

Yukon Utilities Board

Board Order 2018-10

Appendix A: Reasons for Decision
December 27, 2018

Contents

1	Introduction.....	1
2	Background	2
3	Yukon energy system sales and generation	4
3.1	Overview	4
3.2	Sales forecast.....	5
3.2.1	Wholesale sales to ATCO Electric Yukon.....	6
3.2.2	Major industrial sales.....	8
3.2.3	YEC firm retail sales.....	10
3.2.4	Secondary sales.....	10
3.2.5	Power generation	11
3.3	Peak demand forecast and dependable capacity requirement	12
4	Revenue requirement.....	13
4.1	GRA forecasts – Long-term average versus short-term.....	13
	Views of the Board	15
4.2	Overview	16
4.3	Use of 2017 actual results	17
4.4	Fuel and purchased power.....	19
4.5	Non-fuel operating and maintenance expenses.....	22
4.5.1	Labour	24
4.5.2	Production	27
4.5.3	Transmission, Distribution and Brushing Costs, including the Vegetation Management Deferral Account.....	28
4.5.3.1	Transmission.....	28
4.5.3.2	Distribution.....	29
4.5.3.3	Transmission and Distribution Brushing Costs	29
4.5.3.4	Vegetation Management Deferral Account	31
4.5.4	General operation and maintenance costs.....	32
4.5.5	Administration costs	33
4.5.6	Insurance and Reserve for Injuries and Damages (RFID) account.....	34
4.5.6.1	Reserve for injuries and damages account.....	35
4.5.6.2	Property taxes	36
4.6	Rate base, depreciation and amortization.....	37
4.7	Deferral and reserve accounts	41
4.7.1	Hearing cost reserve account	41
4.7.2	Comments on YEC’s deferral and reserve accounts.....	42
4.8	Return on rate base (interest costs and return on equity)	43
4.8.1	Costs of debt	43
4.8.2	Capital structure and return on common equity.....	45
4.8.3	Cost of Equity	46
4.8.4	Basis for Risk Premium	47
4.8.4.1	BCUC considerations in determining the risk premium for FortisBC (Electric)	49
4.8.4.2	Risk premium due to small size and comparability to PNG-West	52
4.8.4.3	Comparability to AEY.....	52
4.8.4.4	Generation Risk	53

4.8.4.5	Risk mitigation through the DCF	55
4.8.4.6	Approved risk Premium.....	55
4.9	Stabilization mechanisms.....	56
4.9.1	Rider F	56
4.9.2	Diesel contingency fund (DCF).....	58
4.9.3	DCF Cap Update.....	62
5	Rates	64
5.1	Secondary Sales	65
5.2	Wholesale Rates	65
5.3	Other Rate Matters	66
6	Capital projects	67
6.1	Capital projects.....	67
6.1.1	Major projects over \$1 million	69
6.1.1.1	Project Aishihik Third Turbine.....	69
6.1.1.2	Aishihik Elevator Shaft Structural Steel Rehabilitation	69
6.1.1.3	Aishihik electrical and control upgrades	71
6.1.1.4	Communications upgrades.....	74
6.1.1.5	Liquid natural gas (LNG) plant	76
6.1.1.6	LNG third engine.....	78
6.1.1.7	Other major projects	80
6.1.2	Projects between \$100,000 and \$1 million	81
6.1.2.1	Aishihik control structure refurbishment.....	82
6.1.2.2	Faro diesel building ventilation	82
6.1.2.3	Wareham dam blackstart generator	82
6.1.2.4	Whitehorse Wind 1 decommission.....	83
6.1.2.5	Dawson P158 T1/T2 transformer	83
6.1.2.6	Substation protection and control minor upgrades	84
6.1.2.7	Transmission system protection upgrades	84
6.1.2.8	Callison voltage regulator automation.....	84
6.1.2.9	Building condition report response.....	85
6.1.2.10	Stewart-Minto local SCADA.....	85
6.1.2.11	Other capital projects between \$100,000 and \$1 million	85
6.1.3	Deferred costs	86
6.1.4	Deferred - major projects over \$1 million	86
6.1.4.1	Aishihik generating station water use licence renewal project.....	87
6.1.4.2	Battery energy storage system project.....	87
6.1.4.3	Thermal plant.....	88
6.1.4.4	Demand side management.....	90
6.1.4.5	Resource plan update.....	92
6.1.4.6	Gladstone diversion	93
6.1.4.7	Marsh Lake Storage.....	94
6.1.4.8	Mayo Lake Storage.....	95
6.1.5	Deferred - Projects Between \$100,000 and \$1 million.....	96
6.1.5.1	Mayo and Aishihik Climate Change Study	97
6.1.5.2	Time-of-use rate structure and smart grid	97
6.1.5.3	Mt Sumanik Wind Feasibility Study	97
6.1.5.4	Northern Diesel Plant Location Study.....	98
6.1.5.5	Whitehorse hydro uprate.....	98

