location (such as the conversion of existing EMD units as referred to at the top of page 31)?

c) Does the sizing of the vapourization facilities take into consideration and any other possible developments at the Whitehorse site (such as the possible future installation of dual fuel gas-diesel units such as the Wartsila diesel units cited as an alternative to the proposed LNG units)?

d) How does the sizing of the vapourization facilities affect the sizing of the piping systems to be installed in the utility trench?

e) What difference in cost would there be for the vapourization facility if sized to handle the three proposed LNG units only and the facility sized as currently proposed? What difference in cost would there be with respect to the sizing of the piping systems in the utility trench?

f) Are there any other facilities proposed as part of this project that are sized beyond the immediate needs of the project? If so, what are they and what is their additional cost as compared to sizing related to the project's immediate needs?

g) If there is a difference in vapourizer sizing and cost and in the piping systems from that needed for just the three proposed LNG units or for any other such additional costs, what justifies spending any extra capital on these facilities at this time?

ANSWER:

(a)

The vapourizer allows the conversion of the natural gas from its liquid form back to a gas. In its simplest form, the vaporizer can be described as a heat exchanger. The vaporizer system converts the very cold liquefied natural gas (-162 C) to a slightly warmer gas and then provides additional heat to warm the gas to above zero Celsius which is the minimum temp the engines are designed to use.

For the proposed facility, the heat will be provided by a hot water/glycol loop fed from a boiler or from “waste heat” generated by the new GE engines when one or both are running. The rate of vaporization can be adjusted to match the fuel required by the engines and boiler under various grid loading.

(b)

The vaporizer is sized to handle up to 30 MW of natural gas generation and heat load which would cover the 13 MW of LNG on-site generation and 17 MW of additional gas generation (single fuel) in the future in the Whitehorse Diesel Plant or 24 MW of 70/30

fuel blended natural gas/diesel engines. This is expected to accommodate the various future natural gas options available at this location.

(c)

As explained the YEC's response to YUB-YEC-1-33(b), the current design does accommodate the foreseeable natural gas generation options at the Whitehorse Diesel Plant in addition to 13 MW of generation in the Expanded Site Area.

(d)

The vaporizer was sized considering gas flow requirements to operate the new GE engines but also future conversion of the existing diesel units to bi-fuel or direct replacement with more efficient, cleaner burning natural gas engines. The Whitehorse Diesel Plant future flow requirements and as well as the natural gas flow rate needed to operate the converted oil boiler or new natural gas boiler were taken into consideration in the sizing of the buried gas piping to the Whitehorse Diesel Plan. The increase in the buried pipe sizing was from a three inch line to a 4 inch line.

(e)

The difference in the cost of the vaporizer sized for 13 MW versus 30 MW was $14k. The cost differential to go from a 3 inch gas line to a 4 inch gas line to the diesel plant is estimated to be $20k.

(f)

The items described in YEC's response to YUB-YEC-1-33(e) represent the only items sized for more than the 13 MW of on-site natural gas generation included in the current Project.

(g)

The spending of the $34k of extra capital costs on these initial facilities today to accommodate future ability to develop up to 30 MW of gas fired generation at the WTGS is prudent and cost effective planning that reflects the expected future retirement and modernization requirements within the next decade at this site, the potential for bi-fuel

uses in the interim period, the relatively minimal added costs needed today for this accommodation, and the comparatively greater costs that would be needed in the future to install a larger gas pipe to the diesel plant or to purchase and install on site a second or larger vapourizer.

Please also see response to YUB-YEC-1-6 (c through e).

TOPIC: **Fuel efficiency**

REFERENCE: **Application, page 11**

…the delivered cost of Shell Canada-supplied LNG at Whitehorse would be less than 15.5 cents/kWh (assuming 40% minimum average fuel conversion efficient).

PREAMBLE:

The Board requires further information.

QUESTION:

a) What are the manufacturer's minimum guaranteed unit heat rates for each of the GE J624 and Wartsila 6.7 MW units?

b) What unit efficiency does that translate to for each unit?

c) Why were unit efficiencies of 40% and 44% chosen for comparison purposes?

ANSWER:

(a)

Under maximum load, the minimum guaranteed (i.e., no tolerance) unit heat rates are as follows:

GE (4.375 MW): 8,167 kJ/kWh
Wartsila (6.7 MW): 8,765 kJ/kWh

(b)

The above unit heat rates yield the following guaranteed electrical efficiency:

GE (4.375 MW): 44%
Wartsila (6.7 MW): 41%

(c)

Yukon Energy believes an electrical efficiency of 40% represents a good minimum average efficiency rate for both new diesel and natural gas engines.

The original equipment manufacturer often report engine performance of up to 44-46% (including a 5% tolerance). In addition, these peak efficiencies can reflect optimum loads, fuel quality and environmental conditions. For the purposes of comparing diesel and natural gas fired engines and associated fuel consumption, a 40% efficiency was used as a conservative minimum average efficiency under a wide range of loads and environmental conditions. Sensitivity analysis with 44% efficiency was examined to consider potential higher efficiency, especially for the selected natural gas units, reflecting manufacturer's minimum guaranteed (i.e., no tolerance) unit heat rates.

TOPIC: **Project facilities**

REFERENCE: **Application, page 5**

PREAMBLE:

QUESTION:

a) How does YEC intend to deal with boil-off gas from its LNG installation?

b) What facilities does it intend to install to deal with the boil-off gas and what are the costs of those facilities?

c) Please provide the expected quantity of boil-off gas generated by the LNG installation on a month-by-month basis, both with the two-unit and three-unit developments.

d) Please provide details of the use of this gas on a month-by-month basis for both the two- and three-unit developments

e) Will any of this boil-off gas be replacing electricity as a source of energy? If so, please provide details.

ANSWER:

(a)

YEC intends to use all boil off gas internally for its own heating requirements and natural gas generation. All standby generators must be started once a month to ensure their availability. The detailed design of the LNG storage system allows the boil off gas to be used for heating and power generation.

(b)

Yukon Energy will be retrofitting a diesel fuel boiler in the Whitehorse diesel plant to burn natural gas. This boiler supplies building heat, engine block warming and heat for the

hydro power canal that provided water to Whitehorse Hydro Units 1/2/3. The cost of the 1,500 kW boiler retrofit is estimated to be $150,000.

(c)

The boil off gas rate will be less than 0.15% per day as guaranteed by the tank supplier. This will result with gas being generated within each storage tank at a rate of 0.0015* 166.5 m^3 of LNG or about 0.25 m^3 of LNG per day for each of the three larger tanks and 0.0015* 120 m^3 or about 0.18 m^3 of LNG per day for each of the two smaller tanks.

The maximum boil off rate for the two engine development will therefore be 3* 0.25 or about 0.75 m^3 per day of LNG. If the two smaller tanks are added (which is not in the current business case for the Project), the maximum boil off rate for the three engine development will be slightly higher at 0.75 +2*.18 or about 1.11 m^3 per day of LNG if the two additional tanks are purchased at that time. The decision as to whether purchase the additional storage at the time of the third engine will be based on the experience in the transportation of LNG at that time that may affect an economic decision as to whether the additional storage is necessary. Note that the boil off gas will be stored in the LNG tanks until the pressure in the tanks exceeds the pressure setting of the pressure relief valves on the tanks. The operating pressure differential range in the tanks is about 35 psi. The boil off gas will increase the pressure in the tanks by about 0.5 psi per day thus giving the tanks the ability to store the boil off gas for up to 35/0.5 or about 70 days before the boil off gas must be released from the tanks.

(d)

The existing heating load of the diesel plant boiler is estimated to be a minimum of 125 kW in the summer months and in excess of 400 kW in the winter months. The heating load of the LNG facility is estimated to be 100 kW in the winter when the engines are not running. The summer heating load in the LNG facility is estimated to be 25 kW. The natural gas engines will be run once per month for two hours at a minimum of 50% capacity.

