YUKON ENERGY
CORPORATION
P.O. Box 5920
WHITEHORSE
YUKON Y1A 6S7
(867) 393-5300

July 3, 2018

Robert Laking, Chair
Yukon Utilities Board
Box 31728
Whitehorse, YT Y1A 6L3

Dear Mr. Laking:

Re: Yukon Energy Corporation 2017/18 General Rate Application – Undertakings

The oral hearing for the above matter concluded on June 28, 2018. Prior to the end of the oral hearing phase, Yukon Energy agreed to provide a number of undertakings to intervenors and to Board counsel.

Two specific undertakings to John Maissan were agreed to be provided by July 3, 2018 and are attached to this correspondence.

A number of other undertakings remain outstanding at this time, including undertakings to provide further information to Board counsel regarding updates related to 2017 and 2018 actual results. At this time, staff required to undertake this work (and in particular the updates needed for 2017 and 2018 actual results) are not available during this week due to planned vacation time. As such, Yukon Energy is seeking additional time to complete these undertakings.

On initial review of the transcript there appear to be 41 undertakings in total, with 13 answered on the record of the proceeding, and two additional undertakings provided with this July 3, 2018 correspondence (please see attached draft List of Undertakings). Yukon Energy will endeavor to provide outstanding undertakings as soon as they are completed and will provide all outstanding undertakings no later than July 13, 2018.

The current schedule in Board Order 2018-03 directs written Argument by July 12, 2018 and written Reply Argument by July 26, 2018. Given the above, it is suggested that the dates for Argument and Reply be adjusted to fall two weeks later than the current schedule.

If you have any questions, please contact the undersigned.

Yours truly,

Ed Mollard
Chief Financial Officer

Attachments

Undertaking # 12 and #13 at Page 264-67, line 1-4

At pages 264-67 an undertaking was made to provide an update to Figure 1 from JM-YEC-1-27 or a revision of Figure 1 from JM-YEC-1-27.

Yukon Energy Response:

This undertaking provides updated analysis for Figures 1 and 2 in John Maissan-YEC-1-27 (i), as requested by John Maissan during the oral hearing [June 27, 2018, Volume 2, transcript pages 264-267].

The original IR asked for a reproduction of a figure and table from page 10 of YEC's LNG Application with costs using actual energy load and actual fuel prices for the same years, and also both with and without YDC's $18.3 million contribution to the capital cost, The undertaking included two elements: (a) to reproduce Figure 1 in the response to include the YDC contribution for both LNG and diesel options, and (b) to reproduce Figure 2 (with extended years as appropriate) to include the third LNG engine in the analysis without any YDC contribution.

The undertaking response updates both Figures 1 and 2 of the earlier IR response for inclusion of the third LNG engine as at January 1, 2019, and an assessment of full 2019 year operations. Commentary is provided, based on this updated information, on the LNG project's ability to recover its added capital cost over the diesel option over the assumed 40 year economic life of the project.

Figures and related tables are reproduced using the following updated information:

1. **Capital costs**: assumed 40-year depreciation for costs other than decommissioning; return on mid-year rate base at 5.45% prior to 2017, and at 5.00% for 2017 and 2018[1]. The following capital costs and timing have been assumed for the LNG Project and the New Diesel Alternative:
    a. LNG Project
        i. Initial 2 units, in-service July 1, 2015:

[1] The 5.45% return was based on prior GRA and the 2013 Part 3 LNG Application, assuming the 8.25% return on equity approved in the last GRA (40% of capital structure) and 3.6% cost of new debt as then forecast (60% of capital structure). The 5.00% return for 2017 and 2018 reflects the current GRA proposed 8.75% return on equity (40% of capital structure) and an assumed 2.5% cost for new debt (Schedule 11 at page 7-15 shows interest on new debt below this level since 2014).

1. Total before YDC contribution: $41.933 million
2. Net after YDC contribution: $23.633 million

ii. Third LNG Engine (assumed in-service Jan 1, 2019): $8.9 million[2]

b. New Diesel Alternative (costs of $32.7 million and timing in 2014 and 2015 retained as per Part 3 Application Update); $14.4 million when assumed net of YDC contribution of $18.3 million.

