APPENDIX F:
Southeast Alaska & Yukon Economic Development Corridor: Financial Feasibility Analysis

Suite 500-280 Smith Street
Winnipeg, Manitoba
R3C 1K2
tel: (204) 942-0654
fax: (204) 943-3922
e-mail: intergroup@intergroup.ca

Memorandum

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FROM:	C. Osler, H. Najmidinov & M. Pollitt-Smith		
SUBJECT:	**Southeast Alaska & Yukon Economic Development Corridor: Financial Feasibility Analysis**		

This final working memo provides the financial feasibility analysis (including related sensitivity analysis) for the transmission interconnection between Southeast Alaska and Yukon as initially set out in the February 2, 2015 Interim Working Memo with edits to address comments arsing from the February 18, 2015 presentation to the Study Steering Committee.

1.0 BACKGROUND

The objective of the Southeast Alaska & Yukon Economic Development Corridor viability assessment (the "Project") is to determine the technical and financial conditions under which an electrical interconnection between Yukon and Southeast Alaska would be viable, and to identify the most viable scenario that represents the greatest net benefit to both governments.

The purpose of a transmission line such as the Project is to send electricity from one location to another in order to supply electrical load requirements at the least cost. In summary, to be financially viable, the transmission line to connect Southeast Alaska and Yukon requires the following conditions:

- A demand for power (a sufficient load) at one end; and
- A supply of power at the other end that can meet that demand on a cost competitive basis.

In the context of the Project, electricity moved over the interconnection is assumed to be used to displace higher cost thermal generation. It is also recognized that there exists the potential for power to move in both directions depending on load requirements and power availability.

In order to assess the viability of a potential transmission interconnection between Southeast Alaska & Yukon, the financial feasibility analysis considered the specific conditions (loads, system reliability, other potential uses of the corridor such as a telecommunications link) that would need to be present to make development of such a corridor work.

The financial feasibility analysis builds on the June 2014 workshop and background papers to define two development scenarios for the Project (see Attachment A for summary) and the load and competitive supply conditions provided at that time for this study, and on the technical feasibility analysis and cost estimates that were subsequently developed (see below). Assumptions and forecasts adopted for cruise ship loads (shoreside power loads) and Yukon grid loads remain as detailed in background documents for the June 2014 workshop and are not repeated in this memo.

The overall viability assessment of the Project has progressed as follows:

- On June 18, 2014, a one-day workshop ("June 2014 Workshop") was held in Whitehorse by the project team (including Yukon and Alaska representatives of utilities and government[1]) to assess conditions under which a interconnection may be viable. Building upon known or previously established energy forecasts and supply options, the following two "Development Scenarios" were defined in the workshop for the purpose of the current viability assessment [see Attachment A of this memo for details - a key finding of the Development Scenarios is that supplying the cruise ship load will be a fundamental requirement for the viability of the transmission line under any reasonably realistic scenario]:
    - Scenario 1: Development with West Creek Hydro Generation; and
    - Scenario 2: Yukon Surplus Hydro for Cruise Ship Loads

- On December 17, 2014, a presentation was provided with a technical feasibility analysis for the Project ("December 2014 Technical Presentation" and "Technical Feasibility Memorandum") which identified technically feasible options for the transmission line and reviewed the West Creek Hydro potential feasibility.
    - The December 2014 Technical Presentation divided the transmission line into three segments for the purpose of the design and routing. One route was selected for the Skagway to US/Canada border segment (19 km or about 12 miles) and the US/Canada border to Carcross segment (81 km or about 50 miles). The following options for transmission line routing were provided for the Carcross to Whitehorse segment (70 km or about 44 miles):
        - **Option A:** A new right of way generally following the South Klondike Highway and with wooden H-poles;
        - **Option B:** Re-building and expanding existing ATCO right of way with a single-pole wishbone transmission line and distribution under build; and
        - **Option C:** New right of way generally following White Pass & Yukon Route railway with wooden H-Poles.

[1] Government representatives from Yukon Government, Energy Branch; Southeast Conference (Alaska); and Alaska Energy Authority. Utility representatives from Yukon Energy Corporation (YEC); ATCO Electric Yukon (AEY); and Alaska Power and Telephone (AP&T). Documentation from this workshop is provided in the June 30, 2014 "Development Scenario Workshop Report" memo which includes in Attachment C the material provided at the workshop (including Background Papers on Long-term Fossil Fuel Generation Requirement Scenarios [including shoreside power requirement scenarios for Skagway/Haines] and Supply Options in Yukon and Southeast Alaska)

- The technical feasibility assessment also noted as follows regarding options for undertaking or optimizing the Project:
    - The transmission line can be built with and without fiber optic cable;
    - Substation requirements and costs
        - Yukon: No new substation is required in Whitehorse, however, Riverside Substation would require upgrades to accommodate the Project;
        - A new substation would be required in Skagway.
- The total length of the transmission line is estimated to be about 170 km (about 106 miles), including 151 km (about 94 miles) on the Canadian side of the border and 19 km (about 12 miles) on the Alaska side of the border.
- The December presentation and Technical Memorandum also reviewed the West Creek Hydro potential, including hydrology and power studies, review of site development layouts, and review of environmental and regulatory issues associated with West Creek Hydro development. As reviewed in Section 2.2 below, revised long term average energy generation estimates and revised costs estimates were provided for West Creek Hydro. It was also confirmed that development of this hydro project will likely require a minimum of 10 years, i.e., the earliest that it potentially could be in service is about 2025.
- The December 2014 Technical Presentation concluded that from a technical perspective, there are no significant issues associated with the transmission line design and routing, electrical system compatibility, or West Creek hydro development that would suggest the project is not technically feasible.

2.0 UPDATES TO FINANCIAL ASSESSMENT INFORMATION SINCE JUNE 2014

2.1 SKAGWAY-WHITEHORSE TRANSMISSION LINE COSTS

Transmission cost updates provided by Morrison Hershfield, in association with Dryden & LaRue, in January 2015 show the transmission line costs estimated to be between $108.6 million and $145.8 million (CAD, 2014$) depending on the Right of Way (ROW) selected and on whether the fibre option is included or excluded. The fibre option adds about $19-$23 million to the cost of the transmission line, and apparently is materially more costly than the current option[2] to install fibre as a stand alone project. Further detail regarding updated transmission line costs is summarized in Attachment D.

For the purpose of the financial feasibility analysis the lowest cost Project option was considered as the base case scenario for Project feasibility assessment (i.e., $108.6 million [CAD, 2014$] for Option A - new ROW along Highway and without fibre). This is higher than the initially assumed cost used at the June workshop (an assumed cost estimate of $84 million).

[2] See Annex D, which indicates cost in range of $9.5 million for fibre installation without use of transmission line.

2.2 WEST CREEK HYDRO

West Creek Hydro cost updates provided to InterGroup by Morrison Hershfield, in association with Access Consulting, indicate lower generation estimates and higher cost estimates for this project than the initial assumptions used at the June workshop:

- The December 2014 Technical Presentation provides updated analysis on West Creek Hydro average generation. [Attachment B of this memo provides details of updated West Creek Hydro generation estimates for the purpose of the financial feasibility analysis.]
- The following updates regarding West Creek Hydro generation and forecast use are noted:
  - A long-term average generation output of 106 GW.h over the 15 years record of water flows.
  - Long-term average annual generation as follows:
    - Generation of about 55 GW.h over the summer months (from June 1 to November 30); and
    - Generation of 50 GW.h in the winter months (December 1 to May 31).
  - Based on the above updated generation estimates and the earlier load forecasts for the Yukon grid (2030 forecast thermal generation with no mines, assuming no new renewable generation on the grid) and the Cruise Ships, West Creek Hydro could potentially displace during summer about 25 GW.h/year of diesel generation otherwise required for the Cruise Ships, and during winter about 47 GW.h/year of long-term average thermal generation (likely LNG supplied gas-fired generation) otherwise required for the Yukon grid (total thermal generation displacement of 72 GW.h/year - with line losses assumed at 5%, this corresponds to about 76 GW.h/year of West Creek Hydro generation or about 72% of the estimated long term average West Creek Hydro capability of 106 GW.h/year).
  - Based on these forecasts, West Creek Hydro would have about 30 GW/h/year long-term average surplus power (mainly from July through November) to accommodate future load growth.
- Updated cost estimates for West Creek Hydro show higher capital costs compared to what was assumed at the June 2014 Workshop (at that time assumed to be $140 million [$2014] based on a recent Municipality of Skagway application). The updated cost estimate for West Creek Hydro of $327 million Canadian dollars (2014$) is reviewed in detail in Attachment C, and reflects scaled up costs from the 1982-1983 R.W. Beck feasibility study using US CPI adjustments and January 2, 2015 US-CAD exchange rate (use of the US GDP deflator inflation adjustment for this period, which the Steering Committee has suggested, would reduce this cost to $279.0 million [CAD$2014]). It is understood that the recent AP&T 2014 FERC Application and 2012 Renewable Energy Fund Round 6 Grant Application by the Municipality of Skagway involved different assumptions regarding storage, power plant location and related costs[3].

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[3] See the December 2014 Technical Feasibility Memorandum (including Access Consulting Memorandum) for a more detailed review of the different layouts assumed for the 1982-83 Beck study and the AP&T 2014 FERC Application, e.g., the earlier study assumed a powerhouse near the mouth of West Creek on the Taiya River while the 2014 FERC Application assumed a powerhouse near tidewater on the Taiya Inlet. More importantly, the AP&T 2014 FERC Application and the 2012 Funding Application by the Municipality of Skagway each assumed a project that would primarily supply the summer cruise ship loads (about 27 GW.h/yr assumed sales out of 110 GW.h/year potential generation) without a large storage dam. The 2012 Application to Alaska Energy Authority (AEA) assumed the need for an AEA grant equal to 80% of the estimated project cost of $140 million (US$). The Round 6

- It is noted that the current study has not been done to evaluate West Creek Hydro, either the 1982-1983 concept or the concept proposed in the recent AP&T FERC Application.
    - West Creek Hydro is reviewed in this study as a potential hydro supply project, including financial feasibility assessment, solely to inform (based on current information available to the study team) the investigation of the transmission corridor based on potential power availability for a West Creek Hydro project.
    - In the context of the current transmission corridor study, a West Creek Hydro project would need to include material hydro storage (as assumed in the 1982-83 Beck study) in order to offer any potentially significant feasibility benefit to the Southeast Alaska-Yukon transmission corridor, i.e., without such hydro storage, West Creek Hydro generation would be very sharply curtailed during the winter months (e.g., January to May in particular) which is the only time period when this new transmission access is currently forecast to facilitate use of this Southeast Alaska hydro power to displace thermal generation on the Yukon grid[4].