The combined daily heating load in summer is 150 kW *24 or 3,600 kWh. To supply this energy in an 85% efficient boiler will require 4,248 kWh; in addition, 2-hour per month startup of the two natural gas engines will consume an additional 710 kWh per day, totaling 4,958 kWh. This will require 0.77 m^3 of LNG per day. This exceeds the forecast

boil off gas rate with 3 storage tanks. In the wintertime the heating load increases to 500 kW*24 or 12,000 kWh. Using an 85% efficient boiler will require 14,160 kWh of energy. In the winter months - monthly startups are assumed to not be required as the engines will be run to meet grid peak demand. This will require 2.18 m^3 of LNG per day, well above the forecast boil off gas rate with 3 storage tanks.

The three engine configuration will require a small additional heat load to cover the third engine in summer and winter and a 33% increase in engine startups in the summer months. The boil off rate will either be the same as the two engine scenario if no additional tanks are purchased or increase to 1.11 m^3 per day if the two additional tanks are purchased. Additional internal heating loads will also be assessed, such as heating the YEC office building and P125 Hydro building. Both are in close proximity to the Whitehorse diesel plant.

In both the two engine and three engine scenarios the LNG storage tanks will be capable of storing the boil off gas for up to 70 days before it would have to be used.

(e)

The use of the boil off gas is not expected to displace any significant amount of electricity as a source of energy.

TOPIC: **Project economics**

REFERENCE: **Application, page 27, footnote 40; Section 4.2.4, pages 30 and 31**

Percent displacement of other diesel estimates based on analysis provided in Appendix D. Actual displacement likely to be less than these estimates given the assumptions adopted in Appendix D to assess maximum potential displacement with full utilization of the new capacity.

PREAMBLE:

QUESTION:

a) What assumptions were made with respect to operation of existing diesel units in the YECSIM model and why were they made?

b) What operational reasons would there be to operate existing diesel units despite the installation of the proposed LNG generation?

c) For a case similar to the one adopted in the YECSIM model, by how much (in GWh) might existing diesel usage for operations reduce the amounts claimed for the proposed LNG generation in each of the years 2015 through to 2018?

d) Given those amounts of existing diesel use, what would be the reduction in fuel cost savings claimed for each of the years 2015 through to 2018 as shown in Table 4-3 on page 32?

e) Is it reasonable to accept the results of the YECSIM model as evidenced in Appendix D for purposes of YEC's economic analysis without some discounting of the benefits claimed? If the answer is yes, please explain why.

ANSWER:

(a)

There are no special assumptions regarding the operation of the diesel units in the YECSIM model. Currently, without any other renewable resources included in the model, the model assumes that the energy demand in excess of the energy available from hydro will be supplied through diesel or other thermal generation.

The comment in footnote 40 at page 27 of the Application addresses assumptions adopted in Appendix D rather than in the YECSIM model as such, i.e. Appendix D assumed maximum operation of the gas-fired units through each year in order to determine maximum ability to displace diesel generation during drought year conditions (taking into account the system's ability to store water). This assumption reflects the fact that it is cost effective to run gas units in summer or other times when diesel is not required if such operation facilitates equivalent added hydro storage that will displace diesel generation in winter or at other times when it is required.

In practice, maximum operation of the gas-fired units would not be planned automatically during each year, but would be planned based on when it was determined to be effective in adding to hydro storage (as well as when directly needed to displace diesel generation). The footnote 40 comment recognizes that the hydro storage maximization assumed in Appendix D would likely not be fully realized under all potential conditions. Experience will be needed over time to determine the extent to which gas-unit operation can be cost-effectively planned with regard to provision of added hydro storage such that optimum diesel displacement is achieved from gas-unit operation.

To elaborate on the above points, and as reviewed at pages 29 to 31 of the Application, Appendix D assessments assume maximum operation of the gas-fired units through the year in order to assess potential "old" diesel generation displacement with new gas-fired units, looking at the impact of one MW increments of gas-fired generation (within the relevant ranges) using the YECSIM model. This analysis helps to determine the minimum new gas engine capacity required to displace diesel during drought year conditions. Based on this analysis, Table 4-3 assumed that the 8.8 MW gas-fired generation will displace 100% of Base Case long-term average diesel requirements in 2015 and 95% of these requirements in 2016; and that 13.1 MW gas-fired generation

available in 2017 will displace 100% of Base Case long-term average diesel requirements in 2017 and 2018.

Similar analysis was used to support the assumed new diesel generation displacement of other diesel as shown for each year in Table 4-3 - and the fuel cost savings assessments provided in Table 4-3 reflect both the new diesel and new gas-fired unit forecast ability to displace other diesel generation on the grid. To be complete, it should therefore also be noted that the new diesel displacement of "old" diesel based on Appendix D analysis is also likely to be greater than would actually occur, and to the extent that this occurs the cost savings from use of gas-fired units may be greater than estimated, i.e., to the extent that "old" rather than "new" and more efficient diesel generation is being displaced by the gas units.

(b)

Operational reasons to operate existing diesel units on the grid despite the installation of the proposed gas-fired engines at WTGS include emergency conditions on the grid that cut off access to hydro generation (e.g., an N-1 event), severe drought conditions (when the gas-fired engines do not provide sufficient generation capability to meet thermal load requirements), local outages on the grid (when transmission access from Whitehorse units is cut off), and times when back-up is needed to the gas-fired engines (if they have any operational problems).

Further background is provided below.

Yukon's isolated grid has no access to external North American power grids to secure extra power when it is needed, or to sell surplus renewable generation when it occurs. This requires maintaining sufficient reliable capacity on the Yukon grid, and operation of thermal units as required when there is a shortfall in renewable generation relative to load at any time or location.

As noted in the Application, the Project will involve replacing two diesel generating units scheduled for retirement by 2015 with up to three new modular natural gas-fired generating units to maintain reliable capacity with lower operational cost generation. The remaining existing diesel units will continue to play an essential role in meeting the grid capacity planning requirements, minimizing the risk of service disruptions in very cold weather (through unplanned outages or other factors) or during an N-1 event.

The remaining existing diesel units will also supply energy during severe drought or low water conditions, peak winter periods or (in some instances) during planned system outages when the hydro and LNG generation is not sufficient to meet energy demand.

(c) and **(d)**

As noted in response to (a), the YECSIM model assumes that the energy demand in excess of the energy available from hydro will be supplied through thermal generation. The forecasts from this model reflect forecast weekly load and generation assessments based on available water year records without considering diesel requirements for N-1 events, local outages, planned maintenance events, peaking due to below-normal temperatures, etc. To the extent that diesel units are operated for such purposes not considered in the YECSIM model, there is no impact on diesel displacement savings opportunities related to new gas-fired units as forecast in the Application.

If the existing diesel units are otherwise used to supply energy forecast in the model when hydro is not available, the gas-fired generation would be reduced by the equivalent amount (GW.h) supplied through the existing diesel units. However, YEC has no basis to forecast or estimate at this time what, if any, such reduction may occur in any year.

To indicate how such matters would affect the cost savings, the following are noted (based on 2017 forecast loads and costs as assumed in the Application and without adjustments for updated diesel or other delivered LNG costs):

- In Table 4-3 of the Application the fuel cost for diesel is assumed at 28.7 cents/kW.h based on average diesel fuel cost as approved from YEC's 2012/13 GRA, while LNG fuel cost is assumed at 13.5 c/kWh (assumes supply from Shell Canada at Calgary at an AECO gas price of $4.50 per MMBtu and using A-Train units for delivery to Whitehorse).

- Based on these assumptions, the Application estimated the difference in fuel expense (LNG versus diesel) at about 15.2 cents/kW.h.

- In 2017, forecast LTA diesel generation is 26.9 GW.h, and it is assumed that this would be 100% displaced by new diesel (if 13.4 MW was to be installed) and 100% displaced by new gas units (if 13.1 MW was to be installed). Based on

these assumptions, fuel cost savings of $2.986 were estimated for 2017 with gas units versus new diesel units.

- If only 90% LTA displacement was assumed for both new diesel and gas units, the savings would be 90% of what is estimated (about $2.69 million).