2. **Delivered fuel costs**: actual diesel and LNG fuel costs for 2015-2017, actual fuel prices for Jan-April 2018:
   a. 2015:
      i. Diesel at 20.3 c/kW.h for new diesel and 23.7 c/kW.h for existing diesel.
      ii. LNG at 18.83 c/kW.h per DCF filing.

   b. 2016:
      i. Diesel at 18.6 c/kW.h for new diesel and 21.8 c/kW.h for existing diesel at Whitehorse.
      ii. LNG at 18.17 c/kW.h per DCF filing.

   c. 2017: reflects actual average 2017 delivered fuel prices ($0.9184/litre for diesel at Whitehorse, $0.4819/litre for LNG):
      i. Diesel at 21.46 c/kW.h for new diesel (4.28 kWh/litre) and 25.51 c/kW.h for existing diesel (3.60 kW.h/litre) at Whitehorse.
      ii. LNG at 18.75 c/kW.h @ 2.57 kWh/litre.

   d. 2018: reflects actual average delivered fuel prices for Jan-April 2018 ($1.0278/litre for diesel at Whitehorse, $0.4492/litre for LNG):
      i. Diesel at 24.01 c/kW.h for new diesel (4.28 kWh/litre) and 28.55 c/kW.h for existing diesel (3.60 kW.h/litre) at Whitehorse.
      ii. LNG at 17.48 c/kW.h @ 2.57 kWh/litre.

   e. 2019 assumes same fuel prices as for 2018 (i.e., ignores expected improvements in LNG delivered price with new Ferus facility).

[2] GRA cost estimate (page 5-26) of $6.2 million; this has been adjusted to $8.9 million; see YUB-YEC-1-71.

3. **LTA Thermal Generation**: Actual LTA thermal as per DCF filing for 2015-2017 (10.0 GW.h for 2015, 10.5 GW.h for 2016, 27.1 GW.h for 2017). The 2017 actual is assumed for 2018, and a higher LTA thermal of 41.7 GW.h for 2019 (assumes grid load of 468 GW.h with connection of VGC load in fall).

4. **Percent of LTA Thermal**: Based on GRA and noted constraints on use of larger units for small and short duration loads, assume 90% LTA thermal supplied by LNG (15% for 2015 due to in-service only after mid-year); for new diesel alternative, assume 50% of LTA thermal supplied by these units (based on similar constraints on use of larger units for small and short duration loads plus assumed low incentive to use for enhanced hydro storage during drought).

Figure 1A and related table below shows update of the original Figure 1, assuming YDC's $18.3 million contribution towards the LNG plant capital costs (and no similar contribution for the diesel option) with the updated information for 2017-2019 (including the third LNG engine).

Figure 1B and related table below shows the same information as Figure 1A except that YDC's $18.3 million contribution is assumed applied towards both LNG and New Diesel alternative option capital costs (as requested in the undertaking).

Updated Figure 2 and related table below shows the same information as Figure 1A except that no YDC contribution is assumed for either LNG or New Diesel option capital costs (as requested in the undertaking).

The figures and tables look only at the period through 2019. Given the connection of the VGC load in 2019, expected LNG benefits after 2019 for at least ten years are expected to exceed the estimates shown here for 2019.[3]

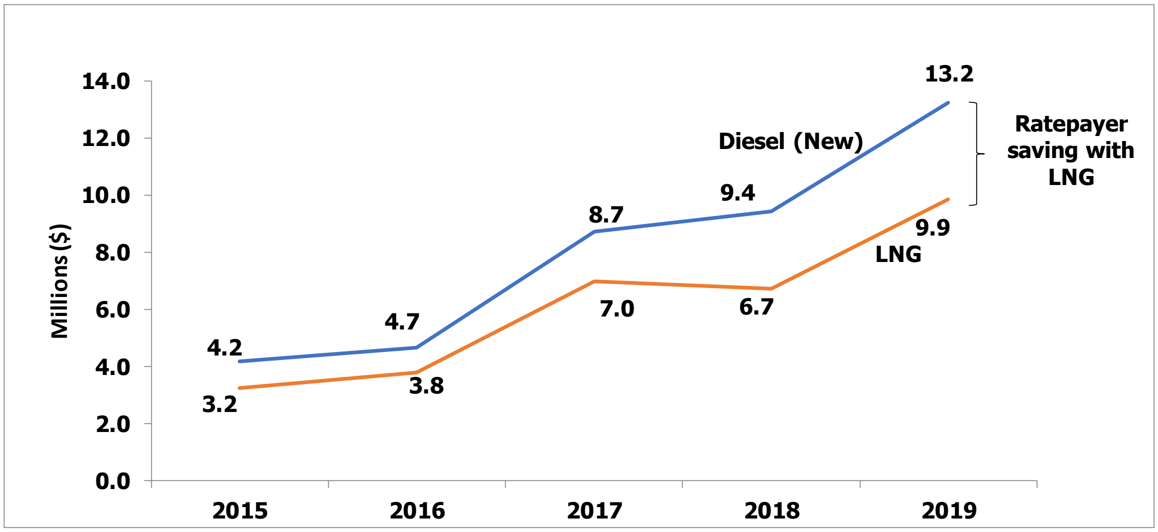
Looking at overall financial feasibility over the 40-year life of the LNG assets, the following are noted:

1. Figure 1A shows that, with the YDC contribution, the added capital cost for LNG of approximately $0.4 million compared to New Diesel is fully recovered by 2017.