3.0 DEVELOPMENT SCENARIOS - FINANCIAL FEASIBILITY ANALYSIS

The financial feasibility analysis assesses the viability of the interconnection Project under each of the two Development Scenarios defined in the June 2014 workshop (see Attachment A), under the Base Case assumptions (see Attachment E) as well as under the following sensitivities:

- Impact of Changes in assumed Capital Costs;
- Impact of Changes in assumed loads and power sales rates; and
- Impact of Changes in assumed Average Cost of Capital (6.5% and 4.5%).

As reviewed in Attachment E, the financial feasibility analysis for each Development Scenario and sensitivity assesses the potential recovery of Project costs through charges for electricity transmitted over the interconnection. Assumed Project charge rates are based on assumed market constraints as well as estimated Project costs as reviewed below. In each case, required annual government funding support is estimated to the extent that assumed charge rates are not able to recover estimated Project costs.

The analysis assumes, for simplicity, constant annual costs and revenues (over the assumed economic lives) to reflect the preliminary nature of any assessment based on current information regarding the interconnection Project and potential forecasts that affect Project feasibility:

- **Present value (PV) costs for the Project and West Creek Hydro stated as fixed annual costs**: As reviewed in Attachment E, PV costs for the Project and West Creek Hydro are each stated in CAD, 2014$[5], including the assumed capital development cost and the assumed O&M costs over the relevant economic life (55 years for the Project and 90 years for West Creek

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Grant Application by Municipality of Skagway is available though Alaska Industrial Development and Export Authority ftp site at ftp://www.aidea.org/REFund/Round%206/Applications/918_West%20Creek%20Hydroelectric%20Project/. The information regarding AP&T application before FERC is available at: http://www.gpo.gov/fdsys/pkg/FR-2014-04-10/html/2014-08056.htm.

[4] As reviewed in the December 2014 Technical Feasibility Memorandum (including Access Consulting Memorandum), average monthly flows are below the yearly average (8.2 m^3/s) from January to May [0.6 to 0.7 m^3/s from January to March, 1.3 m^3/s in April and 5.2 m^3/s in May] and from October to December [6.2 m^3/s in October, and 1.1 to 2.9 m^3/s in the remaining two months].

[5] Canadian dollar at $1 US = $1.16 CAD based on exchange rate as of January 1, 2015 (Band of Canada).

Hydro).[6] Annual PV costs are assumed constant [in CAD, 2014$] over the respective economic lives (for the Base Case assumptions, at $4.649 million/year for the Project and $13.280 million/year for West Creek Hydro)[7]. This approach ignores normal utility rate recovery for such a Project which requires higher annual costs at the outset that decline over the economic life.

- **Assumed constant annual generation, loads and sales rates**: For simplicity, financial feasibility is assessed based on assumed constant annual generation, loads and sales rates (in real CAD, 2014$). This approach removes the complexities of varying annual forecasts over the respective economic lives of the Project and West Creek Hydro, and assumes that the analysis is conservative to the extent that Project use tends to improve over the economic life due to Yukon grid load growth. If the Project proceeds, further feasibility analysis will be needed to confirm that assumed conditions over the economic life will continue to sustain Project feasibility.
- **Lifecycle Cost of Energy (LCOE) in $/kW.h:** LCOE costs for the Project or West Creek Hydro reflect the respective PV annual costs divided by the relevant assumed constant annual Project load (i.e., electricity sales transmitted over the interconnection) or West Creek Hydro generation sales used to displace thermal generation in Alaska and Yukon. See Attachment E for specifics for Scenario 1 and Scenario 2.
- **Assumed West Creek Hydro sales rates (Scenario 1)**:
  - **Cruise Ship Sales**: $0.27/kW.h (based on assumed Cruise Ship purchase power rate).
  - **Yukon Grid Sales**: $0.139/kW.h (based on assumed sales of 47 GW.h/year and balance of West Creek Hydro PV annual costs less assumed sales revenues from Cruise Ships).
- **Assumed rates for electricity transmitted by the Project:** The Project's constant annual charges [CAD, 2014$] for electricity transmitted are estimated as follows:
  - **Scenario 1:**
    - **Yukon Grid Sales to Cruise Ships**: $0.140/kW.h (reflects the assumed Cruise Ship purchase power rate of $0.27/kW.h less the assumed Yukon grid average rate for summer sales of $0.13/kW.h for Scenario 1).
    - **Purchase by Yukon from West Creek Hydro**: two rates are estimated:
      - <u>Maximum Rate for the Project</u>: Yukon maximum rate for winter power purchases ($0.165/kW.h for Scenario 1) less the applicable West Creek Hydro sales rate to Yukon (based on annual West Creek Hydro annual costs net of West Creek Hydro revenue from sales to Cruise Ships).
      - <u>Residual Rate to recover LCOE</u>: lesser of the Maximum Rate and the rate needed to recover annual Project PV costs net of estimated revenues from Yukon sales to Cruise Ships.
  - **Scenario 2**:
    - **Yukon Grid Sales to Cruise Ships**: two rates are estimated:

[6] Under Base Case assumptions per Annex E, the overall PV costs [CAD, 2014$] over the economic life are $115.4 million for the Project and $373.0 million for West Creek Hydro.
[7] For comparison, US$ values approximate $4.0 million/year for the Project and $11.45 million/year for West Creek Hydro.

- Maximum Rate for the Project: $0.180/kW.h (reflects the assumed sales rate to Cruise Ships of $0.27/kW.h, less the assumed Yukon grid average rate charged for summer sales ($0.09/kW.h for Scenario 2).
- Residual Rate to recover LCOE: lesser of the Maximum Rate and the rate to recover annual Project PV LCOE costs ($0.155/kW.h for Scenario 2).

3.1 SCENARIO 1 ASSESSMENT - DEVELOPMENT WITH WEST CREEK HYDRO GENERATION

Development Scenario 1 focuses on development of the Project transmission corridor to supply surplus power from the proposed West Creek Hydro project near Skagway, Alaska to Whitehorse to displace growing thermal generation required on the Yukon grid in winter months and to provide hydro power to cruise ship loads in Skagway in summer months. Under this scenario the construction of the Project would be timed such that it is available when the West Creek Hydro project is commissioned (i.e., the scenario in effect assumes the Project is viable only with a West Creek Hydro project).

3.1.1 Development Scenario 1: Base Case Financial Feasibility Analysis

The Base Case financial feasibility analysis for Development Scenario 1 assumes that 47 GW.h/yr of West Creek Hydro sales are transmitted to the Yukon grid during winter months and 5 GW.h/yr of Yukon surplus hydro and backup LNG generation sales are transmitted to Alaska Cruise Ships during summer months. Development Scenario 1 assumes Project in-service no sooner than 2025, and reflects forecast loads for 2030 assuming no new mines connected to the Yukon grid (connection of new mine loads would improve Project use, assuming no offsetting new renewable generation supply on the Yukon grid).

Table 1 provides the Base Case financial feasibility assessment of Scenario 1, including review of assumed West Creek Hydro costs and revenues. Highlights include the following:

- LCOE for Project "sales" are $0.089/kW.h [CAD, 2014$], assuming annual sales transmitted over the interconnection of 52 GW.h/year and annual PV costs of $4.649 million.
- Estimated annual Project revenues are $1.925 million [CAD, 2014$], assuming $0.7 million recovered for transmittal of 5 GW.h for Yukon summer sales to Cruise Ships and $1.225 million recovered for transmittal of 47 GW.h for West Creek Hydro winter sales to the Yukon grid.
    - o Project revenues are constrained by the assumed cost for West Creek Hydro generation sales to Yukon, i.e. even after recovery of $6.75 million for summer sales to Cruise Ships (25 GW.h at $0.27/kW.h), a rate of $0.139/kW.h is required to recover the balance of West Creek Hydro PV annual costs [$6.53 million] from winter sales to the Yukon grid.
    - o Based on the assumed Yukon grid maximum rate of $0.165/kW.h for power purchases (assuming LNG generation displacement), only $0.026/kW.h remains to be charged for Project transmission of 47 GW.h of West Creek Hydro winter sales to the Yukon grid.
- The overall result is that Project viability for Scenario 1 under Base Case assumptions requires external funding support [CAD, 2014$] equal to 59% of PV annual costs ($2.724 million/year)[8].

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[8] Approximates $2.35 million in US$2014 based on US-CAN dollar conversion at $1 US=$1.16 CAD.

Table 1: Development Scenario 1 – Financial Feasibility
Base Case Analysis [CAD, 2014$]

	Scenario 1 Base Case	
	Intertie Project	**West Creek Hydro**
Economic Life (years)	55	90
Cost of Capital (%/year)	5.45%	5.45%
Real Discount Rate (2%/yr inflation)	3.38%	3.38%
PV Costs (CAD, 2014$million)		
Capital	108.612	327.036
O&M over economic life	6.783	45.923
Total	115.395	372.959
Annual Costs each year (CAD, 2014$million)	$4.649	$13.280
Thermal Loads Displaced each year (GW.h/yr)		
Cruise Ships	5.0	25.0
Yukon Grid	47.0	47.0
LCOE for sales (CAS, 2014$/kW.h)	$0.089	$0.184
Sales Rate (CAD, 2014$/kW.h)		
Cruise Ships purchase rate (displace diesel)	0.27	0.27
Yukon av summer sale rate (w losses, LNG backup)	0.13	
Yukon max winter purchase rate (displace LNG)	0.165	
West Creek Hydro rate for winter sales to Yukon	-	0.139
Intertie Use Rates [CAD, 2014$/kW.h])		
Summer Sales to Alaska Cruise Ships		
Assumed Rate ($/kW.h)	0.140	0.27
Winter Sales to Yukon Grid		
Residual Rate to recover LCOE ($/kW.h)	0.026	
Maximum Rate for Project ($/kW.h)	*0.026*	
Annual Revenues (CAD, 2014$million)		
Alaska Cruise Ships thermal displacement	0.700	6.750
Yukon Grid thermal displacement (Residual Rate)	1.225	6.530
Total Annual Revenues (Residual Rate)	1.925	13.280
Total Annual Revenues (Maximum Rate)	*1.925*	
Unrecovered Annual Cost (CAD, 2014$million/yr)	2.724	0.000
Percent of Annual Cost (%)	*59%*	*0%*
Funding Support Needed (CAD, 2014$million/yr)	2.724	
PV Annual Surplus at Max Rates (CAD, 2014$million/yr)	0.000	
Percent of Annual Cost (%)	*0%*	

3.1.2 Scenario 1: Financial Feasibility Sensitivity Analysis

Table 2 provides financial feasibility sensitivity analysis for Scenario 1, indicating the extent to which estimated unrecovered PV annual costs vary from the $2.394 million estimated for the Base Case assumptions. Highlights include the following:

- **Project Capital Costs**: +/-15% variance has modest impact
- **West Creek Hydro Capital Costs**: these cost estimates are subject to a wide range of possible variance as reviewed in Attachment C, and cost reductions can have material impacts on financial viability.
    - A reduction of 10% from the Base Case cost reduces unrecovered PV annual costs to $1.396 million (adjustment of the capital cost using US GDP deflator rather than US CPI would reduce the Base Case costs more than 10% [i.e., 15%] and unrecovered PV annual costs would approximate $0.775 million),
    - A reduction of 21% or more from the Base Case cost yields Project revenues adequate to recover PV annual Project costs.
- **Cost of Capital**: changes in cost of capital can have material impacts on financial feasibility:
    - Increase of the nominal cost of capital to 6.5% [versus 5.45% in the Base Case] increases unrecovered PV annual costs to $6.717 million;
    - Reduction of the nominal cost of capital to 4.5% yields a PV Annual Surplus at Maximum Rates of $0.642 million.
- **Power Sales Volumes**: changes in power sales volumes can have material impacts on financial feasibility:
    - Ability to displace 60 GW.h of Yukon thermal generation (versus 49 GW.h assumed in the Base Case) reduces unrecovered PV annual costs to $0.579 million;
    - In contrast, reductions in assumed loads sent to Yukon to 40 GW.h sales increases unrecovered PV annual costs to $3.879 million;
    - Removal of Cruise Ship loads for West Creek Hydro and Yukon sales increases unrecovered PV annual costs to $9.184 million.
- **Power Sales Rates**: changes in power sales rates [CAD, 2014$] can have material impacts on financial feasibility:
    - Increase of the Yukon maximum rate for power purchase (reflects thermal fuel and O&M costs displaced) to $0.20/kW.h [versus $0.165/kW.h in the Base Case] reduces unrecovered PV annual costs to $1.079 million; reduction of this maximum rate to $0.14/kW.h increases unrecovered PV annual costs to $3.899 million.
    - Increase of the Cruise Ship rate for power purchase to $0.30/kW.h [versus $0.27/kW.h in the Base Case] reduces unrecovered PV annual costs to $1.824 million; reduction of this maximum rate to $0.24/kW.h increases unrecovered PV annual costs to $3.624 million.

In summary, Table 2 highlights the sensitivity of the Project financial feasibility analysis for Development Scenario 1 to changes in specific Base Case assumptions. Combined changes in several of the identified factors could increase or offset the sensitivities noted, e.g., at the assumed power sales rates and capital costs, the Development Scenario 1 would recover PV Annual Costs with West Creek capital costs 15% lower (at $278 million) and Yukon grid thermal displacement 5 GW.h/year higher (at 52 GW.h/year).

Table 2: Development Scenario 1 – Financial Feasibility Sensitivity Analysis [CAD, 2014$]

Scenario 1 - Sensitivity Analysis	Unrecovered PV Annual Costs [CAD, 2014$ million/year]	PV Annual Surplus at Maximum Rates [CAD, 2014$ million/year]
Base Case Financial Feasibility	2.724	0.000
Project Capital Cost Variance:		
Project Capital Cost +15% [$125 M]	3.381	0.000
Project Capital Cost -15% [$92 M]	2.068	0.000
West Creek Hydro Capital Cost Variance:		
West Creek Capital Cost +25% [$409 M]	6.044	0.000
West Creek Capital Cost -10% [$294 M]	1.396	0.000
West Creek Capital Cost -21% [$258 M]	0.000	0.065
West Creek Capital Cost -25% [$245 M]	0.000	0.596
West Creek Capital Cost -50% [$163 M]	0.000	3.916
Cost of Capital		
Nominal cost of capital at 6.5% (real 4.41%)	6.717	0.000
Nominal cost of capital at 4.5% (real 2.45%)	0.000	0.642
Power Sales Volumes		
WC sales ships 25 GW.h, Yukon 81 GW.h	0.000	2.886
WC sales ships 25 GW.h, Yukon 65 GW.h	0.000	0.246
WC sales ships 25 GW.h, Yukon 60 GW.h	0.579	0.000
WC sales ships 25 GW.h, Yukon 55 GW.h	1.404	0.000
WC sales ships 25 GW.h, Yukon 40 GW.h	3.879	0.000
WC sales ships 20 GW.h, Yukon 53 GW.h	2.384	0.000
WC sales Yukon 53 GW.h (No Cruise Ships)	9.184	0.000
Power Sales Rates		
Yukon grid max purchase rate $0.20/kW.h	1.079	0.000
Yukon grid max purchase rate $0.18/kW.h	2.019	0.000
Yukon grid max purchase rate $0.14/kW.h	3.899	0.000
Cruise Ship purchase rate 0.30/kW.h	1.824	0.000
Cruise Ship purchase rate 0.24/kW.h	3.624	0.000
Yukon grid summer sales rate $.165/kW.h	2.899	0.000
Yukon grid summer sales rate $.10/kW.h	2.574	0.000

3.2 SCENARIO 2 ASSESSMENT - DEVELOPMENT WITH YEC SUMMER HYDRO SURPLUS AND SKAGWAY CRUISE SHIP LOADS

Development Scenario 2 focuses on development of the Project transmission corridor in advance of any new hydropower developments in the Upper Lynn Canal area (such as West Creek hydro generation project). The transmission corridor would be developed initially to transmit surplus summer power from Whitehorse to Skagway to displace summer Cruise Ship diesel generation loads as soon as shore power is available in Skagway.

3.2.1 Development Scenario 2: Base Case Financial Feasibility Analysis

The Base Case financial feasibility analysis for Development Scenario 2 assumes that 30 GW.h/year of Yukon surplus hydro and backup LNG generation sales are transmitted to Alaska Cruise Ships during summer months. Development Scenario 2 assumes Project in-service no sooner than 2020, and reflects forecast loads for the 2020 to 2030 time period assuming no new mines connected to the Yukon grid (connection of new mines could reduce surplus hydro supply and thereby reduce Project viability, unless offsetting new renewable generation supply occurred on the Yukon grid).

Table 3 provides the Scenario 2 Base Case financial feasibility analysis. Highlights include the following:

- LCOE for Project "sales" are $0.155/kW.h [CAD, 2014$], assuming annual sales transmitted over the interconnection of 30 GW.h/year and annual PV costs of $4.649 million.
- Estimated annual Project revenues at residual rates (i.e., residual rate charge to Cruise Ships to recover LCOE) are sufficient to recover fully the Project PV annual costs. The key factor affecting this recovery of PV annual costs is the margin between the estimated Yukon grid average rate for summer sales ($0.09/kW.h) and the assumed Cruise Ships purchase power rate ($0.27/kW.h). Under the Base Case assumptions, this margin is $0.18/kW.h, and thus exceeds the LCOE threshold for the Project sales ($0.155/kW.h).[9]
- Table 3 shows two rate revenues: "Residual rates" are limited to LCOE recovery, i.e., $0.155/kW.h; "Maximum rates" equal the full margin over grid rates ($0.18/kW.h).
- The overall result is that Project viability under Scenario 2 and Base Case assumptions does not require any government funding support, and the PV annual surplus revenue at maximum rates [CAD, 2014$] equals 16% of PV annual costs ($0.751 million per year).[10]

[9] This feasibility analysis does not address how the "extra revenue in excess of costs and charge rates" (e.g., $0.025/kW.h in the Base Case for Scenario 2) is allocated, e.g., reduced charge rate to Cruise Ships or increased Yukon grid rates for summer sales.

[10] Approximates $0.65 million in US$2014 based on US-CAN dollar conversion at $1 US=$1.16 CAD.

Table 3: Development Scenario 2 – Financial Feasibility
Base Case Analysis [CAD, 2014$]

	Base Case **Intertie Project**
Economic Life (years)	55
Cost of Capital (%/year)	5.45%
Real Discount Rate (2%/yr inflation)	3.38%
PV Costs (CAD, 2014$million)	
Capital	108.612
O&M	6.783
Total	115.395
Annual Costs (CAD, 2014$million)	$4.649
Thermal Loads Displaced (GW.h/yr)	
Cruise Ships	30.0
LCOE for sales (CAD, 2014$/kW.h)	$0.155
Sales Rate (CAD, 2014$/kW.h)	
Cruise Ships purchase rate (displace diesel)	0.27
Yukon av summer sale rate (w losses, LNG backup)	0.09
Intertie Use Rates [CAD, 2014$/kW.h])	
Summer Sales to Alaska Cruise Ships	
Residual Rate to recover LCOE ($/kW.h)	0.155
Maximum Rate for Project ($/kW.h)	*0.180*
Annual Revenues (CAD, 2014$million)	
Residual Rate revenues to recover LCOE	4.649
Maximum Rate revenues	*5.400*
Unrecovered Annual Cost (CAD, 2014$million/yr)	0.000
Percent of Annual Cost (%)	*0%*
Funding Support Needed (CAD, 2014$million/yr)	0.000
PV Annual Surplus at Max Rates (CAD, 2014$million/yr)	0.751
Percent of Annual Cost (%)	*16%*

3.2.2 Scenario 2: Financial Feasibility Sensitivity Analysis

Table 4 provides financial feasibility sensitivity analysis for Scenario 2, indicating the extent to which the PV annual surplus revenue at maximum rates varies from the $0.751 million estimated for the Base Case assumptions. Highlights include the following:

- **Project Capital Costs**: +/-15% variance has modest impact (PV annual surplus revenue is reduced, but is still positive, with 15% increase in Project capital costs).
- **Cost of Capital**: changes in cost of capital can have material impacts on financial feasibility:
    - o Increase of the nominal cost of capital to 6.5% [versus 5.45% in the Base Case] results in unrecovered PV annual costs of $0.157 million;
    - o Reduction of the nominal cost of capital to 4.5% increases PV annual surplus revenues to $1.510 million.
- **Power Sales Volumes**: reductions in power sales volumes below the 30 GW.h/yr assumed in the Base Case can have material impacts of financial feasibility:
    - o Reduction to 25 GW.h/yr removes the PV annual surplus revenue and results in unrecovered PV annual costs of $0.149 million (3% of PV Annual Costs).
    - o Reduction to 20 GW.h/yr results in unrecovered PV annual costs of $1.049 million.
    - o In summary, each 5 GW.h/yr reduction in power sales volume reduces PV annual cost recovery by $0.9 million or 19.4% of PV Annual Costs.
- **Power Sales Rates**: changes in power sales rates [CAD, 2014$] can have material impacts of financial feasibility:
    - o Increase of the Yukon grid average rate for summer sales (reflects mix of surplus hydro and LNG fuel and O&M generation costs) to $0.15/kW.h [versus $0.09/kW.h in the Base Case] results in unrecovered PV annual capital costs of $1.049 million, i.e., each $0.03/kW.h increase in this average rate reduces Project annual cost recoveries by $0.9 million (assuming 30 GW.h/yr sales).
    - o Increase of the Cruise Ship rate for power purchase to $0.30/kW.h [versus $0.27/kW.h in the Base Case] increases PV annual surplus revenues to $1.651 million; reduction of this maximum rate to $0.24/kW.h results in unrecovered PV annual costs of $0.149 million.