	6.1.5.6	Small hydro.....	99
6.2		Policies	99
	6.2.1	Planning cost accounting policy (PCAP).....	99
	6.2.2	New Vegetation Management Policy	101
	6.2.3	DSM accounting policy	104
Summary of Directions			106

List of Tables

Table 1.	Summary of energy sales (GW.h) 2013-2018	6
Table 2.	Summary of energy sales and losses and generation (GW.h) 2013-2018	11
Table 3.	Yukon Energy Revenue Requirement (\$000)	17
Table 4.	Yukon Energy Revenue Requirement (\$000)	18
Table 5.	Fuel and purchased power (\$000)	19
Table 6.	Diesel assumptions	20
Table 7.	Comparison of LTA and ST forecasts for fuel costs.....	20
Table 8.	Comparison of LNG and diesel assumptions.....	20
Table 9.	Fuel and purchased power (\$000)	21
Table 10.	Non-Fuel Operating and Maintenance expenses (\$000)	22
Table 11.	Employee Complement History (FTEs)	25
Table 12.	Production Costs (\$000).....	28
Table 13.	Transmission Costs (\$000).....	29
Table 14.	Distribution Costs (\$000).....	29
Table 15.	Total Net Transmission and Distribution Brushing Costs (\$000)	30
Table 16.	Transmission and Distribution Costs (\$000)	31
Table 17.	General Operation and Maintenance Costs (\$000).....	33
Table 18.	Administration Costs (\$000).....	33
Table 19.	Insurance costs and the Reserve for Injuries and Damages (\$000)	35
Table 20.	Property taxes (\$000).....	37
Table 21.	Mid-year rate base (\$000)	38
Table 22.	Depreciation and amortization (\$000)	39
Table 23.	YEC 2017-2018 Return on Rate Base Parameters	43
Table 24.	Deferred – projects between \$100,000 and \$1 million (\$ million).....	96
Table 25.	Tree-caused outages	102

1 Introduction

1. YEC is the main generator and transmitter of electrical energy in Yukon, providing transmission facilities for the Whitehorse-Aishihik-Faro and Mayo-Dawson grid systems which have been joined by the Carmacks-Stewart transmission system through stages 1 and 2 of the Carmacks-Stewart Transmission Project. YEC supplies power through wholesale electricity sales to the Yukon Electrical Company Ltd. (YECL carrying on business as ATCO Electric Yukon [AEY]).

2. On June 22, 2017, Yukon Energy Corporation (YEC, Company or Applicant) filed with the Yukon Utilities Board (Board) an application, pursuant to the *Public Utilities Act* and *Order-in-Council 1995/90*, for approval of its forecast revenue requirements for the 2017 and 2018 test years and of interim retail rates effective January 1, 2017.

3. More specifically, YEC is seeking approval of a revenue requirement of \$48.544 million for 2017 and \$49.864 million for 2018.¹ YEC is seeking approval of the following costs, revenues and other related matters, which form part of the requested revenue requirements:

- Fuel and purchase power costs forecast of \$2.381 million for 2017 and \$2.407 million for 2018 plus approval to adjust diesel prices and delivered LNG prices used in setting fuel costs to reflect current market conditions. Approval to assume that long-term average (LTA) thermal generation requirements are supplied with a combination of 90 percent LNG and 10 percent diesel generation. Approval to revise Rider F to include pricing related to the delivered cost of LNG effective January 1, 2017, and to defer to the Diesel Fuel Price Variance Account (DFPVA) the variance in actual delivered cost of LNG compared to the delivered cost of LNG included in the most recent General Rate application for all thermal-electric generation. Approval to include deferred LNG price variances in the amounts collected or refunded to customers through Rider F pursuant to the Rider F - Fuel Adjustment Rider & Deferred Fuel Price Variance Policy. Approval of required adjustments to the Rider F Policy to incorporate reference to LNG pricing in the DCF. Further, YEC sought approval of YEC's DCF Term Sheet provided in Attachment 3.4-1 of Appendix 3.4 of the application.
- Non-fuel operating and maintenance costs forecast of \$22.060 million for 2017 and \$22.016 million for 2018, including approval to increase the appropriation to the reserve for injuries and damages to \$0.267 million from the current \$0.190 million starting in 2017 and approval to amortize the remaining balance of \$1.059 million over a five-year period. YEC also requested approval, starting in 2017, to amortize the 2016 balance of the vegetation management deferral account over 10 years (\$0.222 million per year) and to eliminate the requirement to defer brushing costs in excess of 2011 actual brushing costs.
- Depreciation and amortization expense forecasts of \$10.814 million for 2017 and \$11.094 million for 2018, including approval for the new Planning Cost Accounting

¹ YEC application, page 4, PDF page 5. (Amounts are before deductions of non-rate revenues.)

Policy, the Demand Side Management Accounting Policy and to amortize the 2016 credit balance in the regulatory hearing reserve deferral account of \$0.973 million over a five-year period and to decrease the annual provision starting in 2017 to \$0.250 million.

- Mid-year forecast rate base costs of \$274.459 million for 2017 and \$291.627 million for 2018.
- \$13.289 million in 2017 and \$14.348 million in 2018 for return on rate base, based on an allowed rate of return on equity of 8.82 percent for 2017 and 2018, respectively.

4. YEC also sought approval of interim refundable rates effective September 1, 2017, through Rider J rate increases for retail and industrial customers. The Board approved interim rate adjustments of 16.51 percent for retail customers and 12.86 percent for industrial customers on a refundable basis effective September 1, 2017, by way of Rider J through Board Order 2017-06 issued August 21, 2017.

2 Background

5. On July 4, 2017, the Board issued Board Order 2017-04 regarding the application in which the Board ordered YEC to hold a workshop on the application on August 3, 2017 in Whitehorse and to publish a Notice of Application, workshop and hearing no later than July 10, 2017 in such appropriate local news publications in YEC's service area to provide adequate notice to the public. YEC was also ordered to make the application and supporting materials available on YEC's website and to make hard copies available upon request to YEC. Board Order 2017-04 proposed a proceeding schedule for the application with a hearing to commence on November 28, 2017.

6. On June 30, 2017, the Minister of Justice authorized the Board to incur the expenses necessary to conduct a public hearing into the application pursuant to Section 50 of the Act.

7. YEC held a workshop in Whitehorse on August 3, 2017 where the application was reviewed and certain portions explained in greater detail.

8. The Board, through Board Order 2017-05 issued July 27, 2017, granted intervener status for this proceeding to the following:

- AEY
- John Maissan (Mr. Maissan)
- Utilities Consumers' Group (UCG)
- Yukon Conservation Society (YCS)
- The City of Whitehorse (CW)

9. Round 1 information requests (IRs) were issued to YEC on August 25, 2017. Responses to those IRs were received on September 22, 2017. The UCG filed a motion for further and better information responses on September 28, 2017. Mr. Maissan filed a similar motion on

October 3, 2017. Regarding the motions, the Board invited YEC² to respond to the motions by October 10, 2017 and Mr. Maissan and UCG to provide reply comments by October 13, 2017. The Board also suspended the proceeding schedule. The Board provided its ruling on the motions through Board Order 2017-09 on November 15, 2017.

10. On September 12, 2017, the Court of Appeal of Yukon released a judgement on an appeal by YEC related to certain aspects of Board Order 2015-06. The judgement set aside the order of the Board related to the issues of the DCF and the wholesale rates provision in Section 7 of *Rate Policy Directive, Order-in-Council* 1995/90. The court remitted the matter back to the Board with directions “to set a wholesale rate that enables Yukon Energy to recover all of its diesel generation costs, which costs include any net payment made by Yukon Energy attributable to AEY's above-forecast wholesale purchases of electricity.”