[3] See response in VGC PPA hearing to YUB-YEC-1-28, Attachment 1 for LTA forecasts in 2020 (79.1 GW.h), 2021 (88.9 GW.h) and 2025 (66.5 GW.h) with the Eagle Gold mine load.

2. Figures 1B and 2 are similar, removing the LNG advantage related to the YDC capital contribution and leaving an added capex with LNG compared to New Diesel of $18.7 million. Approximately $3.6 million of this added cost is recovered by the end of 2019 in the attached tables – and based only on the $2.1 million net saving in the last year shown (2019), the balance of the added capex with LNG will be recovered within the next 7.2 years, i.e., within the expected life of the VGC mine, and well with the 40 year expected life of the LNG assets.

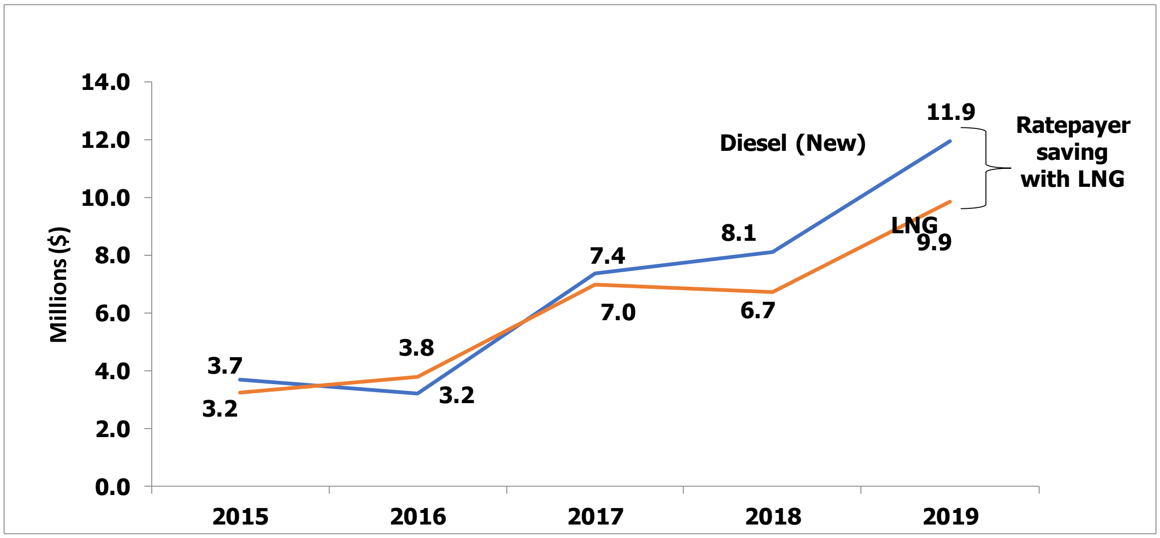
Figure 1A: Updated: Annual Ratepayer Costs - LNG vs New Diesel: 2015-2019 (LNG Capital Cost after $18.3 million contributions)



Annual Ratepayer Cost for Capital & Fuel ($million per year)

	2015	2016	2017	2018	2019
Diesel (New)	4.2	4.7	8.7	9.4	13.2
Gas/LNG	3.2	3.8	7.0	6.7	9.9
Saving (Diesel-LNG)	**1.0**	**0.9**	**1.7**	**2.7**	**3.4**

