Undertaking # 36 at Page 553, line 20 to Page 556, line 16 - Revised

Mr. Mollard provided an undertaking to provide a 2018 revenue requirement forecast that includes industrial and secondary sales load forecast updates per the Opening Statement using both short-term and long term average fuel requirements.

Yukon Energy Response:

Please see the attached table, which provides the following 2018 revenue requirement forecasts (two short-term forecasts are included to reflect the volatility of ST forecasts for second test year, depending on loads forecast for the first test year):

1. **Proposed 2018** – the forecast as filed in June 2017 (Exhibit B-1), with LTA hydro and thermal generation.

2. **Update 2018 –** the Proposed (which assumes LTA hydro and thermal generation as per Table 3.4-1 of Exhibit B-1) adjusted for the following updated industrial load and secondary load forecasts per the Opening Statement:
    a. Industrial – Updated industrial forecast sales load at 32,192 MW.h (versus GRA forecast of 38,219 MW.h), based on actual January-June of 22,361 MW.h and revised forecast for balance of year of 9,831 MW.h per Minto information.[1]
    b. Secondary - Updated secondary forecast sales load at 2,059.48 MW.h (versus GRA forecast of 11,464 MW.h), based on six month actual of 18.48 MW.h and revised forecast for balance of year of 2,041 MW.h.

3. **Update 2018 ST#1 –** The 2018 Update with the revised Industrial and Secondary load forecasts, using short-term fuel requirements[2] based on GRA forecast loads for 2016 and 2017 as originally filed.

4. **Update 2018 ST#2** - The 2018 Update with the revised Industrial and Secondary load forecasts, using short-term fuel requirements (as provided in the ST Alternative GRA Forecast, Exhibit B-14, Appendix 2.2, with assumed 60/40 LNG/diesel split) based on actual grid loads for 2016 and 2017, i.e., the scenario if actual loads for 2016 and 2017 had been forecast at the time of GRA filing.

The updated information is limited to the two specific load forecast items in the Opening Statement (Exhibit B-22), as noted above. LTA was assessed using the Exhibit B-1

[1] Minto is the only industrial in 2018 forecasts.
[2] As provided in the ST Alternative GRA Forecast, Exhibit B-14, Appendix 2.2, with assumed 60/40 LNG/diesel split.

Table 3.4-1, without re-running YECSIM to adjust this table to reflect the major change in annual load shape.[3] In contrast, the ST hydro forecasts re-ran the ST hydro model and thereby reflected impacts related to changes in the annual load shape. Other updates related to load forecast as well as O&M costs and rate base are not addressed.

As reviewed in response to YUB-YEC-1-3 and the attached table, load forecast updates impact the following revenue requirement forecast elements:

1. Revenues at existing rates;

2. Fuel costs (based on LTA or ST forecast hydro generation related to changes in firm grid load, assuming operation of a DCF under either case and GRA fuel price forecasts as well as GRA thermal generation maintenance fuel forecasts);

3. Mayo B Flexible Debt interest (lower generation due to lower industrial and secondary sales will reduce the interest on this debt); and

4. Working capital (to the extent that changes in fuel costs impact working capital).

In summary, the attached table shows the two load forecast adjustments result in a reduction in the forecast 2018 revenue requirement of $0.712 million, assuming LTA hydro and thermal generation based on Table 3.4-1 of the GRA. The reduction in sales revenue at existing rates is slightly higher at $0.799 million, indicating a small increase in the overall revenue shortfall to be recovered from increased rates.

In reality, the reduction in 2018 revenue requirement would likely be smaller than indicated in the attached table when the DCF table is updated as required for the material change in annual load shape[4], i.e., the LTA thermal generation will be higher than assumed in Update 2018 due to the higher-than-GRA forecast loads in the early winter months (which months drive annual thermal LTA) and the much lower-than-GRA forecast loads for the last six months.