11. On September 22, 2017, the Board issued a letter requesting parties to comment on the Court of Appeal of Yukon judgement. Parties provided comments by September 28, 2017. The Board issued Board Order 2017-08³ on October 18, 2017 in which it ordered:

- YEC to file a separate two-part application to comply with the direction from the Yukon Court of Appeal and the further directions of the Board within 30 days of the issuance of the order from the Yukon Court of Appeal. The first part of the application is to address 2012 Energy Reconciliation Adjustment (ERA) issues. The second part of the application is to address how YEC proposes to address DCF, ERA, wholesale rates and long-term hydro generation for the period of 2017 forward;
- Effective January 1, 2017, YEC to continue to treat the DCF as a placeholder to be adjusted upon final determination of the Board in the separate application to be established in response to the Yukon Court of Appeal decision;
- YEC to provide an alternative general rate application (GRA) forecast using a short-term hydroelectric forecast for the test period in question and any consequential changes to the thermal generation forecast, removing any DCF references in that alternative forecast and filing the alternative forecast within 60 days of the issuance of this order; and
- The GRA process schedule established in Order 2017-04 and revised by the October 4, 2017 letter from the Board to all parties was suspended and the process schedule revised as outlined in Appendix A to this Order.

12. YEC filed a letter in response to Board Order 2017-08 on December 6, 2017. The Board issued a letter on December 15, 2017 requesting comments from parties on how to proceed with YEC's DCF-ERA two-part application. Comments were received from interveners on January 16, 2018, and reply comments were received from YEC on January 18, 2018. Board Order 2018-02 was issued on January 31, 2018. In this order, the Board determined that a

² The Board issued correspondence on October 2, 2017 outlining the process for the UCG motion and issued further correspondence on October 4 suspending the current proceeding schedule and outlining the process with respect to the motion from Mr. Maissan.

³ Board Order 2017-08 was corrected by Board Order 2017-08 Errata on October 19, 2017.

separate written process would be set to consider the first part of the two-part DCF-ERA application and that the second part of the two-part application would be considered in this GRA proceeding. Board Order 2018-02 provided the revised process steps for this GRA proceeding.

13. YEC filed its Alternative GRA (short term or ST) Forecast on December 18, 2017.

14. Board Order 2018-03 was issued February 20, 2018 to revise the process schedule in response to a request from YEC to change the public oral hearing date due to the unavailability of its legal counsel and key members of its witness panel.

15. Round 2 IRs were issued to YEC on March 14, 2018, and responses to those IRs were submitted by YEC by April 6, 2018.

16. Intervener evidence was submitted by CW on April 20, 2018. IRs to CW on its evidence were issued on May 4, 2018, and responses to those IRs were received from CW on May 18, 2018.

17. YEC filed rebuttal evidence on June 1, 2018, and a public oral hearing took place in Whitehorse on June 26-28, 2018.

18. YEC filed undertakings given at the hearing on July 3, 13, 20 and 23, 2018, respectively. The Board issued a letter on July 23, 2018 revising the remaining process schedule to allow for IRs on YEC's undertakings.

19. YEC provided its responses to the IRs on its undertakings on July 27, 2018. Written final argument was received August 9, 2018, and written reply argument was submitted by August 23, 2018. The Board considers the record of the proceeding closed on August 23, 2018.

20. In reaching the determinations contained within this decision, the Board has considered all relevant materials comprising the record of this proceeding, including the evidence and argument provided by each party. Accordingly, references in this decision to specific parts of the record are intended to assist the reader in understanding the Board's reasoning related to a particular matter and should not be taken as an indication that the Board did not consider all relevant portions of the record with respect to that matter.

3 Yukon energy system sales and generation

3.1 Overview

21. YEC is the main generator and transmitter of electricity in Yukon, accounting for over 90 percent of annual Yukon power generation and providing 138 kilovolt (kV) and 69 kV transmission facilities for the Yukon Integrated System.