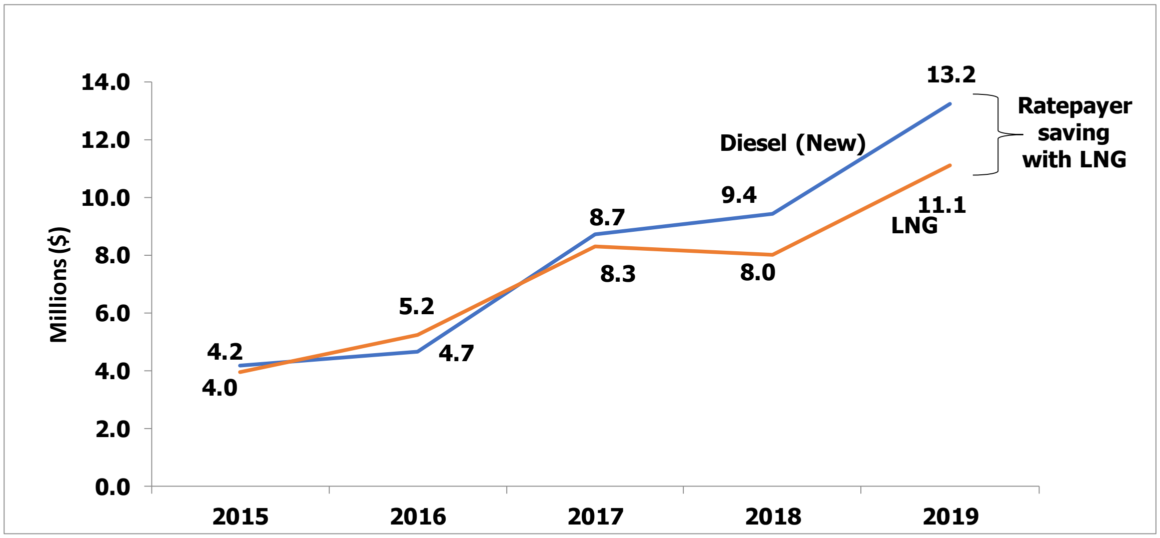
Figure 1B: Updated: Annual Ratepayer Costs - LNG vs New Diesel: 2015-2019 (both LNG and diesel capital costs assume $18.3 million contributions)



Annual Ratepayer Cost for Capital & Fuel ($million per year)

	2015	2016	2017	2018	2019
Diesel (New)	3.7	3.2	7.4	8.1	11.9
Gas/LNG	3.2	3.8	7.0	6.7	9.9
Saving (Diesel-LNG)	**0.5**	**-0.6**	**0.4**	**1.4**	**2.1**

Figure 2: Updated: Annual Ratepayer Costs – LNG vs New Diesel: 2018-2019 (LNG Capital Cost at $51.4 million – No YDC Capital Contributions)



Annual Ratepayer Cost for Capital & Fuel ($million per year)

	2015	2016	2017	2018	2019
Diesel (New)	4.2	4.7	8.7	9.4	13.2
Gas/LNG	4.0	5.2	8.3	8.0	11.1
Saving (Diesel-LNG)	**0.2**	**-0.6**	**0.4**	**1.4**	**2.1**

Table 1A: Updated Table 4-3 Ratepayer Impacts from Whitehorse Diesel-Natural Gas Conversion Project - ($million) (Project compared to New Diesel Alternative) LNG Capital Costs after YDC Contribution of $18.3 million

		2014	2015	2016	2017	2018	2019
Capital cost ($million) at yr end							
Total	Diesel (new)	21.60	11.10				
	LNG		23.63				8.9
Net	Diesel (new)	21.60	32.2	31.4	30.6	29.8	29.0
	LNG	0.00	23.3	22.7	22.2	21.6	29.7
Difference (LNG-Diesel)							
Annual Capital Cost ($million)							
Deprec	Diesel (new)		0.516	0.794	0.794	0.794	0.794
	LNG		0.295	0.591	0.591	0.591	0.813
Return	Diesel (new)		1.466	1.732	1.550	1.510	1.470
	LNG		0.636	1.256	1.123	1.093	1.280
Total	Diesel (new)		1.982	2.526	2.343	2.304	2.264
	LNG		0.931	1.847	1.713	1.684	2.094
Difference (LNG-Diesel)			**-1.050**	**-0.680**	**-0.630**	**-0.620**	**-0.170**
Annual Fuel Cost ($million)							
Forecast LTA Diesel (GWh)			10.0	10.5	27.1	27.1	41.7
% New	Diesel (new)		50%	50%	50%	50%	50%
	LNG		15.0%	90%	90%	90%	90%
Fuel Cost	Diesel (new)		2.202	2.128	6.370	7.128	10.967
	LNG		2.299	1.953	5.269	5.041	7.757
Difference (LNG-Diesel)			**0.097**	**-0.176**	**-1.101**	**-2.087**	**-3.210**
Net Ratepayer Impact ($million)							
	Diesel (new)		4.184	4.655	8.713	9.432	13.231
	LNG		3.231	3.799	6.982	6.725	9.850
Difference (LNG-Diesel)			**-0.953**	**-0.855**	**-1.731**	**-2.706**	**-3.381**

Notes:

1. Diesel capital costs retained as per LNG Part 3 proceeding (assumes unit 1 in-service at end of 2014 at $21.6 million and unit 2 in-service at end of 2015 at $11.1 million); each unit's depreciation (excluding decommissioning assumed for diesel units in 2014) starts in following year. Updated LNG capital costs as of 2017-18 GRA, including updated LNG third engine costs of $8.9 million assumed in-service Jan. 1, 2019 ($0.553 million with LNG for decommissioning Mirrlees units is now assumed after 2019). All LNG capital costs depreciated over 40 years, with units 1 and 2 in-service at mid-2015 (one-half year depreciation in 2015) and unit 3 in-service at start off 2019 (full year depreciation in 2019); return on mid-year rate base at 5.45%/year prior to 2017, and 5.00% thereafter.

2. Diesel fuel costs vary by year: for 2015 average Oct-Dec at 20.3 c/kWh new diesel (WH), 23.7 c/kWh existing diesel (grid average), $0.867 per litre; for 2016 average at Whitehorse Jan-Dec at 18.6 c/kWh new diesel (WH), 21.8 c/kWh other diesel, $0.798 per litre; for 2017 average at Whitehorse for Jan-Dec at 21.46 c/kW.h for new diesel and 25.51 c/kW.h for existing diesel; for 2018-2019, average at Whitehorse for Jan-April 2018 at 24.01c/kW.h new diesel and 28.55 c/kW.h for existing diesel.

3. LNG delivered fuel costs vary by year: for 2015, at 18.83 c/kWh (DCF Filing) based on May-Dec actual delivered fuel cost of $20.92/GJ and assumed (per DCF filing) 40.0% unit efficiency at 2.683 kWh/litre of LNG and 24.15 GJ/m^3 of LNG; for 2016, at 18.17c/kW.h actual average cost from inventory based on DCF Annual Report filing; for 2017, at 18.75 c/kW.h actual average delivered cost; for 2018-2019, at 17.48 c/kW.h actual average delivered cost for Jan-April 2018.

4. Updated LTA Default Diesel (GW.h) as per Table 2.2 of 2017-18 GRA: actual for 2015, 2016 and 2017 LTA as reported in DCF filing; 2018 LTA assumed the same as 2017; 2019 assume growth including some load for VG.

5. Percent of LTA thermal supplied by LNG as per DCF filing for 2015 (partial year impact) and 90% thereafter (per 2017-18 GRA assessments). Percent of LTA thermal supplied by new diesel at 50% based on capacity limits and assumed insufficient incentive to use for enhanced hydro storage during drought.

6. LNG capital costs assume $18.3 million third party contributions in 2015.

Table 1B: Updated Table 4-3 Ratepayer Impacts from Whitehorse Diesel-Natural Gas Conversion Project - ($million) (Project compared to New Diesel Alternative) Both LNG and Diesel Capital Costs after YDC Contribution of $18.3 million

		2014	2015	2016	2017	2018	2019
Capital cost ($million) at yr end							
Total	Diesel (new)	21.60	-7.20				
	LNG		23.63				8.9
Net	Diesel (new)	21.60	13.9	13.5	13.2	12.9	12.5
	LNG	0.00	23.3	22.7	22.2	21.6	29.7
Difference (LNG-Diesel)							
Annual Capital Cost ($million)							
Deprec	Diesel (new)		0.516	0.336	0.336	0.336	0.336
	LNG		0.295	0.591	0.591	0.591	0.813
Return	Diesel (new)		0.967	0.748	0.669	0.652	0.635
	LNG		0.636	1.256	1.123	1.093	1.280
Total	Diesel (new)		1.483	1.084	1.005	0.988	0.972
	LNG		0.931	1.847	1.713	1.684	2.094
Difference (LNG-Diesel)			**-0.552**	**0.763**	**0.708**	**0.695**	**1.122**
Annual Fuel Cost ($million)							
Forecast LTA Diesel (GWh)			10.0	10.5	27.1	27.1	41.7
% New	Diesel (new)		50%	50%	50%	50%	50%
	LNG		15.0%	90%	90%	90%	90%
Fuel Cost	Diesel (new)		2.202	2.128	6.370	7.128	10.967
	LNG		2.299	1.953	5.269	5.041	7.757
Difference (LNG-Diesel)			**0.097**	**-0.176**	**-1.101**	**-2.087**	**-3.210**
Net Ratepayer Impact ($million)							
	Diesel (new)		3.686	3.212	7.375	8.116	11.939
	LNG		3.231	3.799	6.982	6.725	9.850
Difference (LNG-Diesel)			**-0.455**	**0.587**	**-0.393**	**-1.391**	**-2.088**