The above analysis highlights the sensitivity of the Project financial feasibility analysis for Development Scenario 2 to changes in specific Base Case assumptions. Combined changes in several of the above factors could increase or offset the sensitivities noted. By way of example, at the assumed capital costs the impact of two possible combined changes in sales volumes and rates is noted below:

- Sales to Cruise Ships at 25 GW.h/year, purchase rate $0.25/kW.h, Yukon sale rate at $0.12/kW.h: unrecovered PV Annual Cost at $1.399 million (30% of PV Annual Cost).
- Sales to Cruise Ships at 20 GW.h/year: purchase rate $0.25/kW.h, Yukon sale rate at $0.08/kW.h: unrecovered PV Annual Cost at $1.249 million (27% of PV Annual Cost).

Table 4: Development Scenario 2 – Financial Feasibility Sensitivity Analysis [CAD, 2014$]

Scenario 2 - Sensitivity Analysis	Unrecovered PV Annual Costs [CAD, 2014$ million/year]	PV Annual Surplus at Maximum Rates [CAD, 2014$ million/year]
Base Case Financial Feasibility	**0.000**	**0.751**
Project Capital Cost Variance:		
Project Capital Cost +15% [$125 M]	**0.000**	**0.094**
Project Capital Cost -15% [$92 M]	**0.000**	**1.407**
Cost of Capital		
Nominal cost of capital at 6.5% (real 4.41%)	**0.157**	**0.000**
Nominal cost of capital at 4.5% (real 2.45%)	**0.000**	**1.510**
Power Sales Volumes		
Summer sales to Cruise Ships 25 GW.h	**0.149**	**0.000**
Summer sales to Cruise Ships 20 GW.h	**1.049**	**0.000**
Summer sales to Cruise Ships 15 GW.h	**1.949**	**0.000**
Power Sales Rates		
Yukon grid summer sales rate $0.15/kW.h	**1.049**	**0.000**
Yukon grid summer sales rate $0.12/kW.h	**0.149**	**0.000**
Yukon grid summer sales rate $0.06/kW.h	**0.000**	**1.651**
Cruise Ship purchase rate at 0.30/kW.h	**0.000**	**1.651**
Cruise Ship purchase rate at 0.24/kW.h	**0.149**	**0.000**

4.0 SUMMARY AND CONCLUSIONS

In order to assess the viability of a potential transmission interconnection between Southeast Alaska and Yukon, a financial feasibility assessment was undertaken considering the specific conditions that would need to be present to make the development of such a corridor work.

Initial Assessments Undertaken in June 2014

Initial assessments undertaken in June 2014 defined and confirmed two Development Scenarios for the purpose of the feasibility assessment.

- Scenario 1: Development with West Creek Hydro Generation; and
- Scenario 2: Yukon Surplus Hydro for Cruise Ship loads.

A key finding of the initial assessments undertaken in June 2014 was that supplying the cruise ship load would be a fundamental requirement for the viability of the transmission line under any reasonably realistic scenario.

Results of Financial Feasibility Assessment undertaken in January 2015

Building on the earlier analysis undertaken for the June 2014 workshop (including background papers) and on the technical feasibility analysis and cost estimates subsequently developed, the financial feasibility assessment indicates as follows for each of the development scenarios considered:

- **Project viability for Development Scenario 1:** Under Base Case parameters Scenario 1 is not viable without external funding support [CAD, 2014$] equal to 59% of present value (PV) annual costs ($2.724 million/year)[11]. This assessment reflects the following:
  - Higher capital cost estimates for the West Creek Hydro Project and lower average annual generation estimates.
  - Estimated Project revenues are constrained by the estimated cost for West Creek Hydro generation sales to Yukon, and the maximum rate that YEC can pay for thermal generation displaced by West Creek Hydro sales.

- **Project viability for Development Scenario 2:** Under Base Case parameters Scenario 2 is viable without government funding support, and the present value (PV) annual surplus revenue at maximum interconnection use rates [CAD, 2014$] equals 16% of PV annual costs ($0.751 million per year)[12]. The key factors affecting the recovery of PV annual costs is the assumed volume of summer sales (30 GW.h/year) and the assumed spread between the estimated Yukon grid average rate for summer sales and the estimated Cruise Ships' purchase power rate.

In summary, under Base Case conditions, proceeding with the Project on its own as per Scenario 2 is financially feasible provided there is sufficient summer surplus hydro power and low cost thermal generation backup (e.g., LNG) available in Yukon. Scenario 2 requires Cruise Ship loads of about 30 GW.h/year to be supplied with shore power in summer months at the Base Case power purchase rates. However, the Project is not currently financially viable with Scenario 1 Base Case conditions due to the relatively high estimated cost of power delivered by West Creek Hydro under the updated analysis.

Sensitivity analysis undertaken for each Development Scenario indicates that changes in power sales volumes, power sales rates and the cost of capital can have a material impact on financial feasibility. Changes in capital cost for the Project have only a modest impact. For Scenario 1, financial feasibility of the Project is very sensitive to the development costs for West Creek Hydro.

The financial feasibility has assumed a cost of capital based on recent YEC experience, as well as Project rates that are levelized over the Project economic life. Confirmation of specific ownership, financing and rate arrangements for the Project would be required in order to confirm the Project's financial feasibility.

[11] Approximates $2.35 million in US$2014 based on US-CAN dollar conversion at $1 US=$1.16 CAD.

[12] Approximates $0.65 million in US$2014 based on US-CAN dollar conversion at $1 US=$1.16 CAD.

Project viability under Scenario 2 is based upon a long-term opportunity to transmit surplus power during the summer months from the Yukon grid to Skagway Cruise Ships. Sensitivity analysis confirms that financial feasibility of the Project with the Scenario 2 Development Scenario is reasonably robust provided that adequate Cruise Ship purchase power volumes and rates are confirmed prior to actual development. In this regard, the following can be noted with regard to the likely sustainability of Yukon grid surplus renewable energy generation and LNG backup generation capacity:

- The Yukon grid tends to have surplus renewable generation in summer months due to low average loads and excess renewable hydro generation. This is not expected to change in the foreseeable future.
- Although load growth on the Yukon grid by itself tends to reduce the summer renewable surplus generation, future development of new renewable generation (to meet winter demands) is reasonable to expect with ongoing load growth.
- Access to summer sales in Alaska as assumed under Development Scenario 2 will enhance the viability of new renewable generation on the Yukon grid (to the extent that the Alaska sales enhance use of the new renewable generation).
- Development of the Project under Scenario 2 would also create specific new opportunities for future hydro development in Southeast Alaska and northwest BC.
- Backup LNG generation capacity on the Yukon grid is also likely to increase in future in step with ongoing planned retirement of existing diesel generation units plus the need to increase backup capacity due to ongoing increases in the winter peak load.

In conclusion, Development Scenario 2 offers conditions where the interconnection Project between Yukon and Southeast Alaska would be financially viable and make sense to pursue in the near term.

This project remains challenging, however, for any single entity to pursue, given the multiple jurisdictions and participants. The next steps to proceed with Development Scenario 2 for the earliest potential in-service of the interconnection Project (e.g., 2020) would therefore likely require a joint Alaska-Yukon initiative to confirm if the relevant conditions to proceed can be established, including the following:

1. Confirmation of financial feasibility conditions, including:
    a. arrangements as needed for adequate Cruise Ship purchase power volumes and rates to be secured and supplied through shore power by 2020 and for a reasonable period thereafter;
    b. arrangements as needed to define basic provisions for securing Yukon Energy surplus summer hydro and backup LNG generation, and the future adequacy of such generation to supply the potential Cruise Ship loads (taking into account capacity related requirements for multiple concurrent Cruise Ship loads); and
    c. arrangements as needed to define basic provisions for the Project regarding ownership, financing, basis for rate charges for interconnection use (and how these may change as conditions change), and extent if any of government funding to support.
2. Confirmation of permitting and development requirements and timelines for the Project, preparation of the required socio-environmental submissions, and finalization of feasibility cost estimates based on the Project as defined for such submissions.

ATTACHMENT A – SUMMARY OF JUNE 2014 WORKSHOP

The June 18, 2014 Workshop (and the related workshop memo of June 30, 2014) summarized the two defined Development Scenarios and other key financial feasibility assessment information as set out below. As per this study's workplan, these Development Scenario parameters were "fixed" for the remainder of this study.[13]

SCENARIO 1 – DEVELOPMENT WITH WEST CREEK HYDRO GENERATION

This development scenario is focused on development of the transmission corridor that would supply surplus power to Whitehorse from the proposed West Creek Hydro project near Skagway, Alaska in order to displace growing thermal generation requirements on the Yukon grid in the winter months.

Scenario 1 - Development with West Creek Hydro Generation

Whitehorse, Yukon **Skagway, Alaska**

← About 54 GW.h/yr from Alaska to Yukon

Need sufficient fossil fuel displacement opportunity
- New loads needed on grid of 25-50 GW.h/yr to proceed within next decade

Financial & Economics viability issues (beyond timing):
- Expected cost savings from fossil fuel displacement
- Competitive renewable cost options (e.g., other hydro sites)
- Supply security & charges for delivered West Creek hydro

Confirm West Creek Hydro volumes, timing and costs
- About 134 GWh/yr generation, less 80 GW.h/yr June to Nov (not needed in Yukon)

Financial & Economics viability issues (beyond timing):
- Net power charges to cruise ships & sustainability of loads
- Overall capital costs for new hydro & transmission
- Financing, ownership and cost recovery arrangements

In summary:

- Potential available generation from West Creek of 134 GW.h/year
  - It was concluded that a reasonable assumption of time needed to develop the West Creek hydro project (planning, permitting and construction) would be about 10 years.
  - Available information for a 25 MW West Creek Hydro project estimates average generation over 15 water years of record at 134 GW.h/yr (range of 110 to 160 GW.h/yr), with about 80 GW.h on average from June 1 to November 30 (when the Yukon grid does not typically have a fossil fuel generation requirement), and approximately 9 GW.h/month on average for the remaining six months (with lowest generation in April and May at about 7 GW.h/month). This represents a revised water management scheme for West Creek to maximize winter energy generation.
- Potential Summer Cruise Ship Load of 30 GW.h/Year
  - The potential cruise ship load to be supplied from the West Creek Hydro project is reviewed in section 1.1.2 of Background Paper #1 (Figures 6 and 7); this indicates that about one-third (11 GW.h for total season) of the cruise ship load involves ships that can

[13] However, input parameters such as Project costs and power production estimates have been updated as per the technical work completed as part of the current study.

currently connect to shore power (it is assumed that the balance could potentially be converted in 1-2 years under economic conditions).