22. YEC directly serves about 2,100 customers at the distribution (retail) level (about 10.5 percent of all electrical retail customers in Yukon), most of whom live in and around Dawson City, Mayo and Faro. Indirectly, YEC also provides power to Yukon retail customers served on the Yukon Integrated System (including those located in Whitehorse, Carcross,

Carmacks, Haines Junction, Ross River and Teslin, Pelly Crossing, Keno and Stewart Crossing) through its wholesale sales to AEY.

23. YEC submitted that, starting in 2014, firm load supplied to non-industrial customers on the Yukon Integrated System has fallen below the actual and approved forecast load for 2013 due to a decline in firm wholesales to AEY.

24. YEC indicated that industrial sales under Primary Industrial Rate Schedule 39 currently include only sales to the Capstone Mining Corp (Minto mine) and that no other industrial customer sales are forecast for the test years. Since 2013, firm grid load supplied to industrial customers has fallen below the actual and approved forecast load for 2013, except 2016, reflecting early shut down of the Alexco Resources Bellekeno mine in the last half of 2013. YEC further indicated that the Whitehorse Copper Tailings industrial load that was forecast to be supplied by AEY in the 2013 YEC Compliance Filing has not materialized to date.

25. YEC stated that the 2013 compliance filing included no forecast for secondary sales, since non-firm secondary sales had been interrupted on a sustained basis since September 2010 and a number of secondary sales customers had converted to primary supply for their electric heating loads. Actual secondary sales ranged between 3.9 and 7.0 gigawatt hour (GWh) from 2013 to 2016 and are forecast to increase to approximately 11.5 GWh in the 2017 and 2018 test years.

26. YEC added that, due to higher than long-term average water and lower than forecast grid load, hydro generation supplied 98.4 percent to 99.5 percent of grid load from 2013 to 2016, compared to the approved 2013 Compliance Filing forecast of 97 percent.

27. YEC indicated that, for the purpose of the 2017/2018 test years, hydro and thermal generation forecasts are based on LTA hydro and wind generation. YEC also referenced the 2013 GRA, highlighting increasing reliance on thermal generation on the Yukon hydro grid. In 2014, a diesel-natural gas conversion project was approved at YEC's Whitehorse facility to meet grid capacity requirements. The LTA thermal generation forecast for 2018 is 14.5 GW.h, as compared with 11.0 GW.h forecast for 2013 in the approved Compliance Filing.

28. Notwithstanding declines in firm energy generation requirements, YEC submitted that ongoing experience is demonstrating that winter peak hour generation loads have increased since the 2013 Compliance Filing, with the 2016 peak exceeding 88 MW, compared to the 2013 Compliance Filing forecast of 80 MW. Peak generation load, including the Minto mine, is forecast at 91.8 MW for 2017 and 92.9 MW for 2018.

3.2 Sales forecast

29. YEC submitted that total forecast sales are 397.9 GW.h for the 2017 test year and 398.6 GW.h for the 2018 test year. In the table below, approved, actual and forecast sales are given for the years 2013-2018.

Table 1. Summary of energy sales (GW.h) 2013-2018

Sales Group	2013 Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Forecast	2017 Actual	2018 Forecast
Industrial	40.6	40.5	36.3	37.2	41.2	38.2	43.4	38.2
Residential	12.4	13.4	13.3	13.1	13.4	13.6	15.0	13.7
General Service	22.6	22.3	23.6	24.6	25.0	25.3	26.1	25.4
Street & Space lights	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2
Total YEC – Firm Retail & Industrial	75.9	76.5	73.5	75.2	79.8	77.4	84.8	77.6
Wholesales	307.1	307.9	295.3	298.0	301.2	309.0	328.4	309.5
Total YEC – Firm	383.1	384.4	368.8	373.1	381.0	386.4	413.2	387.1
Secondary Sales	0	4.0	5.4	7.0	4.8	11.5	8.4	11.5
Total Company	383.1	388.4	374.2	380.2	385.9	397.9	421.6	398.6

Source: Application June 2017, Table 2.1, page 2-17. 2017 Actuals are taken from Undertaking 35, Attachment 1, schedule 9.

3.2.1 Wholesale sales to ATCO Electric Yukon

30. As shown in the table above, YEC energy sales on the Yukon Integrated System are primarily made up of firm wholesale sales to AEY.