With these adjustments, the ST#1 forecast revenue requirement in the table is not materially different from the LTA forecast, reflecting an increase in ST thermal

[3] The DCF Term Sheet (Attachment 3.4-1 of Exhibit B-1) requires at page 3.4-14 that YEC will provide the Board, for review and approval, an update to Table 3.4-1 when required in future to address material changes in LTA hydro system capability due to changes in loads, installed capacity, licensing/ permits or other factors. The updated load forecast for 2018 materially changes the annual load shape from that assumed for Table 3.4-1, with higher industrial loads in the first few winter months and very low industrial loads for the last six months.

[4] That is, the significant reduction in load to serve Minto.

generation cost from GRA forecast filings.[5] However, the forecast revenue requirement gap between LTA and ST#1 Updates would widen with required updates to the DCF table and the LTA determination to reflect the material change in annual load shape.

In contrast, the ST#2 forecast shows a materially higher revenue requirement than the GRA forecast (under both LTA and ST thermal forecasts) due to the change in ST fuel cost forecasts. This shows the impact in the second year of a GRA filing (2018), using the ST hydro forecast approach, if materially higher grid loads are forecast in the first year of the GRA filing (2017).

Review of the two ST scenarios in the attached table demonstrates the volatile nature of short-term hydro assessments.

[5] YUB-YEC-2-11(b) shows the ST Alternative Forecast for 2018 at $49.16 million based on the GRA forecast loads and costs, with fuel cost at $1.665 million (8.2 GW.h thermal generation). The Update ST#1 higher thermal at 9.4 GW.h reflects higher grid load in the January-April period having a greater thermal generation impact than the lower grid load from July to December.

Summary Update for 2018 Revenue Requirement ($000)

	Proposed 2018	Update 2018	Update 2018 ST#1	Update 2018 ST#2
Sales Forecast ($000)				
Industrial[1]	4,198	3,952	3,952	3,952
Other YEC Firm[2]	31,813	31,813	31,813	31,813
Total YEC-Firm	36,011	35,765	35,765	35,765
Secondary[3]	642	115	115	115
Total Sales - base rates	36,653	35,880	35,880	35,880
Rider J	6,373	6,347	6,347	6,347
Total Sales	43,026	42,227	42,227	42,227
Revenue Requirement ($000)				
Fuel[4]	2,368	1,918	1,885	3,630
Mayo B Flexible Debt change[6]	-	(260)	(260)	(260)
Return on Working Capital[5]	256	255	255	259
Return on Balance of Rate Base[2]	14,092	14,092	14,092	14,092
Other Revenue Requirement[2]	33,148	33,148	33,148	33,148
Total Revenue Requirement	49,864	49,152	49,119	50,868
Rate Base ($000)				
Adjusted Working Capital[5]	5,210	5,183	5,181	5,264
Balance of net mid-yr rate base[2]	286,417	286,417	286,417	286,417
Total mid-year net rate base	291,627	291,600	291,598	291,681

Notes:

1 Updated Industrial forecast load at 32,192 MWh (vs. GRA forecast 38,219 MWh), based on actual January-June and revised forecast for balance of 2018.

2 Per GRA as originally filed.

3 Updated Secondary forecast load at 2,059.48 MW.h, based on six month actual and updated forecast for balance of months.

4 "Update 2018" assumes LTA thermal per GRA Table 3.4-1 of 11,641 MWh for adjusted load and 90/10 LNG/diesel; "Update 2018 ST#1"assumes ST based on GRA forecast loads for 2016 and 2017 with ST thermal for 2018 of 9,362 MWh for adjusted load and 60/40 LNG/diesel;"Update 2018 ST#2"assumes ST based on actual loads for 2016 and 2017 with ST thermal for 2018 of 18,387 MWh for adjusted load and 60/40 LNG/diesel. All updated forecasts include $75k for forecast maintenance fuel costs.

5 Impacts of sales & fuel cost changes on working capital; assume GRA 4.92% return.

6 Reduced generation (industrial & secondary) reduces Mayo B Flexible Debt interest.