Notes:

1. Diesel capital costs retained as per LNG Part 3 proceeding (assumes unit 1 in-service at end of 2014 at $21.6 million and unit 2 in-service at end of 2015 at $11.1 million, less assumed $18.3 million YDC contribution); each unit's depreciation (excluding decommissioning assumed for diesel units in 2014) starts in following year. Updated LNG capital costs as of 2017-18 GRA, including updated LNG third engine costs of $8.9 million assumed in-service Jan. 1, 2019 ($0.553 million with LNG for decommissioning Mirrlees units is now assumed after 2019). All LNG capital costs depreciated over 40 years, with units 1 and 2 in-service at mid-2015 (one-half year depreciation in 2015) and unit 3 in-service at start off 2019 (full year depreciation in 2019); return on mid-year rate base at 5.45%/year prior to 2017, and 5.00% thereafter.

2. Diesel fuel costs vary by year: for 2015 average Oct-Dec at 20.3 c/kWh new diesel (WH), 23.7 c/kWh existing diesel (grid average), $0.867 per litre; for 2016 average at Whitehorse Jan-Dec at 18.6 c/kWh new diesel (WH), 21.8 c/kWh other diesel, $0.798 per litre; for 2017 average at Whitehorse for Jan-Dec at 21.46 c/kW.h for new diesel and 25.51 c/kW.h for existing diesel; for 2018-2019, average at Whitehorse for Jan-April 2018 at 24.01c/kW.h new diesel and 28.55 c/kW.h for existing diesel.

3. LNG delivered fuel costs vary by year: for 2015, at 18.83 c/kWh (DCF Filing) based on May-Dec actual delivered fuel cost of $20.92/GJ and assumed (per DCF filing) 40.0% unit efficiency at 2.683 kWh/litre of LNG and 24.15 GJ/m^3 of LNG; for 2016, at 18.17c/kW.h actual average cost from inventory based on DCF Annual Report filing; for 2017, at 18.75 c/kW.h actual average delivered cost; for 2018-2019, at 17.48 c/kW.h actual average delivered cost for Jan-April 2018.

4. Updated LTA Default Diesel (GW.h) as per Table 2.2 of 2017-18 GRA: actual for 2015, 2016 and 2017 LTA as reported in DCF filing; 2018 LTA assumed the same as 2017; 2019 assume growth including some load for VG.

5. Percent of LTA thermal supplied by LNG as per DCF filing for 2015 (partial year impact) and 90% thereafter (per 2017-18 GRA assessments). Percent of LTA thermal supplied by new diesel at 50% based on capacity limits and assumed insufficient incentive to use for enhanced hydro storage during drought.

6. Both LNG and diesel capital costs assume $18.3 million third party contributions in 2015 [the diesel capital cost number shows negative as $11.1 million cost less $18.3 million contributions].

Table 2: Updated Table 4-3 – Capital Costs without YDC Capital Contributions: 2015-2019

		2014	2015	2016	2017	2018	2019
Capital cost ($million) at yr end							
Total	Diesel (new)	21.60	11.10				
	LNG		41.93				8.9
Net	Diesel (new)	21.60	32.2	31.4	30.6	29.8	29.0
	LNG	0.00	41.4	40.4	39.3	38.3	45.9
Difference (LNG-Diesel)							
Annual Capital Cost ($million)							
Deprec	Diesel (new)		0.516	0.794	0.794	0.794	0.794
	LNG		0.524	1.048	1.048	1.048	1.271
Return	Diesel (new)		1.466	1.732	1.550	1.510	1.470
	LNG		1.128	2.228	1.992	1.939	2.104
Total	Diesel (new)		1.982	2.526	2.343	2.304	2.264
	LNG		1.653	3.277	3.040	2.988	3.375
Difference (LNG-Diesel)			**-0.329**	**0.750**	**0.697**	**0.684**	**1.111**
Annual Fuel Cost ($million)							
Forecast LTA Diesel (GWh)			10.0	10.5	27.1	27.1	41.7
% New	Diesel (new)		50%	50%	50%	50%	50%
	LNG		15.0%	90%	90%	90%	90%
Fuel Cost	Diesel (new)		2.202	2.128	6.370	7.128	10.967
	LNG		2.299	1.953	5.269	5.041	7.757
Difference (LNG-Diesel)			**0.097**	**-0.176**	**-1.101**	**-2.087**	**-3.210**
Net Ratepayer Impact ($million)							
	Diesel (new)		4.184	4.655	8.713	9.432	13.231
	LNG		3.952	5.229	8.309	8.029	11.131
Difference (LNG-Diesel)			**-0.232**	**0.575**	**-0.404**	**-1.403**	**-2.100**