31. YEC stated that AEY annually provides YEC with its forecast power purchase estimate net of forecast generation from its Fish Lake hydro plant. YEC compares this forecast to its current year budget for wholesales and recent actual results as well as regression analysis simulations. Based on a collective review of these comparisons, as well as management's own growth expectations, a final budget figure is selected.

32. For this application, YEC submitted that firm wholesales to AEY have shown material changes since the last GRA. In 2013, this was due to the Whitehorse Copper Tailings (WCT) industrial load included in the 2013 approved forecast not materializing. A further decline was seen in 2014 because of an increase in Fish Lake hydro generation of 6.4 GW.h. Before Fish Lake hydro impacts, AEY's grid firm load requirements in 2014 were about 6.1 GW.h lower than AEY's actual requirements in 2013. Firm wholesales in 2015 and 2016 increased slightly over 2014 levels.

33. Multi-variate regression assessments by YEC of monthly wholesale changes from January 2013 through September 2016, excluding Fish Lake hydro generation impacts, highlighted a strong correlation between AEY's monthly load on the grid and Whitehorse Heating Degree Days (HDD). Whitehorse temperatures during 2014 - 2016 were warmer than normal, indicating that AEY wholesales were progressively reduced during this period by above-normal temperatures.

34. For YEC's GRA forecast purposes, AEY's forecast for the 2017 and 2018 test years was compared to final actual results for 2016 and current year business plans. Based on the above assessment of wholesale changes since 2013, YEC concluded that the 2016 actual results were at least 2 - 3 GW.h below what could be expected based on normal temperatures. YEC submitted that its 2016 Resource Plan forecasts based on normalized weather for non-industrial loads indicated AEY firm wholesales at about 302 GW.h for 2016, 305 GW.h for 2017 and 309 GW.h for 2018, in contrast to much higher estimates (approximately 320 GW.h) from initial runs of the

YEC regression model. Firm wholesale forecasts of 309 GW.h for 2017 and 309.5 GW.h for 2018 were settled on after YEC reviewed its forecasts with representatives from AEY.

35. In response to a Board IR, YEC provided updated wholesale sales of 314.2 GW.h and 314.7 GW.h for 2017 and 2018 respectively, which reflected AEY's approved Compliance Filing forecast.⁴ YEC noted that this information was not available at the time YEC's GRA was filed and that there is no basis to assert that communication issues between YEC and AEY affected the accuracy of the wholesale forecast. YEC noted that the evidence outlined the considerable communication that occurred and that the actual results for 2017 were higher than all relevant forecasts. Therefore, YEC submitted, additional communication would not have resulted in better forecasts for 2017 and 2018.⁵

36. In argument, CW noted that YEC had provided AEY's actual wholesale requirement for 2017, which was 328.4 GW.h. CW submitted that, based on the impact of including AEY's forecast wholesale in the revenue requirement calculation, it would appear that if AEY's actual 2017 wholesale use was included, the decrease in revenue requirement would be even greater than what was highlighted by CW in its evidence. While CW stated its understanding that this application is in a unique position, where the actual usage is available for the entire year of 2017 prior to the forecast test year amounts for 2017 being approved, it referenced the Alberta Utilities Commission, which regularly requires utilities to provide the best information available at the time of the hearing, which is used to assess the reasonableness of the forecasts.⁶ To illustrate, CW used the Alberta Utilities Commission Decision 2012-309, which cited previous decisions such as Decision 2008-113, where the Commission referred to Decision 2006-004, which discussed the use of updated information in a prospective rate setting environment.⁷ CW submitted that the 2017 actuals support a finding that the AEY-approved forecast was more reliable than the YEC forecast filed with this application and that it is closer to the actual for 2017. As a result, CW submitted that YEC be directed to use the 2017 wholesale forecast approved in the AEY compliance filing.⁸

37. In reply, YEC confirmed that the application has been updated to incorporate the wholesale forecast for 2017 as approved in the AEY compliance filing.⁹

Views of the Board

38. The Board is of the view that the information to be used in setting rates should reflect the best information available at the time of the hearing. While the Board understands that YEC determines the wholesale forecast after running its own regression analysis and management's own growth expectations, the Board is of the view that AEY may have more up-to-date information that may more accurately reflect the expected actuals. As a result, the Board directs

⁴ YEC response to YUB-YEC-1-3, PDF page 11.