- However, if the gas unit displacement is 95% [rather than 100% assumed in Table 4-3] and the new diesel displacement is 90% (reflecting perhaps much greater fuel savings certainty with gas, leading to more hydro storage occurring), then gas option fuel costs would be $3.84 million versus new diesel option fuel costs at $6.73 million, and overall fuel cost savings with gas would equal $2.89 million (about 97% of what shown in Table 4-3).

(e)

Yukon Energy was recently directed by the Yukon Utilities Board (YUB Order 2013-1, paragraph 60) for its 2012-2013 approved rate application to forecast hydro and diesel generation requirements assuming 100% long-term average hydro generation. The thermal generation estimates in Appendix D are based on 100% long-term average hydro and thermal generations. Yukon ratepayers are protected through the DCF if the actual thermal generation is lower than long-term average, in which case YEC will pay the difference to the DCF fund which will be used in future to help offset higher than long-term average thermal generation costs that occur (for example) in drought years.

Based on the above, the ratepayer impacts in Table 4-3 are calculated based on 100% long-term average hydro and thermal generations.

As reviewed above, YEC has no useful basis today to modify the assumed percentage displacement of forecast diesel by either new diesel or by gas-fired units. The risk assessments provided, however, allow for examination of the extent to which overall Project feasibility (in terms of yielding overall ratepayer savings during the Project's initial years of operation, let alone its full economic life) is sensitive to variations in diesel displacement levels.

TOPIC: **Modernization of the Whitehorse Thermal Generating Station**

REFERENCE: **Application, page 1**

The Project will modernize Yukon Energy's WTGS to meet growing requirements for reliable and flexible thermal generation on the Yukon grid, with conversion of WTGS thermal generation units scheduled for retirement from diesel fuel to cheaper burning and cleaner natural gas fuel supplied by liquefied natural gas ("LNG") delivered by truck from Alberta or British Columbia.

PREAMBLE:

QUESTION:

a) The Board notes YEC's submission that the proposed LNG project "will modernize Yukon Energy's Whitehorse Thermal Generation Station." Did YEC consider other locations for the project outside the Whitehorse area, wherein the related small substation could connect to the 35 kV distribution/transmission line?

b) Were any of the Whitehorse diesel engines recently refurbished? If so, please identify which units were refurbished.

c) Please provide a 10-year capitalization history (2003-2013), by unit, for each of the existing Whitehorse diesel units.

ANSWER:

(a)

Other locations were considered, but these were all within the broad Whitehorse area. As reviewed in response to YUB-YEC-1-10(c), Whitehorse was determined to be an optimum location for the Project and, in the Whitehorse area, the existing WTGS operation was determined to be the preferred location for the Project.

In reaching this decision, "greenfield" site options in the Whitehorse area and separate from the WTGS were examined such as the Takhini substation, but were not found to be

cost effective or practical (see response to YUB-YEC-1-10(c); also see response to YCS/LE-YEC-1-40 which copies a more detailed response provided to a YESAB information request in January 2014).

(b)

The only recent Whitehorse diesel refurbishment was WD3, a Mirrlees engine that was refurbished as described in YUB-YEC-1-13.

(c)

Please see Table 1 below. Please note capital repairs were completed to WD6 in 2011 at $271,497.50 – as this was a premature failure, these costs were charged to the Reserve for Injuries and Damages.

Table 1:
10-year capitalization history (2003-2013) for WTGS Diesel Units

Asset Description	Acquisition Da	WD1	WD2	WD3	WD4	WD5	WD6	WD7
WD4,5,6 Fuel Alarm Pump	01/08/2003				$ 2,622	$ 2,622	$ 2,622	
WD5 Engine Rebuild	01/08/2004					$ 182,783		
Control Improvements WD5	31/12/2005					$ 29,705		
Mirrlees & EMD Primary Cooling	15/11/2006	$ 5,119	$ 5,119	$ 5,119	$ 5,119	$ 5,119	$ 5,119	
P126 Cooling Sys Upgrade	15/11/2007	$ 39,925	$ 39,925	$ 39,925	$ 189,925	$ 189,925		
Time synchronizers WD3, 4,5	20/08/2009			$ 1,622	$ 1,622	$ 1,622		
WD3 Rebuild -Alternator rewind	31/12/2009			$ 85,653				
WD3 Rebuild - Engineering	31/12/2009			$ 14,335				
P126 WD3 Heat Exchanger Upgrade	30/11/2009			$ 111,079				
P126 WD3 Auxiliary System Replacement	29/11/2009			$ 153,290				
WD3 Rebuild -Parts	31/12/2009			$ 543,961				
WD3 Rebuild Labour	31/12/2009			$ 725,665				
WD7-Programable Logic Control	15/07/2009							$ 133,094
WD3 Rebuild - Add part costs	31/12/2010			$ 184,492				
WD3 Rebuild- Add labour costs	31/12/2010			$ 82,679				
P125 Generator Bearing Replacement	31/12/2010				$ 24,380	$ 24,380		
EMD Actuator UpgradeWD4,5,6	30/09/2011				$ 34,059	$ 34,059	$ 34,059	
WD5 Oil Cooler Replacement	31/12/2011					$ 8,287		
		$ 45,044	$ 45,044	$ 1,947,818	$ 257,727	$ 478,502	$ 41,800	$ 133,094

TOPIC: **Generating units**

REFERENCE: **Application, page 5**

Planned in-service for the first two natural gas-fired units (8.8 MW) is in fourth quarter 2014…

PREAMBLE:

QUESTION:

a) Please provide the forecast generation for the two new natural gas-generating units for the last quarter of 2014 and for 2015.

b) Please provide the forecast energy consumption for the natural gas-generating units for the years 2014 to 2020 inclusive. Clearly state your assumptions which support that forecast.

ANSWER:

(a)

The forecast actual generation expected to be required (taking into account current water conditions) for the two natural gas engines in the last quarter of 2014 is expected to be 0.6 GWh based on an in-service date in mid-December 2014. The forecast actual generation expected to be required (taking into account current water conditions) for these units in 2015 is 14.1 GWh without Alexco returning to service and 18.6 GWh if Alexco returns to service.

(b)

YEC is not able to provide useful forecasts of actual generation expected to be required (taking into account current water conditions) for the two natural gas engines in 2016, or for the three natural gas units in subsequent years. Short term generation forecasts used for operations planning are at best useful about 12 to 18 months into the future, given the inability to predict hydro generation capability beyond this time period (due to water

condition variability). Table 4-3 provides forecasts based on long-term average hydro generation and the Base Case load forecast without Alexco.

TOPIC: **Storage**

REFERENCE: **Application, page 5, footnote 5**

The revised Project plan retained the three gas-fired units for the Project (two to be developed in 2014), with provision for three initial LNG storage tanks (499.5 m3 for a total of 6 days storage) and the potential to add in future two additional smaller storage tanks (240 m3) to retain 6 days storage with the third gas-fired module.

PREAMBLE:

QUESTION:

a) Please provide the MW.h conversion of 499.5 m^3 of LNG.

b) Are the proposed natural gas units expected to be baseload or peaking units?

c) In terms of merit order, will the natural gas units be dispatched ahead of the Whitehorse diesel units? All other diesel units?

ANSWER:

(a)

A volume of LNG of 499.5 m^3 of LNG would provide approximately 1,287 MWh of electrical energy. This value assumes a 40% electrical efficiency for the engines as well as the higher heating value of the fuel of 1,015 BTU/ft^3.

(b)

The proposed natural gas units are expected to displace diesel generation that would otherwise be required, and are capable of operating under a range of operating load conditions.

Thermal generation (from natural gas or diesel) is required to provide reserve capacity for the isolated Yukon grid in order to meet emergency back-up requirements (e.g., N-1

event), as well as grid peak loads during winter months and other periods when water availability for hydro generation is limited by seasonal or drought conditions or is otherwise insufficient to meet grid load requirements. Thermal generation to meet this range of expected loads conditions must be capable of operating on an intermittent as well as on a sustained basis.

(c)

In normal operating conditions the natural gas engines will be dispatched ahead of all diesel generation due to their lower fuel costs. In certain grid outage power restoration scenarios some diesels may be started ahead of the natural gas units depending on the location and cause of the outage and restoration plan.