Notes:

1. Diesel capital costs retained as per LNG Part 3 proceeding (assumes unit 1 in-service at end of 2014 at $21.6 million and unit 2 in-service at end of 2015 at $11.1 million); each unit's depreciation (excluding decommissioning assumed for diesel units in 2014) starts in following year. Updated LNG capital costs as of 2017-18 GRA, including updated LNG third engine costs of $8.9 million assumed in-service Jan. 1, 2019 ($0.553 million with LNG for decommissioning Mirrlees units is now assumed after 2019). No $18.3 million YDC contribution assumed for LNG capital costs. All LNG capital costs depreciated over 40 years, with units 1 and 2 in-service at mid-2015 (one-half year depreciation in 2015) and unit 3 in-service at start off 2019 (full year depreciation in 2019); return on mid-year rate base at 5.45%/year prior to 2017, and 5.00% thereafter.

2. Diesel fuel costs vary by year: for 2015 average Oct-Dec at 20.3 c/kWh new diesel (WH), 23.7 c/kWh existing diesel (grid average), $0.867 per litre; for 2016

average at Whitehorse Jan-Dec at 18.6 c/kWh new diesel (WH), 21.8 c/kWh other diesel, $0.798 per litre; for 2017 average at Whitehorse for Jan-Dec at 21.46 c/kW.h for new diesel and 25.51 c/kW.h for existing diesel; for 2018-2019, average at Whitehorse for Jan-April 2018 at 24.01c/kW.h new diesel and 28.55 c/kW.h for existing diesel.

3. LNG delivered fuel costs vary by year: for 2015, at 18.83 c/kWh (DCF Filing) based on May-Dec actual delivered fuel cost of $20.92/GJ and assumed (per DCF filing) 40.0% unit efficiency at 2.683 kWh/litre of LNG and 24.15 GJ/m^3 of LNG; for 2016, at 18.17c/kW.h actual average cost from inventory based on DCF Annual Report filing; for 2017, at 18.75 c/kW.h actual average delivered cost; for 2018-2019, at 17.48 c/kW.h actual average delivered cost for Jan-April 2018.

4. Updated LTA Default Diesel (GW.h) as per Table 2.2 of 2017-18 GRA: actual for 2015, 2016 and 2017 LTA as reported in DCF filing; 2018 LTA assumed the same as 2017; 2019 assume growth including some load for VG.

5. Percent of LTA thermal supplied by LNG as per DCF filing for 2015 (partial year impact) and 90% thereafter (per 2017-18 GRA assessments). Percent of LTA thermal supplied by new diesel at 50% based on capacity limits and assumed insufficient incentive to use for enhanced hydro storage during drought.

6. Both LNG and diesel capital costs exclude any third party contributions.

Draft List of Undertakings from 2017/18 GRA Hearing

#	Transcript Reference	Response Provided	Response Outstanding
1.	Page 69, lines 24-25 & page 70, line 1	Exhibit B-23	
2.	Page 79-80	Page 113, lines 10-18	
3.	Page 93-94	Page 219, lines 10-15 & page 220, lines 1-5	
4.	Page 111, lines 14-19	Page 221, lines 1-4	
5.	Page 192	Page 221, lines 15-24	
6.	Page 193	Page 221, lines 15-24	
7.	Page 209	Page 209, lines 12-14	
8.	Page 210, lines 21-24	Page 220, lines 14-19	
9.	Page 228, lines 21-13	Page 231, lines 5-8	
10.	Page 259, lines 4-7		Advise as to whether there is an estimated cost for the study referred to in response to JM-YEC-1-40.
11.	Page 261, lines 4-7	Page 262, lines 22-25 & page 263, lines 1-4	
12.	Page 264, lines 18-23	July 3, 2018 Correspondence	
13.	Page 266, lines 20-25 & page 267, lines 1-2	July 3, 2018 Correspondence	
14.	Page 272, lines 12-15	Page 299, lines 9-22	
15.	Page 273, lines 20-22	Page 299 line 25, & page 300, lines 1-3	
16.	Page 305, lines 7-10		Reconciliation of these three numbers: $51,863,000, $49,723,000 and $47,071,000.
17.	Page 312, lines 19-25		Clarify why the CEA SAIFI five-year average of 2.81 was less than the Yukon Energy five-year average of 10.23.
18.	Page 338, lines 20-23		Provide sole-sourced contracts for feasibility projects leading up to the construction of the LNG plant and the underlying contracts.
19.	Page 395, lines 8-10	Page 434, lines 15-17	
20.	Page 402, lines 11-16		For 2016 Resource Plan, provide the total cost of what is planned to be put onto rate base and the costs broken down into internal costs, and the costs for consultant groups and which consultant group was hired.
21.	Page 453, lines 22-25		Provide the cost of the transformer that was installed as part of the Mayo to Dawson transmission Line project in 2004.
22.	Page 454, lines 8-12		Advise as to whether, at the time the transformer was built in 2004, there were ground clearance and fencing height