  - A recent funding application estimated diesel generation cost per kW.h for cruise ships at about 33.4 cents/kW.h (2017), including about 32.1 cents/kW.h fuel costs and 1.3 cents/kW.h operating and maintenance expenses.

- Potential surplus power from West Creek Hydro project available to ship to Yukon to meet winter load requirements of 54 GW.h/Year
  - The most recent Yukon Energy ("YEC") updated near-term grid load scenario forecasts[14] indicate long-term average fossil fuel (diesel or LNG) generation requirement without any new industrial loads or new renewable generation ranging from 2018 to 2026 at 31.4 to 55.0 GW.h/yr (with growing requirements thereafter); these requirements would increase to the extent that DSM is less than assumed, and decrease to the extent that other renewable generation is developed for the Yukon grid.
  - YEC load forecast scenarios show that a potential new industrial load of 54 GW.h/yr in 2018 (Carmacks Copper) would increase fossil fuel generation requirements in the range of 37-40 GW.h/yr for about 7.5 years. It was noted that updated information indicates that this mine project is currently stalled (due to need to address regulatory review and related project design issues).

SCENARIO 2 – DEVELOPMENT WITH YEC SUMMER HYDRO SURPLUS & SKAGWAY CRUISE SHIP LOADS

This development scenario is focused on development of the transmission corridor in advance of any new hydropower developments in the Upper Lynn Canal area (such as West Creek hydro generation project) being developed. The transmission corridor would be developed to ship surplus summer power from Whitehorse to Skagway to displace summer cruise ship diesel generation loads as soon as shore power is available in Skagway.

Scenario 2 - Development with YEC Summer Hydro Surplus & Skagway Cruise Ship Loads

Whitehorse, Yukon	**Skagway, Alaska**
About 30 GW.h/yr from Yukon to Alaska →	
Surplus Hydro (early June through September) Assume up to about 34-38 GW.h surplus summer hydro with current generation & loads - need LNG backup	Energy for Cruise Ships (early May through September) About from 30 GW.h per season with peak load 6.5 to 32.5 MW in different weeks over the period
Financial & Economics viability issues (beyond timing): Charges for hydro power supplies Charges for LNG back up generation Factors that reduce hydro surplus Upper limit on viable transmission charges	Financial & Economics viability issues (beyond timing): Diesel cost saved by ships Shore power connection costs Factors that limit cruise ship diesel displacement volumes Competitive cost option (LNG generation at Skagway)

In summary:

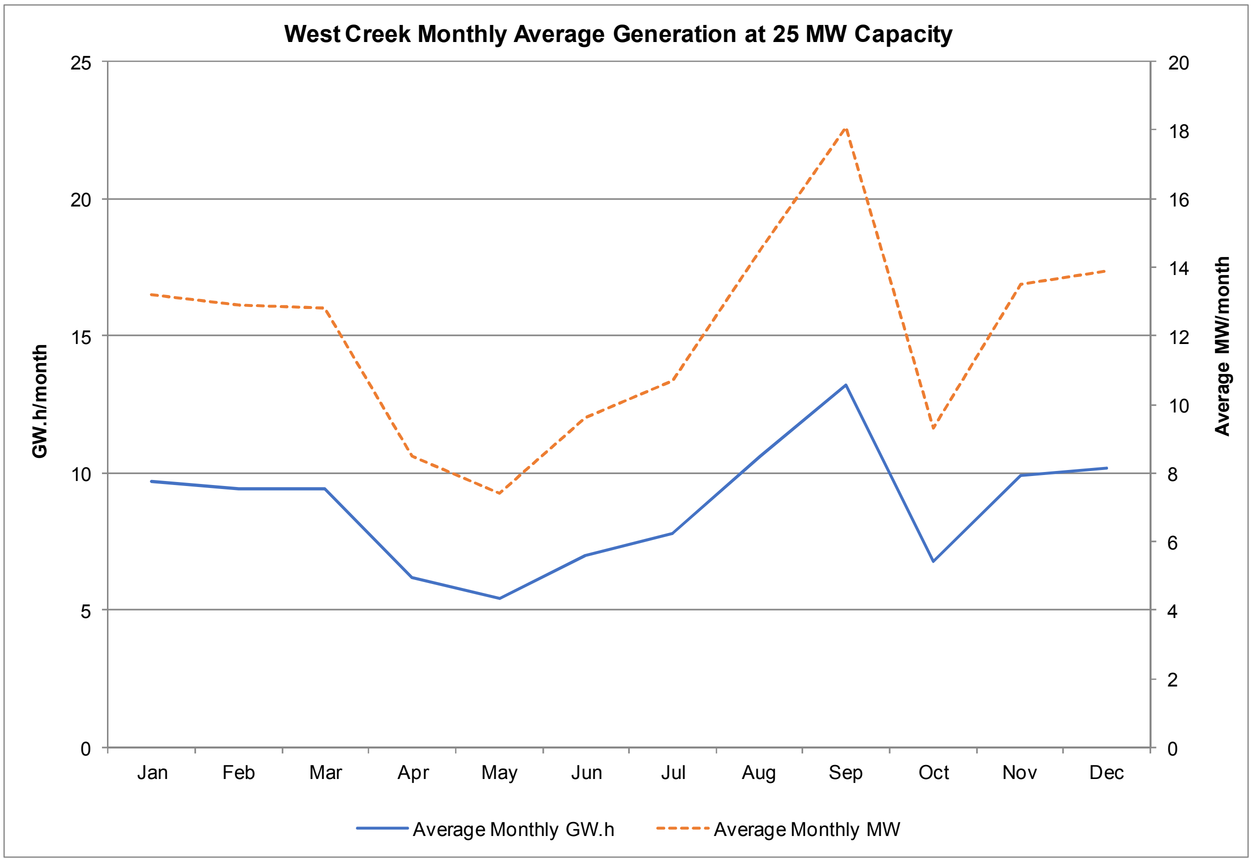
[14] Filed in December 2013 re: Application under Part 3 of PUA for Proposed Whitehorse Diesel-Natural Gas Conversion Project.

- Potential surplus generation of 34 to 38 GW.h/year is available in Yukon from early June to end of September.
    - Yukon Summer Surplus Hydro (Figure 2 in Background Paper #2) indicates that in 2018, summer surplus hydro without new mine connections ranges from 34 to 38 GW.h with average surplus per week ranging from 4 to 15 MW over the period; any new mine connections would reduce this surplus over the summer period.
    - Concerns were noted that capacity (MW) of surplus hydro range only from 4 to 15 MW to supply cruise ship capacity requirements of 25 MW or more, and that YEC LNG generation could be considered as backup subject to pricing arrangements.
    - It was noted that Scenario 2, with its lower transmission loads relative to Scenario 1, would not enable recovery of the full annual cost of the transmission line under normal financing arrangements, i.e., this scenario would require some level of government funding support (which will be assessed), and therefore the ultimate viability of the project would presume either a future Scenario 1 or some other future cost effective renewable supply would be developed to use the line to displace Yukon winter fossil fuel generation.

ATTACHMENT B – UPDATED WEST CREEK HYDRO GENERATION

The updated simulation for West Creek Hydro[15] in Figure B-1 below shows the annual long term average hydro generation capability for West Creek Hydro development at 106 GW.h for a 25 MW capacity plant, including simulated monthly generation capability, based on 15 years of water records (1963-1977)[16].

Figure B-1: West Creek Hydro Monthly Average Generation at 25 MW Capacity



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
GW.h	9.7	9.4	9.4	6.2	5.4	7.0	7.8	10.6	13.2	6.8	9.9	10.2	105.6
													Average
MW	13.2	12.9	12.8	8.5	7.4	9.6	10.7	14.5	18.1	9.3	13.5	13.9	12.0

As the table for Figure B-1 shows, updated long term average generation capability for West Creek Hydro approximates 55 GW.h on average from June 1 to November 30 (when the Yukon grid does not typically

[15] Based on "Review of West Creek Hydro Site – Viability Analysis of Southeast Alaska and Yukon Economic Development Corridor" December 4, 2014 Memorandum prepared by Access. This information was also provided in the Morrison Hershfield December 11, 2014 "Technical Feasibility Memorandum."
[16] Long-term average generation for 1963-1977 years. Figure 3 of the December 4, 2014 Memorandum prepared by Access Consulting shows that generation ranges between about 87 GW.h/year (water year 1973) and about 131 GW.h (water year 1977).

have a fossil fuel generation requirement), and approximately 8.4 GW.h/month on average for the remaining six months (with lowest generation in April and May at about 5.4 – 6.2 GW.h/month).

The West Creek Hydro power utilization estimates to displace thermal generation depend on a number of conditions for 2025 (i.e., the earliest potential date for West Creek Hydro in service) and beyond. These conditions cannot be predicted with any great confidence at this time. Some of these conditions include Yukon grid and Cruise ship load levels and thermal generation requirements, water availability in any specific year and whether or not all cruise ships are equipped with shore power connection (and whether related shore facilities for connection are also installed on shore).

For the purpose of assessing the financial feasibility of the Southeast Yukon-Alaska interconnection Project, the June workshop defined Development Scenario 1 assuming West Creek Hydro is developed. The following analysis updates the assumed thermal generation displacement under Scenario 1, focusing for convenience on such displacement in the initial years of the Project and of West Creek Hydro operation (e.g., 2025 to 2030). To the extent that the Project is financially feasible based on thermal displacement in these initial years, the situation will improve in subsequent years to the extent that Yukon grid loads and thermal displacement opportunities increase without any concurrent reductions in Cruise Ship loads.

Figure B-2 below updates the overlap of West Creek Hydro monthly generation (as updated) with YEC thermal generation requirements and load estimates for Cruise Ships as provided in the June 2014 Workshop. As reviewed in the June 2014 workshop, YEC's thermal generation forecasts as adopted for this study are based on Yukon grid load and thermal generation forecasts provided in the December 2013 Yukon Energy Application under Part 3 of Public Utilities Act for the Proposed Whitehorse Diesel-Natural Gas Conversion Project, assuming current renewable generation and licences on the Yukon grid, i.e., the thermal generation forecasts exclude development of any new renewable generation sources and/or changes to current licences[17].