TOPIC: **Heat to start vapourizer**

REFERENCE: **Application, page 6, footnote 6**

Heat to start the vapourizer will be from the glycol/common water loop that will be kept warm year round (using multiple heat sources, e.g., diesel and gas units when operating, and an electric boiler, diesel and natural gas boiler in the diesel plant) to keep diesel and gas gensets on hot standby.

PREAMBLE:

QUESTION:

a) Please provide the forecast incremental costs of the heat required to start the vapourizer and to keep the diesel and gas gensets on hot standby for the years 2014-2020 inclusive.

ANSWER:

(a)

The diesel unit block heating loads in the Whitehorse diesel plant are not metered separate from the building heating system. In wintertime, the building and block heating system requires about 400 kW [YUB-YEC-1-35], two natural gas units will require 40 kW and the vapourizer will require 32 kW of heat along with 50 kW for the pressure building coils for the LNG tanks to maintain pressure to feed the vapourizer at low flow rates.

Total heat loads without running any gas engines are therefore estimated to be 522 kW in wintertime, of which 400 kWs (76.6%) already exist without the Project.

If no units are running to provide heat, over five winter months the heat load would approximate 1,905,300 kW.h [5*522*730 hours]. Assuming that gas is used to supply this heat at an updated average delivered LNG cost of $0.141/kW.h [YUB-YEC-1-13(a)] with a 85% efficient boiler (which increases energy required by 18%), the annual cost would approximate $317,004 (average winter month cost of $63,401), of which 76.6% reflects gas displacing oil that would be required for the diesel plant boiler even if the

Project did not proceed. As reviewed in YUB-YEC-1-35(d), about one third of this winter gas requirement would be supplied from winter boil off gas from the three tanks. In effect, the incremental gas available each month from boil off gas exceeds the incremental heat load due to the Project.

If units are running, the heat load that needs to be provided separately by gas would be reduced. The following reviews potential gas fuel heat requirements when gas units are run to supply the baseload default diesel requirements as set out in Table 4-3 of the Application:

- **2014**
  - The heat requirement related to the Project in 2014 would be insignificant as the LNG facility is not anticipated to be in-service until December 2014.

- **2015**
  - Assuming the 2015 generation of 17 GWh (long term average forecast generation under Base Case with no Alexco) would be in the heating months two engines averaging 8 MW would have to run 2125 hours per year to generate that much electrical power.
  - Assuming the 5 winter months would require the bulk of the generation, and heating when the engines are not running is when the heating load would be needed, in 2015 for about 3650 hours minus the 2125 hours the engines are running or 1525 hours.
  - The heat requirement to be supplied by gas fuel would be 1525* 522 or 796,050 kWh in 2015, i.e., fuel gas requirements are now only about 42% of the total winter heat requirement.
  - To generate 796,050 kWh of heat in an 85% efficient boiler would require 936,529 kWh of natural gas fuel. At updated delivered cost of $0.141/kWh of LNG this would have an annual cost of $132,051 in 2015 or $26,410 per month during winter.

- **2016 to 2020**
  - Assuming the same Base Case default diesel forecast, the heat requirements in the years 2016 up to 2020 would be less than 2015 as the natural gas engines would be running more hours to meet the renewable energy deficit.

TOPIC: **Decommissioning of units WD1 and WD2**

REFERENCE: **Application, page 7**

5. Decommissioning of two Mirrlees Diesel Units (WD1 and WD2) in the existing WTGS, including ancillary equipment and disconnection from the electrical grid.

PREAMBLE:

QUESTION:

a) Do the decommissioning costs include net salvage of the two WD units and any site reclamation costs? Please explain.

b) To December 31, 2013, what is the NBV of WD1 and WD2?

ANSWER:

(a)

The current estimate of decommissioning includes the costs to physically remove the engines from the plant, plus a provision to ship the units out of the territory. The budget does not include costs to refurbish the plant foundation or other system upgrades that would be required to re-deploy this space for other generation additions, and also do not include any salvage cost estimates (beyond the assumption that recoveries will offset transportation disposal costs) or site reclamation costs. Please see YUB-YEC-1-1(d) for the updated capital cost estimates and YUB-YEC-1-20 (a through c) for salvage issues.

(b)

The net book value for the WD1 and WD2 generating units at December 31 2013 is approximately $0.005 million. In addition, YEC accounts include costs for life extension and upgrades to the cooling system for these engines. The NBV of these assets is $0.085 million at December 31, 2013.

TOPIC: Economic Assumptions

REFERENCE: Application, page 11, and page 7, footnote 7.

This schedule is driven by forecast thermal generation requirements for the winter of 2014/15, both to provide new thermal generation capacity for reliable service during that winter and to save in excess of $2.1 million[7] of thermal fuel generation costs charged to ratepayers in 2015.

Estimated based on long-term average thermal generation of more than 14 GW.h for Base Case load forecast (no Alexco) over the six month period from January 1, 2015 to June 30, 2015; reflects the difference between estimated diesel fuel cost of $4.02 million with existing diesel units (based on Yukon Energy's 2012/13 GRA Compliance Filing average diesel fuel generation cost of 28.7 c/kW.h), and $1.89 million with new LNG units (based on LNG fuel cost at 13.5 c/kW.h with 100% diesel displacement, and assuming A-train LNG transportation is established and an AECO gas price of $4.5 per MMBtu).

PREAMBLE:

QUESTION:

a) Is the Alexco mine currently operating? If so, please redo the analysis showing the inclusion of the Alexco mine.

b) Does the base case load forecast include the Whitehorse Copper load in 2015? What is the effect if that load is included? Please show the analysis.

c) What is the current cost of diesel fuel?

d) What is the current cost of LNG fuel?

e) Does the fuel price comparison include the capital costs of the LNG project? If not, please show the analysis of the comparison, including the amortization of the capital costs.

ANSWER:

(a)

Alexco mining and milling operations are currently shut down. As noted in footnote 4 of Appendix C, in July 2013, Alexco Resource Corp announced that it would close Bellekeno mine for winter and will reopen in spring 2014 assuming the silver market has improved. Although the project could re-open in 2014, there is no current basis for addressing a 2014 forecast update – and the time of reopening the mine is very uncertain. Appendix C provides a load scenario assuming Alexco reopens in 2015 with loads similar to what had been forecast in the past.

(b)

As noted in Appendix C of the Application (footnote 1 on page C-1), the load forecast cases do not include WHCT.

With WHCT load at about 9.3 GW.h[1], the LNG fuel savings over the six month period from January 1, 2015 to June 30, 2015 would be about $2.7 million[2] or about $0.6 million higher fuel cost savings with WHCT load.

(c)

The current price for winter diesel fuel in Whitehorse as of February 1, 2014 is $1.1933/litre excluding GST. By way of comparison, this diesel fuel price in the last six months was as follows (six month average of $1.1265 per litre):

- Sept.-$1.1263
- Oct.-$1.0733
- Nov.-$1.1173
- Dec.-$1.1193
- Jan.-$1.1293
- Feb.-$1.1933.

[1] YEC's 2011-2030 Resource Plan Overview, Appendix A. Includes losses at 8.7%.

[2] Estimated based on Base Case load forecast (no Alexco) plus WHCT load; diesel fuel cost at 28.7 cents/kW.h and LNG fuel cost at 13.5 cents/kW.h.

(d)

YEC is not currently purchasing LNG. The delivered cost at YEC's Whitehorse plant for LNG in the Application has been estimated based on an assumed AECO index natural gas price of $4.50/MMBtu ($4.265/GJ) plus cost estimates for liquefaction at the to-be-developed Shell Canada Jumping Pound plant and LNG haul from Calgary to Whitehorse

Please see response to YUB-YEC-1-13(a) Table 1 which provides updated LNG costs delivered to YEC of 14.1c/kWh (updated from $13.5 cents/kWh). Footnote 1 of the response indicates LNG fuel costs are updated based on higher haul costs (per YUB-YEC-1-44), but retain the gas price of $4.5/MMBtu (which is stated to be retained as a conservative assumption based on AECO gas prices in the past six months of $3.7/MMBtu [$3.52/GJ] as outlined in response to YCS/LE-YEC-1-45(a)). The current AECO index gas price in February 2014 is $5.49/GJ, up from $3.84/GJ in January.