⁵ YEC final argument, page 18, section 1.1, PDF page 20.

⁶ CW final argument, page 9, paragraph 33, PDF page 10.

⁷ Decision 2012-309: ATCO Gas Errata to Decision 2012-309, 2011-2012 General Rate Application Second Compliance Filing, Compliance Filing to Decision 2012-191, proceeding 2115, November 20, 2012, paragraph 48.

⁸ CW final argument, pages 7-10, paragraphs 27-39, PDF pages 8-11.

⁹ YEC reply argument, page 4, section 2.1.2, PDF page 7.

YEC to use the actual wholesale sales to AEY for 2017 in the amount of 328.4 GW.h. For the 2018 wholesale forecast, the Board observes the difference of 19.4 GW.h between the 2017 actuals and the 2018 forecast. No explanation was provided for this difference. Considering that wholesales were forecast at 309 for 2017 and 309.5 for 2018, the Board is concerned about the reasonableness of the forecast for 2018. Therefore, the Board directs YEC to use the 2018 AEY Compliance amount of 314.7 GW.h for the 2018 forecast.

39. Additionally, several interveners expressed concern regarding the communication between YEC and AEY. While YEC submitted that additional communication would not have resulted in better forecasts for 2017 and 2018, the Board has noted the differences in the forecasts of YEC and AEY. Therefore, the Board directs YEC to refine its methodology to ensure its forecasts align closely with AEY's forecasts in future GRA submissions. Consequently, YEC is directed in its compliance filing to this decision to reflect actual wholesale sales of 328.4 GW.h for 2017 and forecast wholesale sales of 314.7 GW.h. for 2018.

3.2.2 Major industrial sales

40. The test years include one Major Industrial Customer (Minto Mine – Capstone Mining Corp.), with forecast sales of 38.2 GW.h each year. YEC submitted that this forecast reflected updated information provided by Capstone Mining Corp. in the first week of April 2017. YEC also stated it will continue to monitor, with Capstone Mining Corp., any updated forecasts for this mine load during the test years as well as the potential operation of the Minto Mine after 2018.

41. YEC submitted that it continues to monitor additional prospective mine loads. Aside from the potential for the Minto mine to extend or renew its operations, YEC stated it is aware of two other potential near-term mines in the Mayo-Keno region:

- Eagle Gold [Victoria Gold Corp.] – Earliest potential operation would be in late 2018 if development was to commence by summer 2017. In argument, YEC confirmed that the mine is not expected to be operational until after the test years and consequently will have no impact on test year firm sales.¹⁰
- Alexco Mine [Alexco Resources Corp.] – Until plans are finalized and permits are secured, YEC is not able to include any related load forecast.

42. In response to a Board IR, YEC confirmed that it had no status update regarding the Whitehorse Copper Tailings industrial load that was forecast to be supplied by AEY in the 2013 Compliance Filing. YEC stated that the proposed customer has acknowledged via its website that the 2014 drop in ore price made the project unsustainable, and thus no provision has been made in YEC test year's forecasts for this customer.¹¹

43. In response to an undertaking at the hearing, YEC provided an updated 2018 industrial sales forecast for Minto at 32.192 GW.h based on actual January-June sales of 22.361 GW.h and

¹⁰ YEC final argument, page 20, section 1.2, PDF page 22.

¹¹ YEC response to YUB-YEC-1-57 (b), PDF page 218.

a revised forecast for the balance of the year of 9.831 GW.h.¹² YEC explained that more recent information indicated that the mine would significantly constrain operations in the last half of 2018; however, YEC submitted that, based on the principle that GRA cost and sales forecasts are not to be adjusted to reflect subsequent events, it has not sought to adjust its application to address any change in the industrial 2017 and 2018 test year Minto sales forecast.¹³

44. In argument, CW recommended that YEC be directed to develop models that reflect the uncertainty of industrial load requirements in its Resource Plan forecasts and referenced a probabilistic approach.¹⁴ The UCG submitted that utility variability created by transient industrial or larger commercial loads is a significant issue and recommended onsite generation for industrial loads with guaranteed upfront payments.¹⁵