Considering the Yukon grid load forecast with no mine connections in 2030 (when West Creek Hydro could potentially be in-service) Figure B-2 shows the following (assuming West Creek Hydro generation is allocated first to displace Cruise Ship thermal generation):

- West Creek Hydro can potentially displace about 47 GW.h of YEC long term average thermal generation requirement during winter months, based on 2030 forecast Yukon grid loads assuming no mine loads being connected to the grid[18] and an assumed 5% line losses on West Creek generation. Higher thermal displacement would be feasible to the extent that any mine loads were connected and/or non-mine load growth exceeded the assumed forecast (which would be forecast to occur for years subsequent to 2030).

[17] As noted at the June 2014 Workshop, development of smaller hydro enhancements on the Yukon grid may occur in near term that would reduce thermal generation requirements (i.e., if Mayo Lake and Marsh Lake enhancements are assumed to proceed, then diesel generation requirements would be reduced by 4 and 6 GW.h/year respectively). Gladstone is not expected to proceed in near term, but were it to proceed it would materially reduce the diesel generation requirements on the Yukon grid. Other new renewable projects may occur over the forecast period to 2030 - however, there are no specific plans at this time for specific new renewable projects to be developed.

[18] The Yukon grid load forecast for YEC was not extended beyond year 2030. In the table under Figure B-2, West Creek Hydro generation for the months of January through April is fully utilized to displace YEC's thermal generation at the assumed 2030 grid load with no mine connected loads, and the West Creek generation is fully used in May for Cruise Ships and some contribution to YEC generation. Figure B-2 indicates that August through October is the period when West Creek Hydro supply tends to be underutilized at currently forecast loads, i.e., with the 2030 forecast sales to Yukon and Cruise Ships, unused West Creek generation equals 29.9 GW.h with 26.9 GW.h occurring in August to December and 19.3 GW.h in August to October.

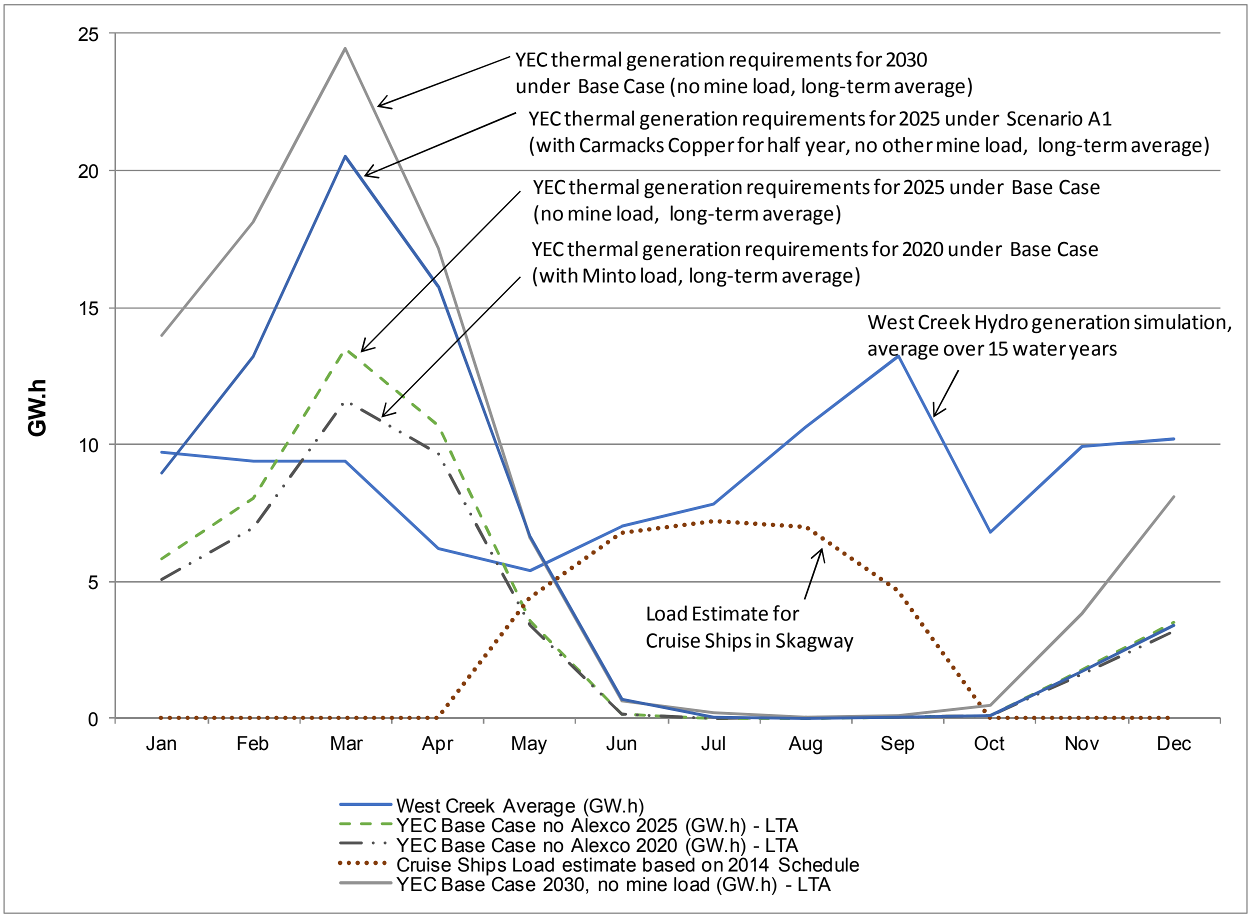
- At the same time, West Creek Hydro is shown to provide about 25 GW.h of energy required for Cruise Ships during summer months; to allow for capacity constraints, it is assumed that West Creek Hydro displaces only 75% of Cruise Ship thermal generation in June and July (and 80% in August) and that the balance of the forecast 30 GW.h/year diesel load is displaced by Yukon grid summer surplus hydro and/or backup YEC LNG generation[19].
- In sum, based on these load assumption, total sales of West Creek Hydro generation in 2030 would be about 72 GW.h/year [with about 5% losses this would require 76 GW.h West Creek Hydro generation which is 72% of full West Creek Hydro utilization at 106 GW.h].

Consequently, for the purpose of the Scenario 1 financial feasibility analysis for the interconnection Project, 72.0 GW.h/year of available energy from West Creek Hydro is estimated to be available to displace thermal generation requirements for YEC and for Cruise Ships.

It is noted that the Figure B-2 estimates of West Creek Hydro generation for Cruise Ship and/or Yukon grid loads are very preliminary. The estimates are developed without ability to simulate actual Yukon grid and/or West Creek Hydro system operation to evaluate likely long-term average ability to use hydro and/or LNG generation (and the required mix of these two generation sources) to displace the assumed Cruise Ship diesel generation requirements and/or Yukon grid thermal generation requirements.

[19] As noted in June 2014 Workshop, the Cruise Ship load demand can reach 25 MW when two or more large ships dock at the same time; in this situation West Creek Hydro would likely not be able to meet the total load requirements for Cruise Ships. Under these conditions, lower cost LNG generation from Yukon could be considered as backup generation, when required, subject to pricing arrangements and capacity. The table under Figure B-2 also notes forecast Yukon grid summer surplus hydro under various future load conditions and years – however, as noted in the June 2014 workshop papers (Background Paper #2, section 2.2), average MW Yukon grid surplus hydro capacity during summer months tends to emerge only during June (at a low level), increasing to only 9 to 15 MW in August, i.e., more analysis is needed to assess capability to use surplus hydro (e.g., through use of daily storage) to meet varying daily Cruise Ship peak MW requirements and the extent to which backup LNG generation would be required.

Figure B-2: West Creek Monthly Average Generation, YEC Thermal Generation Requirements and Cruise Ships Loads



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
West Creek Simulated Generation													
Average Annual over 15 Water Years	9.7	9.4	9.4	6.2	5.4	7.0	7.8	10.6	13.2	6.8	9.9	10.2	**105.6**
Cruise Ships	-	-	-	-	**4.4**	**6.8**	**7.2**	**7.0**	**4.6**	-	-	-	**29.9**
YEC Thermal Generation													
Base Case no Alexco 2020	5.1	6.9	11.6	9.6	3.4	0.1	0.0	0.0	0.1	0.1	1.6	3.2	**41.1**
Base Case no Alexco 2025	5.8	8.0	13.5	10.7	3.5	0.1	0.0	0.0	0.0	0.1	1.8	3.5	**46.8**
Scenario A1 2025	9.0	13.2	20.5	15.7	6.6	0.7	0.0	0.0	0.0	0.1	1.7	3.4	**71.0**
Base Case no mines 2030	14.0	18.1	24.5	17.1	6.6	0.6	0.2	0.1	0.1	0.5	3.8	8.1	**92.5**
West Creek Thermal Displacement*													
YEC Thermal Generation (2030)	9.2	9.0	9.0	5.9	0.8	0.6	0.2	0.1	0.1	0.5	3.8	8.1	**47.2**
Cruise Ships Thermal Generation	-	-	-	-	4.4	5.0	5.4	5.6	4.6	-	-	-	**25.0**
Total Thermal Displacement	9.2	9.0	9.0	5.9	5.1	5.6	5.6	5.6	4.7	0.5	3.8	8.1	**72.1**

* Assumes: line losses at 5% on West Creek sales; West Creek Hydro generation allocated first to displace Cruise Ship thermal generation; June-July sales at 75% [and August sales at 80%] of Cruise Ship load due to West Creek capacity constraints.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
YEC Surplus Hydro													
Base Case no Alexco 2020	-	-	-	-	0.4	5.9	7.8	9.0	9.0	2.5	-	-	**34.6**
Base Case no Alexco 2025	-	-	-	-	0.4	6.3	8.4	9.6	9.4	2.5	-	-	**36.6**
Scenario A1 2025	-	-	-	-	0.0	2.4	8.2	9.5	9.1	2.4	-	-	**31.6**
Base Case no mines 2030	-	-	-	-	0.0	2.6	5.2	6.2	5.6	1.4	-	-	**21.1**

ATTACHMENT C – WEST CREEK HYDRO COST ESTIMATES

Table C-1 provides a summary of the updated West Creek Hydro construction cost estimates based on the Memorandum prepared by Access Consulting[20]. As reviewed in the notes below, considerable uncertainty remains in these cost estimates.

Table C-1: West Creek Updated Construction Cost Estimates

	Item	Costs ($000 US 1983)	Inflated Costs ($000 US 2013)
1	Preparatory Work	5,600	13,100
2	Damand Reservoir	44,500	104,100
3	Power Conduit	11,900	27,800
4	Power Plant	12,000	28,800
5	Switchyard and Transmission Line	4,300	10,100
	Subtotal	78,200	183,200
	Contingencies (25%)	19,600	45,800
	Direct Construction Cost	97,800	229,000
	Engineering and Owner Administration (15%)	14,700	34,400
	Total Construction Cost	112,400	263,400

As shown in Table C-1, the updated cost estimate adjusted an earlier 1983 cost estimate (prepared for a 22.5 MW installed capacity) by inflating up to 2013$ value using the U.S. Annual Consumer Price Index (134% increase in costs from 1983 to 2013). These estimates do not include socio-environmental assessment, permitting and mitigation related costs which are estimated at about $13 million (US 2013$).