(e)

Please see Table 4-3 updated in response to YUB-YEC-1-13(a), which updates the Table 4-3 from the Application and provides a comparison of LNG and new diesel from 2014 to 2018 with updated capital cost estimates (including amortization of capital costs) and updated fuel cost estimates.

TOPIC: **Average annual utilization**

REFERENCE: **Application, page 7**

New natural gas-fired engines are assumed to have an economic life of 40 years, based on expected average annual utilization of these assets.

PREAMBLE:

QUESTION:

a) Please provide the assumed average annual utilization of each of the natural gas units in terms of operating hours/year and MW.h of generation/year for the years 2014-2020 inclusive.

ANSWER:

(a)

Please see response to YCS/LE-YEC-1-32 for the years 2015 through 2018 for average utilization of natural gas units assuming default diesel generation requirements with long term average hydro generation for Base Case scenarios without and with Alexco as well as for Scenario A load forecasts (2018), and for review as to why such analysis becomes less useful when it addresses higher load cases and was therefore not extended beyond 2018. No attempt has been made to assess the extent to which each of the gas units might have different operating hours within any year.

No material use of LNG plant is expected in 2014 as commissioning is not expected to occur until December 2014.

Beyond assessing average annual utilization assuming long-term average hydro generation, YEC is not able to provide useful forecasts of actual generation expected to be required (taking into account current water conditions) for the two natural gas engines in 2016, or in subsequent years. Short term generation forecasts used for operations planning are at best useful about 12 to 18 months into the future, given the inability to predict hydro generation capability beyond this time period (due to water condition

variability). Please see response to YUB-YEC-1-38(a) for a forecast of actual gas unit generation in 2015, taking into account current water conditions and the Base Case load without Alexco as well as the Base Case load with Alexco.

TOPIC: **Transportation costs**

REFERENCE: **Application, page 7**

Truck delivery of LNG to the WTGS will use a new double trailer (A-Train) combination with a 95,000 litre capacity, although currently available Tridem units with a 54,000 litre capacity may be used initially if there are delays in the licensing and/or fabrication of the new A-Train units.

PREAMBLE:

QUESTION:

a) Please provide the cost differential in $/litre comparing the A-Train costs versus the Tridem delivery costs.

ANSWER:

(a)

Table 1 provides updated LNG haul costs estimates by PROLOG Canada as at late December 2013 for LNG haul by A-Train or Tridem units to Whitehorse from Shell Jumping Pound (JP) at Calgary, Fort Nelson, and Fortis (Delta BC). Cost differences for A-Train versus Tridem units for each supply option are provided in Table 1 in $/MMBtu, $ per m^3, and $ per litre of LNG delivered to Whitehorse. Please see Attachment 1 to this response for the electronic version of Table 1.

Prior Cost Estimates

Prior LNG haul cost estimates were provided by PROLOG Canada in February 2013, as summarized in Table 1, assumed full annual operation for 360 days per year, as well as stable and large enough haul requirements to support such operation.

Previous YEC assessments, however, also noted potential underutilization of equipment for initial YEC requirements from Calgary. As a result, the regulatory filings to date (e.g., the YESAB project proposal and the recent Part 3 Application) increased these cost

estimates, e.g., the haul cost from Calgary was assumed at $5.16/MMBtu with A-Train units (18% increase over the earlier PROLOG cost estimate of $4.37/MMBtu) and $7.44/MMBtu with Tridem units (10% increase over the earlier PROLOG cost estimate of $6.76/MMBtu). Economic analysis for the Whitehorse Diesel-Gas Conversion Project has continued to demonstrate that the Project continues to yield material cost savings relative to diesel even when Tridem units are required to be used. A-Train units have been assumed to become licensed in time to allow adoption for the Project.

Updated Costs

Overall, higher costs per MMBtu for diesel powered units are indicated in Table 1 as compared with earlier estimates from February 2013 (all costs assume units fully utilized on an annual basis):

- A-Train cost estimate increased as follows for Calgary, Fort Nelson, and Delta BC LNG supplies to Whitehorse (assumed 95.3 m^3 LNG payload per unit):
  - Calgary (JP): increase from $4.37/MMBtu to $5.31/MMBtu;
  - Fort Nelson: increase from $1.90/MMBtu to $2.35/MMBtu; and
  - Delta BC (Fortis): increase from $5.26/MMBtu to $5.99/MMBtu.

- Tridem cost estimates increased as follows for Calgary and Fort Nelson, and decreased for Delta BC, for LNG supplies to Whitehorse (assumed LNG payload per unit has increased from 54 m^3 to 64.5 m^3, reflecting units now contracted by NT Energy through Ventures West and CVA):
  - Calgary (JP): increase from $6.76/MMBtu to $6.98/MMBtu;
  - Fort Nelson: increase from $2.88/MMBtu to $3.09/MMBtu; and
  - Delta BC (Fortis): decrease from $8.10/MMBtu to $7.85/MMBtu.

The updates for all sources and options reflect higher assumed fuel consumption per mile for the haul, higher hourly labour costs, increased unload time at Whitehorse, and reduction in assumed operating days per year[1]. Calgary haul cost increases per MMBtu also reflect the impact of 4.63% lower LNG energy content assumptions for this supply source (based on Shell Canada's contract specifications), while Delta BC updated haul costs reflect the impact of the higher LNG energy content assumptions based on Fortis new Rate Schedule 46[2].

When looking at potential underutilization of equipment during initial YEC Project years of operation, the updated A-Train costs are increased by 10% for initial low utilization and the updated Tridem costs are increased by 5% for initial low utilization.

[1] By way of example, for the Calgary supply with A-Train, the per trip cost increase of $1,518 (from $9,471 to $10,989) relates primarily (over 80%) to increased labour and other variable O&M costs (including related administration and profit mark-ups); the balance of the per trip cost increase reflects assuming a 325 versus 360 day operating year (reduces the number of trips per year over which fixed costs and related administration and profit mark-ups are allocated; the 325 operating days provides 40 days per year downtime for: maintenance on tractors and trailers; selected statutory holidays; and extreme weather – spread out over the year).

[2] In the case of the Fort Nelson A-Train hauls, it also appears that the Feb. 2013 estimates were too low based on assumptions at that time, and that the cost should have approximated $2.2/MMBtu (rather than $1.9/MMBtu).

Table 1: **LNG TRIP COSTS to Whitehorse from Shell, Ft. Nelson & Fortis** **Update** **31-Dec-13**
(Assumes full annual utilization of LNG haul equipment)

Current Update - LNG energy content per supply source as shown

Yukon "A Train" MMBtu/ Cu.M.	Source	Destination	Distance (kms)	Round Tr. (mi)	Payload (m3)	Trip Cost ($)	Trip Cost $ per mi.	Cost/m3	Cost/litre	MMBtu/ Truckload	Diesel Power Cost/ MMBtu
21.708	Shell JP	Whitehorse	2,367	2,942	95.3	10,989	3.74	$115.31	$0.115	2,069	$5.31
22.761	Ft. Nelson	Whitehorse	998	1240	95.3	5,106	4.12	$53.58	$0.054	2,169	$2.35
23.118	Fortis Delta	Whitehorse	2721	3380	95.3	13,192	3.90	$138.43	$0.138	2,203	$5.99
Tridem 21.708	Shell JP	Whitehorse	2,367	2,942	64.5	9,773	3.32	$151.52	$0.152	1,400	$6.98
22.761	Ft. Nelson	Whitehorse	998	1240	64.5	4,539	3.66	$70.37	$0.070	1,468	$3.09
23.118	Fortis Delta	Whitehorse	2721	3380	64.5	11,704	3.46	$181.46	$0.181	1,491	$7.85