			standards for transformers.
23.	Page 454, lines 19-23		Advise as to whether the transformer that was installed as part of the Mayo to Dawson transmission line project in 2004 was built to the standards at the time.
24.	Page 472, lines 22-24		Advise as to whether, on the SCADA upgrades, there was any analysis done to quantify the benefits.
25.	Page 497, lines 508		Verify the RTUS at Aishihik were installed in 1975, and that there has been no replacement of those RTUS at Aishihik.
26.	Page 498, lines 4-7		Advise how many of the RTUS are of a similar vintage to what's in Whitehorse in the YEC system and the timeline for replacement.
27.	Page 509 lines 21-25 & 510, line 1		Provide a listing of existing positions in YEC functions that they currently serve that would otherwise be done by outside consultants, and the related labour charges.
28.	Page 521, lines 3-5		Undertaking to clarify the following: • Why depreciation expense varies for 2017 and 2018 under existing versus proposed scenarios, given that PPE balances are the same (see Exhibit B-1, Tab 7, schedule 3 – and statement in YUB-YEC-1-17 that attributes impact to deferred overhauls coming into rate base with GRA); and • Why the amortization dollars differ for existing versus proposed scenarios as shown in Exhibit B-1, Tab 7, Schedule 6, and how related contributions were addressed for 2017 and 2018.
29.	Page 529, lines 8-11		Summarize the changes between the 2012/13 Planning Cost Accounting Policy (as referred to in Board Order 2013-01) and the Planning Cost Accounting Policy provided as Appendix 5.1 to the current GRA.
30.	Page 533, lines 3-7		Provide the composition of the deferred cost expense amounts, as listed in Tab 7, Schedule 5, Line 7, by study (i.e., by categories in the table in YUB-YEC-2-26) on a pre and post contribution basis for actual 2016 and proposed 2017 and 2018 amounts.
31.	Page 535, lines 10-12		Reconcile differences in terminology and amounts for "regulatory costs" in tables of YUB-YEC-1-12 and YUB-YEC-2-26.

32.	Page 535, lines 2-23		In regards to the prior undertaking (#31), advise if the different categories and amounts (as between the two IRs) are net of contributions, and any related differences in terminology.
33.	Page 535, line 24 to 536, line 21		Confirm where DSM amortization costs for 2017 and 2018 are in YUB-YEC-2-26 table (these amounts are included at line 7 of schedule 5, and table 2 of YUB-YEC-1-12).
34.	Page 543, lines 20-25		Advise as to how the GRA forecast numbers compare in 2017 and to June 2018, with actual and as to what the expenditures are currently expected 2018 expenditures for the environmental management cost category.
35.	Page 551, line 3 to page 553, line 5		Update Tab 7 of the GRA with 2017 actual results; and provide separate updates using the LTA forecast and the ST forecast.
36.	Page 553, line 20 to Page 556, line 16		Update Tab 7 of the GRA with 2018 forecast that includes industrial and secondary sales load forecast updates per the Opening Statement using both short-term and long-term average fuel requirements.
37.	Page 593, lines 22-25		Explain the difference in the levels of new debt financing between the two forecasts (original and alternative) for 2017 and 2018 (reference page 3-22 in Application).
38.	Page 600, lines 18-21; Page 621, line 8 to Page 622, line 23.		Advise as to whether FortisBC Electric has a deferral or contingency account (and if so, how such an account differs from YEC's DCF) for changes in hydro-generation from GRA forecasts due to changes in forecast water levels, as such changes affect thermal generation fuel costs, with the result that such cost variances are ultimately borne by ratepayers.
39.	Page 601, lines 13-16		Verify as to whether FortisBC Electric utilizes an N-1 Criteria for capacity planning purposes.
40.	Page 615, lines 18-22		Clarify wording issue in response to the last bullet of YUB-YEC-1-36.
41.	Page 637, lines 18-23		Provide an example as to how the ERA would work if its operation results in YEC making a payment to AEY in relation to the ERA account.