Based on these cost updates it is estimated that the total cost for West Creek Hydro would be about $327 million (CAD, 2014$) as per Table C-2 below.

Table C-2: West Creek Updated Cost Estimates

West Creek Hydro	**US** $000 US	**CAD** $000 CAD
Total Construction Cost (2013$)	263,400	305,544
Socio-Environmental Assessment, Permitting and Mitigation (2013$)	13,000	15,080
Total Cost (2013$)	**276,400**	**320,624**
Total Cost (2014$, assumed 2% inflation)	**281,928**	**327,036**

[20] "Review of West Creek Hydro Site – Viability Analysis of Southeast Alaska and Yukon Economic Development Corridor" December 4, 2014 Memorandum prepared by Access Consulting.

Notes to Table C-1 and Table C-2:

1. Construction costs are high level estimates and are based on 1983 cost estimates for a 22.5 MW plant capacity [1982-83 study by R.W. Beck] and inflated to a 2013$ value using the U.S. Annual Consumer Price Index (cost estimate prepared by Access Consulting). An inflation factor of 134% was used to inflate costs from 1983 to 2013 (30 years), based on US CPI for this period. Access Consulting also notes that it is reasonable to expect project costs to range anywhere between $200M US to $350M US depending on the selected installed capacity and the final layout that is selected.

2. Access Consulting notes that in the 1983 cost estimates the power conduit and power plant items appear to be low, and if the selected option is to build a power tunnel (instead of a penstock), construction costs may increase as much as by $27.8 million (US).

3. Access Consulting also notes that if the installed capacity was optimized to match the available inflows in the watershed, as discussed previously (in a 15 to 18 MW range), project costs could be reduced by approximately 10% compared to the proposed 25 MW installed capacity.

4. Canadian dollar at $1 US = $1.16 CAD based on exchange rate as of January 2, 2015 (Bank of Canada).

5. Scaling up the 1983 R.W. Beck study with US GDP deflator (rather than CPI) yields a total capital cost for the West Creek Hydro (2014$) of $240.546 million (US$) or $279.033 million (CAD$).[21] These estimates are approximately 85% of the estimates provided in Tables C-1 and C-2.

6. The Southeast Alaska Integrated Resource Plan (Table 10-4) shows the estimated capital cost for 25 MW West Creek Hydro between $112 million and $168 million (US, 2011$).

7. The June 2014 Workshop noted that the cost estimate for West Creek Hydro was at $140 million based on West Creek economic analysis provided as part of Renewable Energy Fund Round 6 Grant Application of the Municipality of Skagway in 2012 before Alaska Energy Authority[22].

8. The 2014 AP&T FERC Application assumed a different project concept than the 1982-1983 Beck study (see Access Consulting memorandum). Based on discussions with AP&T, it is understood that the $140 million (US$ 2011) estimated for a 25 MW project basically assumed a run-of-river

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[21] The US CPI inflation used by Access Consulting is 134% for this period. The Steering Committee suggested use of the US GDP deflator for this same period, which shows 102% inflation or an average of about 2.30%/year over 31 years (source US Dollar Implicit Price Deflator for Gross Domestic Product, 1929-2014, 2009=100, Bureau of Economic Analysis, US Government available at http://www.bea.gov/national/index.htm#gdp [accessed on March 9, 2015]). Use of the GDP deflator yields total construction cost of $227.546 million (US$2014), and total cost (US$2014) of $240.546 million or $279.033 million (CAD$2014).

[22] Grant Application by Municipality of Skagway is available though Alaska Industrial Development and Export Authority ftp site at ftp://www.aidea.org/REFund/Round%206/Applications/918_West%20Creek%20Hydroelectric%20Project/ [accessed on March 9, 2015].

type project that would supply primarily summer energy for the cruise ships and that the preliminary capital cost estimate essentially cut the dam cost in half from the earlier Beck costs.[23]

As reviewed in Attachment E, LCOE estimates for West Creek Hydro were developed for the interconnection Project feasibility analysis based on the $327 million CAD$2014 capital cost estimate, assumed annual O&M costs [CAD$2014] at 0.5% of the capital cost estimate, and an economic life of 90 years.

[23] Table C-1 shows 1983 "Dam and Reservoir" cost (US$1983) at $44.5 million of $78.2 million subtotal before contingency, or in effect accounting for 56.9% ($63.9 million) of the $112.4 million total construction costs (US$1983).

ATTACHMENT D – SKAGWAY – WHITEHORSE TRANSMISSION LINE COSTS

Table D-1 provides a summary of the interconnection Project transmission line costs as estimated by Morrison Hershfield[24].

Table D-1: Skagway – Whitehorse Transmission Line Costs (CAD, 2014$)

		Option A New ROW along Highway		Option B ATCO ROW		Option C New ROW along railway	
		No Fibre $000 CAD	**With Fibre** $000 CAD	**No Fibre** $000 CAD	**With Fibre** $000 CAD	**No Fibre** $000 CAD	**With Fibre** $000 CAD
Transmission Line							
Total	170 km (105.6 miles)						
Alaskan portion	19 km (11.8 miles)						
Canadian portion	151 km (93.8 miles)						
Alaskan portion		32,453	34,055	32,453	34,055	32,453	34,055
Transmission Line		*14,420*	*16,021*	*14,420*	*16,021*	*14,420*	*16,021*
Substation		*18,033*	*18,033*	*18,033*	*18,033*	*18,033*	*18,033*
Canadian portion		76,160	93,587	90,405	111,750	85,478	104,060
Transmission Line		*74,188*	*91,616*	*88,434*	*109,779*	*83,507*	*102,089*
Substation Upgrade		*1,971*	*1,971*	*1,971*	*1,971*	*1,971*	*1,971*
Total Transmission Line		**108,612**	**127,642**	**122,858**	**145,805**	**117,931**	**138,115**

Note to the table:

1. Alaskan portion of the transmission line costs have been converted to Canadian dollar at $1 US = $1.16 CAD based on exchange rate as of January 2, 2015 [Bank of Canada].

As noted in Table D-1, transmission line costs are estimated to be between $108.6 million and $145.8 million (CAD, 2014$) depending on the Right of Way (ROW) option selected and on whether fibre options are included or excluded.

The average cost per km of the transmission line is estimated to be higher on the Alaskan side (as shown in Table D-2). Part of the higher costs is due to the exchange rate which is based on Bank of Canada exchange rate on January 2, 2015 at $1.16 CAD = $1 US. For example, for Option B the cost for the Alaskan side in US$ would be $0.654 million/km for no fibre option (compared to $0.586 million/km for Canadian side), and $0.727 million/km for with fibre option (compared to $0.727 million/km for Canadian side)[25].

[24] The cost estimates provided by Morrison Hershfield (January 2, 2015) for Canadian side was presented in Canadian dollars and Alaskan side in US dollars. Alaskan portion of the transmission line costs have been converted to Canadian dollar at $1 US = $1.16 CAD based on exchange rate as of January 2, 2015.

[25] By way of example, Southeast Alaska Integrated Resource Plan (SEIRP) provides analysis with relation to the potential transmission connection between southeast Alaska communities, including connection of Haines to Juneau and it notes that the project total cost would be about $244 million (2011$ US, SEIRP, page 12-36, Table 12-8) for 85.3 miles (the cost estimated to be

Table D-2: Skagway – Whitehorse Transmission Line Costs (CAD, 2014$)

		Option A New ROW along Highway		Option B ATCO ROW		Option C New ROW along railway	
		No Fibre $000 CAD	**With Fibre** $000 CAD	**No Fibre** $000 CAD	**With Fibre** $000 CAD	**No Fibre** $000 CAD	**With Fibre** $000 CAD
Without substation cost							
Alaskan portion		14,420	16,021	14,420	16,021	14,420	16,021
Canadian portion		74,188	91,616	88,434	109,779	83,507	102,089
Alaskan portion	km	19	19	19	19	19	19
Canadian portion	km	151	151	151	151	151	151
Alaskan portion	$000/km	759	843	759	843	759	843
Canadian portion	$000/km	491	607	586	727	553	676

Note: Alaskan portion is about 12 miles, Yukon portion is about 94 miles.

As provided in Tables D-1 and D-2 above, the fibre options add about $19-$23 million to the cost of transmission line. Based on information available from the Government of Yukon,[26] the cost of installation of fibre between Skagway and Whitehorse (as currently planned without use of the transmission line) is estimated to be in the range of $9.5 million, which is much lower compared to fibre options added cost to the transmission lines noted in the above tables. Accordingly, the financial feasibility analysis of the interconnection Project does not consider further the fibre option.

Taking into account the above cost options, the lowest cost option (Option A) without fibre option is assumed for the financial feasibility analysis to be the most economically feasible option compared to the other options provided in Table D-1. Accordingly, the Project capital cost of $108.6 million for Option A (no fibre) is used for the Base Case feasibility analysis. In contrast, the most costly Project option without fibre (Option B) is approximately 13% higher than Option A.

As reviewed in Attachment E, annual O&M costs for the interconnection Project are estimated at $1,608/km or $273,300 per year (CAD, 2014$).

about $2.8 million/mile) of 69 kV transmission line (about 137 km). Table 12-1 of SEIRP provides generic costs of transmission line which estimated to be about $0.446 million/mile when use wood poles and $0.481 million/mile when use steel poles.

[26] Information from Department of Economic Development Government of Yukon.