Major Changes: in addition to adjustments for LNG energy content assumptions by source: longer distances; Tridem payload increase; 325 day vs 360 day operating year; 4.5 mi/USG vs 5 mi/USG; driver @ $30/hr vs $23.2/hr; 3 vs 2 hrs load/unload; +1 hour travel Calgary and -1 hr travel Ft Nelson

Previous Update - Feb 12, 2013 - Assumes 22.761 MMBtu/Cu. M [Fortis estimates derived - not provided in Feb 12/13 update]

Yukon "A Train"	Source	Destination	Distance (kms)	Round Tr. (mi)	Payload (m3)	Trip Cost ($)	Trip Cost $ per mi.	Cost/m3	Cost/litre	MMBtu/ Truckload	Diesel Power Cost/ MMBtu
	Shell JP	Whitehorse	2,327	2,892	95.3	9,471	3.27	$99.38	$0.099	2,169	$4.37
	Ft. Nelson	Whitehorse	978	1215	95.3	4,127	3.40	$43.31	$0.043	2,169	$1.90
	Fortis Delta	Whitehorse	2721	3382	95.3	11,413	3.37	$119.75	$0.120	2,169	$5.26
Standard Tridem	Shell JP	Whitehorse	2,327	2,892	54	8,307	2.87	$153.83	$0.154	1,229	$6.76
	Ft. Nelson	Whitehorse	978	1215	54	3,540	2.91	$65.56	$0.066	1,229	$2.88
	Fortis Delta	Whitehorse	2721	3382	54	9,960	2.95	$184.45	$0.184	1,229	$8.10

Source: PROLOG Canada

TOPIC: **Project costs**

REFERENCE: **Application, page 8**

Table 3-1 provides a summary of the estimated Yukon Energy capital costs of $34.4 million (approximately $3.9 million per MW) for the initial Project facilities at the WTGS to be completed prior to the end of 2014, including the first two gas-fired units and other work related to LNG facilities (truck offloading, storage, and vapourization), distribution and communication line, utility trench, and decommissioning of the two Mirrlees diesel units. These costs are preliminary estimates developed in mid-2013 based on preliminary quotes and preliminary engineering. (Underlining added)

PREAMBLE:

QUESTION:

a) Please provide the expected range of costs from preliminary to actual using confidence intervals.

b) What is the decision point in terms of capital costs where the project should not proceed?

c) What is the decision point in terms of rising prices for liquid natural gas or declining cost of diesel fuel where the project should not proceed?

d) Is there a further update to the preliminary costs?

e) Is the owner of YEC willing to accept as a cost to the shareholder any cost overruns from the preliminary engineering estimates?

f) Please provide the detailed NPV model in Excel format that compares the LNG installation (3 generators) to a complete new diesel replacement. Please include all assumptions and explain the results.

g) What is the impact of this project on the proposed DCF and ERA modifications as requested by YEC?

h) Prepare a sensitivity analysis that show the point of comparability in the DCF based on stable diesel prices but increasing LNG prices on an NPV basis.

ANSWER:

(a)

Estimated capital costs for initial Project facilities at WTGS included in Table 3-1 of the Application were preliminary estimates developed in mid-2013 based on preliminary quotes and preliminary engineering. The response to YUB-YEC-1-1(d) provides capital cost updates as of late January 2014 based on the following:

- The current regulatory review process,
- Final site configuration (i.e., no lease of the White Pass lands),
- Contractual costs for selected key long lead equipment (two GE engines [Gas Drive], three LNG storage tanks [499.5 m^3 total capacity], skid mounted vaporization and related equipment, and transformer), updated site layout design, and contractual costs for Project Management and Project Engineering.
- Contingencies of $1.45 million are included in the update, with $1 million for construction contracts (primarily for the untendered civil, mechanical and electrical contracts estimates at $6.8 million as part of Site Development costs) and the balance for Engineering, Project Management and Owners.

The January 2014 capital cost update includes a number of contractual costs for key items (such as engines, storage and vapourization, engineering and project management), with the only untendered items being civil, mechanical and electrical contracts ($1 million of contingency is included for contracts not awarded). YEC is currently not anticipating any additional costs for mitigation measures that may result from the YESAB review currently underway.

Actual costs may be impacted by a number of factors, including costs related to delay (which as noted in YUB-YEC-1-2(a) and (b) may range considerably).

(b) and **(c)**

Project economics, risks and impacts on ratepayer savings are reviewed in the Application (Section 4.2.4 and Section 4.3). Table 4-4 reviews the capacity cost sensitivity of the Project (13.1 MW LNG vs New Diesel) with 5% to 20% potential capital cost penalties and Table 4-5 reviews the range of fuel cost savings available under varying conditions. Table 4-6 reviews ratepayer cost saving sensitivity to Project capital costs and fuel cost savings risks. The analysis in Table 4-6 highlights the extent to which the Project's economics and ratepayer cost savings are very robust.

This assessment also highlights the extent to which any decision not to proceed with the Project would be based on a number of factors (not just capital cost or fuel costs savings), i.e., the assessment looks at capital cost, fuel cost savings and displacement of diesel generation.

(d)

Please see response to YUB-YEC-1-1(d).

(e)

Yukon Energy expects that provided that costs incurred are demonstrated to be prudently incurred that such costs would be included in rate base as part of the costs of the Project. Please see response to YUB-YEC-1-18(b).

(f) and **(h)**

A detailed NPV that compares the LNG installation (3 generators) to a complete new diesel replacement might be developed, subject to sorting out a number of assumptions, but would not provide a meaningful assessment of the Project economics for today's decision. To determine with any accuracy the lifecycle or NPV value of the Project would require an ability to not only forecast loads (extending out for the 40 year life of the Project) but also to forecast what other hydro enhancements, or renewable greenfield projects (such as hydro or wind) may be built (and the timing of such projects on the system) as well as costs of diesel and natural gas.

A NPV analysis that includes forecast non-industrial growth (but does not assume that other renewable options would be pursued to displace default thermal generation once larger and more stable loads materialize) would provide results that would make the Project look very attractive over its 40 year life so long as natural gas prices remain below diesel prices, but that would not be very realistic.

An assessment of the Project's near term benefits compared to the New Diesel alternative is provided in Table 4-3 in the Application which was updated in the response to YUB-YEC-1-13 based on updated Capital costs, updated LNG haul costs and updated diesel prices. Updated Table 4-3 indicates total net ratepayer fuel cost savings of $11.8 million compared to new diesel over the period from 2015 to 2018. Given that the gap in capital costs between the Project and the New Diesel Alternative is approximately $9.2 million[1], net fuel cost savings from the Project expected by 2018 will already cover the capital cost difference between the Project and the diesel alternative.

To the extent that diesel or other fuel prices are higher or lower than GRA approved fuel prices included in rates, these will still be ratepayer costs.

(g)

The proposed DCF will be adjusted at the time the Project comes into service and LNG/natural gas is available and used to meet thermal generation requirements in Yukon. LNG/natural gas will be treated in the same manner as diesel fuel for the purposes of administration of the DCF. Pending resolution of the proposed DCF/ERA, the ERA is expected to continue to operate based on the same principles as the DCF.

Costs related to LNG will be recovered through rates in the same manner as other YEC costs, with the fuel portion of costs being subject to the same DCF costing procedures as diesel fuel costs today (to address hydro-related variations in LNG generation requirements). Given the materially lower fuel cost for LNG compared to diesel, the implementation of the Project would reduce costs of fossil-fuel generation based on long term average hydro generation to be included in rates and would also reduce the financial impact of deferrals (or withdrawals) to (or from) the DCF.

[1] Please see YUB-YEC-13 (a) Attachment 1. The analysis is based on updated Project capital costs of $36.5 million provided in YUB-YEC-1-1(d) (for Project with first two gas fired generating units) plus a contingency estimate (as assumed in Updates Table 4-3) of $5.4 million for the third engine for a total of 13.1 MW; and the updated cost estimate provided in the YUB-YEC-13 for the New Diesel alternative (about $32.8 million).