ATTACHMENT E – PROJECT FINANCIAL FEASIBILITY ANALYSIS: ASSUMPTIONS

In order to prepare the Base Case financial feasibility analysis for the Project the following assumptions are used:

1. **Capital Costs:**
   a. **Interconnection Project** capital costs for base case scenario at $108.6 million (2014$ CAD) (as per Table D1 of Attachment D, assuming Option A with no fibre option).
   b. **West Creek Hydro** capital cost at $327 million (2014$ CAD) (as per Table C-2 of Attachment C).
2. **Annual Operating and Maintenance (O&M) costs:**
   - **Interconnection Project annual O&M costs** assumed at $1,608/km or $273,300 per year (CAD, 2014$); includes $1,407.6/km [2014$] brushing/cleaning for Canadian portion [151 km or 94 miles] based on YEC average cost for transmission lines[27], $2,051/km O&M [CAD, 2014$] for all of the 19 km [11.8 miles] US portion, and $3,107/km added brushing/cleaning [CAD, 2014$] for the first 7 km [4.3 miles] only of the Alaskan portion of transmission line (based on Southeast Alaska Power Agency experience).
   - **West Creek Hydro annual O&M costs** assumed at 0.5% of total cost consistent with YEC Resource Plan analysis[28]. The O&M cost would be about $2.0 million for 2025. This is comparable to the O&M expenses used in West Creek economic analysis (Skagway Round 6 Grant Application before Alaska Energy Authority, 2012) which assumed $2.3 million for 2025.
3. **West Creek Hydro generation sales** for Scenario 1 development estimated at 72 GW.h/year (about 76 GW.h/year generation including line losses). As reviewed in Attachment B, this includes about 47 GW.h YEC thermal generation displacements in 2030 and about 25 GW.h diesel generation displacement for Cruise Ships[29].
4. **Project Economic Life** - It is assumed that the project economic life for the interconnection Project is 55 years and for West Creek Hydro is 90 years, based on experience with the most recent developments for YEC [Mayo B Hydro assets amortize over about 90 years and CSTP 138 kV transmission line over 55 years].
5. **Development Timeline** - It is assumed that it would take a minimum 10 years to develop West Creek Hydro with potential in-service date of 2025 for Scenario 1 and for Scenario 2 it is assumed

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[27] YEC's 2012/13 GRA, response to CW-YEC-1-18 which shows $1,380/km.
[28] YEC 20-Year Resource Plan: 2011-2030.
[29] As reviewed in Annex B, the thermal generation displacement will depend on load levels, new renewable projects in Yukon (Mayo Lake, Marsh Lake, etc.) and other conditions. With about 5% line losses (i.e. 72 GW.h load at sales level and plus 5% for line losses) would result in about 76 GW.h West Creek generation which is 72% of long-term average simulated generation capability of 106 GW.h/year.

that the interconnection Project can be in-service at the earliest in 2020 (assumes about five years for permitting and building)[30].

6. **Cost of Capital** at 5.45%/year with inflation (nominal discount rate) and 3.38%/year excluding inflation (real discount rate). The 5.45%/year nominal discount rate is consistent with YEC's latest average cost of capital used for the LNG Part 3 application analysis (assumes 60% debt at 3.6% average debt cost and 40% equity at 8.25% return) and comparable to the financial cost used in West Creek economic analysis (Skagway Round 6 Grant Application before Alaska Energy Authority, 2012) which assumed at 6%). The real discount rate of 3.38%/year assumes inflation at 2%/year.

7. **Annual inflation rate** assumed at 2% [based on data from Department of Labor and Workforce Development the annual change in CPI for Anchorage for the last five years (2009-2013) averages to 2.3%; based on data from Yukon Bureau of Statistics the annual change in CPI for Whitehorse for the same period averages to 1.6%].

8. **Interconnection Project Line Use** assumed as follows (for the base case a simple constant level of annual line use is assumed for each scenario over the 55 year economic life of the Project):

    a. **Scenario 1**: as reviewed in Attachment B, starting in 2025 to 2030 time frame, 47 GW.h/year sales in Whitehorse during winter months (as reviewed in Attachment B) from 49 GW.h/year generation at West Creek Hydropower (assumes 5% incremental line loss); 5 GW.h/year sales in Skagway during summer months from 5.5 GW.h/year of surplus hydro and/or LNG power generated on the Yukon grid (assumes 10% line loss).

    b. **Scenario 2**: assuming Cruise Ship load of 30 GW.h/year is available and connected to be displaced, starting in 2020 time frame, 30 GW.h/year sales in Skagway during summer months from 33 GW.h/year of surplus hydro and/or LNG power generated on the Yukon grid (assumes 10% line loss).

9. **Sales rates for power purchases** assumed as follows (CAD, 2014$) based on June 2014 Workshop information and assumptions:

    a. **Alaska Cruise Ship summer power purchases**: assumed purchase power rate at $0.27/kW.h (net of any land distribution cost charges) for power supplied to cruise ships by YEC or West Creek Hydro (assumed at about 87% of ship diesel fuel and O&M cost estimates provided at the June Workshop, ignoring conversion from US to CA dollars).[31]

    b. **YEC Yukon grid winter power purchases**: assumed power purchase rate in the 2025 time period at $0.165/kW.h to displace thermal power generation (proxy for LNG thermal

[30] As noted in June 2014 Workshop, the transmission project could require from 5.5 to 7.5 years to develop, including feasibility assessments (up to 18 months), permitting and licensing (up to 24 months), and procurement and construction period (up to 36 months). Staged decision-making with could facilitate development at the earliest in about 5 years.

[31] Background Paper #1, page 1-6: analysis by Municipality of Skagway (Round 6 Grant Application before Alaska Energy Authority, 2012) estimated the Cruise Ship diesel fuel and O&M cost at 33.4 cents/kW.h (US$) for 2016 (32.1 cents/kW.h fuel and 1.3 cents/kW.h O&M). This appears to reflect an estimate of about 31 c/kW.h (US$) in 2014$.

fuel and O&M costs [CAD, 2014$], taking into consideration expectation that natural gas prices escalate notably over that time period faster than general inflation)[32].

c. **YEC sales of summer power to Cruise Ships**: assumed average power purchase rate, excluding interconnection Project charges, as follows:

   i. $0.13/kW.h for Scenario 1 YEC sales to Cruise Ships[33]; and

   ii. $0.09/kW.h for Scenario 2 YEC sales to Cruise Ships, assuming no new mine loads on the Yukon grid.[34]

10. PV Annual Costs (CAD, 2014$): based on the above assumptions, the PV annual costs for the Project and West Creek Hydro are assumed as follows:

a. **Interconnection Project:** $115.385 million total PV costs, including $108.612 million for capital development costs and $6.783 million PV costs for O&M over the 55 year economic life (discounted at the real discount rate of 3.38%/yr). Annual PV costs of $4.649 million assume constant annual real costs [in CAD, 2014$] over the economic life.

b. **West Creek Hydro:** $372.959 million total PV costs, including $327.036 million for capital development costs and $45.923 million PV costs for O&M over the 90 year economic life (discounted at the real discount rate of 3.38%/yr). Annual PV costs of $13.280 million assume constant annual real costs [in CAD, 2014$] over the economic life.

Financial Feasibility Analysis Approach

The financial feasibility analysis for each Development Scenario and sensitivity assesses the potential recovery of Project costs through charges for electricity transmitted over the interconnection.

Assumed Project charge rates in this analysis are based on assumed market constraints as well as estimated Project costs as reviewed below. In each case, constant dollar annual government funding support required over the economic life is estimated if assumed charge rates are not expected to recover estimated Project costs.

The analysis assumes, for simplicity, constant annual costs and revenues (over the assumed economic lives) to reflect the preliminary nature of any assessment based on current information regarding the

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[32] YEC Part 3 LNG Application and related update evidence (Ex. B-13) during the YUB hearing indicated a 2015 estimated cost for LNG delivered to Whitehorse from Delta BC (Vancouver) at 14.0 c/kW.h assuming A-train haul units and AECO gas price at $4.5/MMBtu; assuming YEC gas-fired generation O&M cost at 1.5 c/kW.h, the 2015 incremental fuel and O&M cost estimate is 15.5 c/kW.h, with natural gas fuel cost representing 4.09 c/kW.h of this total. A 16.5 c/kW.h incremental fuel and O&M cost [2014$] in 2015 assumes an AECO natural gas fuel price (in 2014$) of about $5.85/MMBtu, i.e., gas price escalation (from the price assumed for 2015) in real terms of about 30% over the time period to 2025. By way of reference, the NEB November 2013 Benchmark Price forecast for Henry Hub gas price assumed real escalation of 32% for this price from 2015 to 2025.

[33] Allows for about 60% of the sales using LNG generation for backup at the 16.5c/kW.h assumed fuel and O&M cost in 2015, and the balance at an assumed charge of 5c/kW.h for surplus hydro, plus 10% line losses on all sales.

[34] Allows for $0.08/kW.h from 2020 until after 2025 (and $0.106/kW.h by 2030) assuming about 20% of the sales using LNG generation for backup at the 16.5c/kW.h assumed fuel and O&M cost in 2015 (40% by 2030), and the balance at an assumed charge of 5c/kW.h for surplus hydro, plus 10% line losses on all sales.

interconnection Project and potential forecasts that affect Project feasibility.[35] The following are key elements in the financial feasibility analysis of the two development scenarios:

- **Present value (PV) costs for the Project and West Creek Hydro stated as fixed annual costs**: As reviewed in Attachment E, PV costs for the Project and West Creek Hydro are each stated in CAD, 2014$, including the assumed capital development cost and the assumed O&M costs over the relevant economic life (55 years for the Project and 90 years for West Creek Hydro).[36] Annual PV costs are assumed constant [in CAD, 2014$] over the respective economic lives (for the Base Case assumptions, at $4.649 million/year for the Project and $13.280 million/year for West Creek Hydro). This approach ignores normal utility rate recovery for such a Project which requires higher annual costs at the outset that decline over the economic life.
- **Assumed constant annual generation, loads and sales rates**: For simplicity, financial feasibility is assessed based on assumed constant annual generation, loads and sales rates (in real CAD, 2014$). This approach removes the complexities of varying annual forecasts over the respective economic lives of the Project and West Creek Hydro, and assumes that the analysis is conservative to the extent that Project use tends to improve over the economic life due to Yukon grid load growth. If the Project proceeds, further feasibility analysis will be needed to confirm that assumed conditions over the economic life will continue to sustain Project feasibility.
- **Lifecycle Cost of Energy (LCOE) in $/kW.h:** LCOE costs for the Project or West Creek Hydro reflect the respective PV annual costs divided by the relevant assumed constant annual Project load (i.e., electricity sales transmitted over the interconnection) or West Creek Hydro generation sales used to displace thermal generation in Alaska and Yukon.
    - **Scenario 1:**
        - **Project LCOE**: $0.089/kW.h [CAD, 2014$], assuming 52 GW.h/year sales transmitted (47 GW.h/year sales to Yukon from West Creek Hydro and 5 GW.h/year sales to Cruise Ships from Yukon).
        - **West Creek Hydro LCOE**: $0.184/kW.h [CAD, 2014$], assuming 72 GW.h/year sales from West Creek Hydro (47.0 GW.h to Yukon during winter, and 25.0 GW.h to Cruise Ships during summer).
    - **Scenario 2**:
        - **Project LCOE**: $0.155/kW.h [CAD, 2014$], assuming 30.0 GW.h/year sales transmitted during summer from Yukon to Cruise Ships.

[35] For example, forecasts for future Project and West Creek Hydro costs, Yukon and Cruise Ship loads, thermal generation available to be displaced by the Project, and relevant charge rates for power supplies that may affect Project viability.

[36] Under Base Case assumptions per Annex E, the overall PV costs [CAD, 2014$] over the economic life are $115.4 million for the Project and $373.0 million for West Creek Hydro.