TOPIC: **Capital costs**

REFERENCE: **Application, page 9**

Capital costs associated with the installation of the gas-fired generation units at Whitehorse are incrementally higher than would be required with new diesel generation units, due primarily to the requirement to develop related LNG storage, vapourization and truck offloading facilities. However, lower fuel costs of LNG compared to diesel generation yield material net fuel cost savings each year with the Project compared to the new diesel generation alternative.

PREAMBLE:

QUESTION:

a) Please provide an electronic version of the business case with formulae intact showing the above analysis.

ANSWER:

(a)

Please see UCG-YEC-1-2 Attachment 1 for the electronic version of the Table 4-3 with formulae intact. The table provides annual benefits from Project compared to the new diesel option. Please also see YUB-YEC-1-13(a) for the Updated Table 4-3 and related electronic version of this updated table.

Please also see YCS/LE-YEC-1-42 and YCS/LE-1-14(b) and (c) for the analysis with different LNG fuel costs and lower diesel alternative capital costs.

TOPIC: **Anticipated timelines**

REFERENCE: **Application, page 11 and 12**

PREAMBLE:

On page 12 of the Application, YEC states that the public comment on the revised project proposal is to conclude on December 20, 2014.

QUESTION:

a) As the date noted in the preamble is around the proposed in-service date for the project, is the date a typographical error?

ANSWER:

(a)

Yes, the reference to the public comment period on the revised project proposal being concluded on December 20, 2014 is a typographical error. The public comment period was extended by YESAB on December 17, 2013 and concluded on January 10, 2014.

TOPIC: **West Creek Hydro**

REFERENCE: **Application, page 19, footnote 20**

Yukon and Alaska recently signed an Economic Development Agreement with provision to look at the feasibility of transmission line connection between Skagway and the Yukon grid, including potential support for development of West Creek hydro.

PREAMBLE:

QUESTION:

a) Where does West Creek hydro fall within the planning horizon of YEC?

b) What must YEC accomplish for West Creek hydro to proceed? What criteria must be met?

ANSWER:

(a)

The West Creek project is at the early planning stage. Key tasks needed include building the hydrological record to further evaluate the power benefit. Neither environmental studies nor engineering studies have been done to date. As such, little is known on constructability and capital cost of the project. At this time, Yukon Energy does not have any information that would indicate whether the project is viable or not. Should the West Creek project and associated transmission infrastructure be developed, Yukon Energy anticipates the energy to be available in as early as 10 years from now.

(b)

Yukon Energy is not the proponent of the West Creek Project. At this stage, Yukon Energy's involvement includes technical support for the Borough of Skagway during the early stages of planning and engineering. The Borough currently needs to acquire the necessary funding to advance the project including the installation of water gauges and the development of a project plan. YEC must wait for Skagway to advance the project

and for the results of the recently released RFP for corridor infrastructure analysis (a joint initiative of the State of Alaska and the Government of Yukon).

TOPIC: **Techo Wind Farm**

REFERENCE: **Application, page 24, footnote 28**

…Yukon Energy is also pursuing a 20 MW wind farm at Techo (also known as Ferry Hill) in the Stewart Crossing area …

PREAMBLE:

QUESTION:

a) Please provide further information regarding the pursuit of this wind farm.

b) If YEC decided to go ahead with the wind farm, what would be the timing from that decision point to actual wind generation?

c) How would the costs for this project compare to the costs for the LNG option?

ANSWER:

(a)

Yukon Energy is continuing its wind data collection at Techo. After the 2014 winter, Yukon Energy will have a reasonably sized dataset to refine and confirm the power benefit previously estimated. Concurrently, Yukon Energy is reviewing capital cost estimates to take into account recent project experience with similarities in scope (e.g. substation, distribution line, etc.).

(b)

The development of a wind farm would require several steps. Engineering, baseline environmental and socio-economic studies would need to be initiated. In order to fully understand the potential impacts associated with the project, it is assumed that at least a full year of study would be required to complete the baseline and impact assessment studies. Although assumed to be a Designated Office screening, recent project experience suggests the regulatory review of the project could take up to one year after completion of the planning studies. Lastly, construction of the wind farm and modification

required to existing infrastructure such as substations may require up to two construction seasons. YEC would also examine going forward with a smaller wind project as loads justify the replacement of diesel/ gas generation.

(c)

The 20-year Resource Plan[1] reported a cost estimate for a 21 MW wind farm of $93.4 million (2010$). The annual energy after accounting for losses is estimated to be 55.8 GWh, and the reliable winter peak capacity contribution is estimated at 5 MW (for the 5 MW DRUPS required with the project). Due to the intermittent nature of the wind resource and lack of energy storage capability which translates in wind energy directly competing with legacy hydro energy during seasons when surplus hydro energy is available, levelized cost of energy (LCOE) was calculated at $0.40/kWh with Scenario A loads as forecast in the Resource Plan (assumed connection of Victoria Gold mine) with DSM, and was concluded to be more costly than diesel under the assumed loads. The LCOE for this wind project dropped to $0.21/kW.h if the same Scenario A load for 2019 (i.e., includes Victoria Gold and other mine loads as assumed) is extended to 2030. In summary, the 2011 Resource Plan analysis indicated that sustained (e.g., 20+ years) and higher grid loads than the current Application Base Case loads would be required for this capital intensive wind project to be feasible on the Yukon grid. Aside from the need for sustained and higher grid loads, this wind project had average 2015-2019 costs (when Victoria Gold loads were assumed) of 26-29 cents/kWh per unit of diesel displaced (assumed displaced 45 GW.h/year of default diesel generation).

In comparison, the 13.1 MW new natural gas generation Project set out in the Application is estimated to have a capital cost of approximately $41 million (assuming $36.5 million updated capital cost estimate per UCG-YEC-1-1(d) and the third engine assumed at $4.4 million). All of the Project's 13.1 MW contributes directly to reliable winter peak capacity, and the Project is justified based on its contribution to meeting current capacity planning shortfalls in a way that reduces ratepayers costs compared to relying on new default diesel capacity. The Project provides flexible and reliable generation as and when required to displace default diesel generation, with the capability (at a capacity factor of 91%) of generating up to 104 GWh per year. As demonstrated in the updated Table 4-3 (YUB-YEC-1-13(a)), the Project is expected to be required (under long-term average hydro generation and Base Case loads without

[1] Table 8-2 of *Overview of Yukon Energy's 2011 Resource Plan: 2011-2030 (the "Overview"*), which was filed in YEC's 2012/13 GRA proceeding in YECL-YEC-18(a) Attachment 1.

Alexco) to be required to generate only about 17 GW.h in 2015, increasing to about 31 GW.h in 2018, and these levels of default diesel generation displacement are more than sufficient to provide ratepayer savings in each year compared to the new diesel option.

Please see also YCS/LE-YEC-1-59(a) Attachment 1 for additional review of the wind project economics as examined in the 2011 Resource Plan.

TOPIC: **Hydro storage**

REFERENCE: **Application, page 30**

Operation of the new gas-fired generation capacity can be used, however, to assist in storing water at Aishihik and (to a much lesser extent) at Mayo during summer or other periods when thermal generation requirements are low, thereby allowing added hydro generation capability to be utilized in peak winter months

PREAMBLE:

QUESTION:

a) Does the above quote imply that thermal generation would displace hydro generation in the summer, which, in the end would displace thermal generation in the winter? Please show any cost/benefit analysis to support such a statement.

ANSWER:

(a)

Yes. Thermal generation using natural gas (with a much lower fuel cost than diesel) would displace hydro generation in the summer when this would enable the same hydro energy to be stored for future winter use to displace diesel generation. This operation makes economic sense when the natural gas, as a lower cost fuel, is thereby able to displace diesel generation through enhanced hydro storage.

Please see response provided to YUB-YEC-1-19 for additional analysis.

TOPIC: **Ratepayer impacts**

REFERENCE: **Application, page 32, Table 4.3**

PREAMBLE:

QUESTION:

a) Are other non-capital costs considered in the comparison, such as the handling, storage and vapourization of the LNG? Please explain.

ANSWER:

(a)

The analysis considers, but does not include, non-capital O&M costs other than fuel costs. Incremental O&M non-fuel cost are considered to be very similar for new diesel and the Project, and therefore would not have a material impact on the analysis in Table 4-3 which compares the costs of these two options. Accordingly, handling and storage O&M costs for diesel fuel are not included in Table 4-3, and similar costs (including vapourization O&M costs) for the Project are not included in Table 4-3.

TOPIC: **Risks**

REFERENCE: **Application, page 33**

Risks that increase annual capital cost charge penalties from the Project, for example: higher than assumed Yukon Energy capital costs of $38.8 million for the Project (which could reflect a wide variety of potential factors, including costs arising from delays), faster than assumed depreciation of these capital costs, and/or higher than assumed YEC annual costs of capital (costs for debt and equity) …

PREAMBLE:

QUESTION:

a) Please explain how the 40-year depreciation life was determined and provide all assumptions inherent in that estimate.

ANSWER:

(a)

The 40-year depreciation life is based on the following assumptions regarding the gas-fired engines and storage and vapourization facilities:

- New natural gas-fired engines are assumed to have an economic life of 40 years, based on expected average annual utilization of these assets. Assuming that the facilities will continue to be required for established backup capacity for the Yukon grid, it is expected that individual components will be replaced as they reach end of life and the Project facilities will not be decommissioned.

- The LNG Storage tank provider (Taylor Wharton) has confirmed that the LNG storage tanks will have a life greater than 30 years.

- The LNG Equipment provider (GP Strategies) and confirmed that it is reasonable to assume that the equipment to be provided will have a life of 40 years.

Please see also response to YCS/LE-YEC-1-15.

TOPIC: **Risks**

REFERENCE: **Application, page 33**

Page 33 of the Application discusses risk cases where capital costs are higher than proposed and where there are reductions in annual fuel price savings.

PREAMBLE:

QUESTION:

a) Please provide a similar analysis where forecast diesel generation is less by 5%, 10%, 20% and 25%.

ANSWER:

(a)

Table 4-6 and Figure 4-1 of the Application provides a range of minimum long-term diesel displacement in order for the Project still to be beneficial compared to new diesel units in the first full year of operation (2015).

Long-term average diesel generation forecast for 2015 is 17.0 GW.h as provided in Table 4-3 of the Application (Base Case with no Alexco).

- **Forecast Diesel Displacement 5% less than forecast in first year:** When the long-term average diesel generation to be displaced in 2015 is less by 5% it would equal 16.2 GW.h. Based on Table 4-6, under this scenario the Project is not beneficial compared to new diesel units in its first year of operation under the following cases:
    - If Project capital cost is higher by 15% or more and at the same time fuel cost savings are only 5.8 cents/kW.h or less [e.g., if diesel fuel cost for new diesel generation decreased from 24.6 cents/kW.h to 18.8 cents/kW.h or LNG delivered fuel cost increased to 19.3 cents/kW.h];

- If Project capital cost is higher by 20% or more and at the same time fuel cost savings are only 6.7 cents/kW.h or less [i.e., 4.4 cents below the forecast fuel cost savings of 11.1 cents/kW.h].

- **Forecast Diesel Displacement 10% or 20% less than forecast in first year:** When the long-term diesel generation to be displaced in 2015 is less by 10% or 20% it would equal about 15.3 GW.h and 13.6 GW.h accordingly. Based on Table 4-6, under these scenarios the Project is not beneficial compared to new diesel units in its first year of operation under the following cases:
  - If Project capital cost is higher by 10% or more and at the same time fuel cost savings are:
    - only 5 cents/kW.h or less (15.3 GW.h diesel displaced); or
    - only 5.7 cents or less (13.6 GW.h diesel displacement).
  - If Project capital cost is higher by 20% or more and at the same time fuel cost savings are:
    - only 7.1 cents/kW.h or less (15.3 GW.h diesel displaced); or
    - only 8.0 cents or less (13.6 GW.h diesel displacement).

- **Forecast Diesel Displacement 25% less than forecast in first year:** When the long-term diesel generation to be displaced in 2015 is less by 25% it would equal about 12.8 GW.h. Based on Table 4-6, under this scenario the Project is not beneficial compared to new diesel units in its first year of operation under the following cases:
  - If Project capital cost is higher by 5% or more and at the same time fuel cost savings are only 4.9 cents/kW.h or less.
  - If Project capital cost is higher by about 10% or more and fuel cost savings are only 6.1 cents/kW.h or less.
  - If Project capital cost is higher by about 15% or more and fuel cost savings are only 7.31 cents/kW.h or less.
  - If Project capital cost is higher by about 20% or more and fuel cost savings are only 8.5 cents/kW.h or less [i.e., 2.6 cents below the forecast fuel cost savings of 11.1 cents/kW.h].

TOPIC: **Capital cost risks**

REFERENCE: **Application, page 40**

Capital cost increase risks and other construction risks – May be expected for any project of this nature, location, and stage of development.

PREAMBLE:

QUESTION:

a) Please explain what YEC has done to determine the price, and therefore reduce the risk of cost overruns, for the natural gas generators, the unloading facility, the storage tanks and the vapourization unit.

ANSWER:

(a)

Please see response to YUB-YEC-1-1(d), which provides an updated Project capital cost estimate based on contractual costs for selected key long lead equipment (two GE engines [Gas Drive], three LNG storage tanks [499.5 m^3 total capacity], skid mounted vaporization and related equipment, and transformer), updated site layout design, and contractual costs for Project Management and Project Engineering.

Contingencies of $1.45 million are included in the update, with $1 million for construction contracts (primarily for as yet untendered civil, mechanical and electrical contracts estimates at $6.8 million as part of Site Development costs) and the balance for Engineering, Project Management and Owners as noted in Table 1.

TOPIC: **LNG fuel cost risks**

REFERENCE: **Application, page 40**

LNG Fuel Cost Risks – There is a risk that the assumed annual fuel cost savings with LNG compared to the new diesel alternative may be reduced due to changing market conditions (affecting the price of LNG compared to diesel), differences in efficiency, or due to increased LNG transportation costs (e.g., due to requirement to rely on Tridem trailers for transport in initial years due to A-Train trailers not being permitted for available and/or increased costs due to lower initial loads).

PREAMBLE:

QUESTION:

a) What analysis has YEC undertaken to test correlations and trends between LNG costs and diesel fuel costs? Please explain.

b) How is YEC able to determine and compare the efficiencies of the natural gas and new diesel gensets? How will YEC be able to determine the difference between the stated efficiencies and the actual operating efficiencies?

ANSWER:

(a)

Yukon Energy has relied upon forecasts prepared by third parties such as the US Energy Information Administration. As noted in the Application at page 40:

- LNG export opportunities from BC to Asia are based on the expectation of a sustained gap between high gas prices in Asia and much lower gas prices in North America. Gas prices in Asia tend to be linked to international crude oil prices, unlike the situation today in North America.

- Just prior to 2010, the gap increased dramatically between world crude oil prices and natural gas prices in North America, and crude oil price is expected, in the latest forecast outlook (April 2013) provided by the U.S. Energy Information

Administration, to remain well above North America natural gas prices through to at least 2040. These forecasts indicate crude oil prices to be 4 times that of North America natural gas price with the expectation that this condition would continue for a period extending beyond 2030.

YEC has also noted that several major international energy firms at this time are pursuing in BC opportunities for large scale LNG production for export to Asia. This activity supports the assumption that such plans reflect an expectation that BC/Alberta natural gas prices will remain well below world oil prices for the next few decades at least.

(b)

The efficiencies used by Yukon Energy reflect the manufacturer's guaranteed fuel efficiencies under a set of defined environmental conditions and fuel heat content. Please see response to YUB-YEC-1-34.

The actual fuel efficiency of the natural gas engines will be measured using a rigorous performance test within the first few months of operation. Natural gas flow meters have been purchased allowing on-going measurement of fuel consumption. Using the metered electrical output of the engine and the LNG fuel heat content the efficiency can be calculated on an on-going basis, as required, under a variety of different electrical loads and environmental conditions.