45. In reply, YEC did not agree that either approach was feasible. In regards to the CW approach, YEC stated that individual industrial loads in Yukon have a much greater impact on the overall system load than would be the case in southern jurisdictions, and ongoing planning and forecasting in Yukon must directly address the risks relating to specific loads being on or off the grid. YEC submitted that it must consider the unique circumstances of each potential industrial customer in assessing probable impacts to the system. In regards to the UCG approach, YEC noted that neither YEC nor AEY have any incentive to over forecast sales for GRA purposes, as this overstates expected net returns and that UCG's proposal ignores the utility mandate to provide service and ongoing YUB-specific and positive PPA review recommendations for each new mine connected to the grid since closure of the Faro mine in 1998.¹⁶

Views of the Board

46. The Board is of the view that the most accurate and current information available at the time of the hearing should be used to make a decision on an application. Accordingly, the Board directs YEC to update its major industrial sales forecast in its compliance filing to account for the 2017 actuals and the updated 2018 Minto sales forecasts indicated in the undertaking.

47. Regarding the recommendation of CW that YEC be directed to develop models that reflect the uncertainty of industrial load requirements, the Board agrees with YEC that individual industrial loads in Yukon have a greater impact on the overall system load than is the case in southern jurisdictions. The Board is of the view that each potential industrial customer has unique circumstances, and therefore, each customer must be assessed separately. The Board also does not find it feasible at this time to recommend onsite generation for industrial loads with guaranteed upfront payments as proposed by UCG.

¹² YEC Undertaking 36, PDF page 1.

¹³ YEC final argument, page 20, section 1.2, PDF page 22.

¹⁴ CW final argument, page 7, paragraphs 25, 26, PDF page 8.

¹⁵ UCG final argument, pages 12,13, paragraphs 77-78, 82, PDF pages 13, 14.

¹⁶ YEC reply argument, pages 3, 4, section 2.1.1, PDF pages 6, 7.

3.2.3 YEC firm retail sales

48. YEC firm retail sales are comprised of sales to residential, general service, street light and space light customer classes served directly by YEC. The 2018 forecast of 39.4 GW.h indicates a 3.417 GW.h increase in retail sales over 2013 (actual).

49. Residential retail sales have increased from 13.4 GW.h in 2013 (actual) and are expected to grow to 13.7 GW.h in 2018. This reflects ongoing modest growth in the number of customers offset by a modest decline in the average use by each customer.

50. General service retail sales have increased from 22.3 GW.h in 2013 (actual) and are expected to grow to 25.4 GW.h in 2018. The growth is primarily due to the Faro mine dewatering sales. Street lights and space lights sales are forecast to decrease, primarily due to conversion to LED street lights.

Views of the Board

51. The Board is of the view that the most accurate and current information available at the time of the hearing should be used to make a decision on an application. Accordingly, YEC is directed to update 2017 for the actual firm retail sales. For 2018, the Board accepts the explanations given by YEC and finds that YEC's firm retail sales forecast for 2018 is reasonable.

3.2.4 Secondary sales

52. Due to the surplus hydro generation available after the Alexco mine ceased mining operations in 2013 as well as above-average water conditions, surplus hydro generation has been available for secondary sales. YEC explained that the increase in secondary sales forecast during the test years is due to an increase in customers from one in 2013 to three in 2017 and 2018 and the forecast of ample continuing surplus hydro. The three key secondary customers for 2017 and 2018 are the Canada Games Centre, Whitehorse General Hospital and Yukon College. Based on the secondary sales rate effective January 1, 2017 (based on the YEC's quarterly report to the YUB on November 14, 2016), the wholesale secondary sales rate for this application is \$0.056/kW.h, i.e. \$0.011 kW.h lower than the retail secondary sales rate.

53. In argument, UCG submitted that YEC had not provided enough detailed information to justify the application forecast, especially given that actual secondary sales are 27 percent lower than the application forecast.¹⁷

54. In reply, YEC noted that the application provided the best available information at the time. YEC submitted that by not proposing any change to the application, YEC (and not ratepayers) will bear the total impact of these sales revenues being less than forecast for the test years. YEC explained that, unlike firm sales changes, reductions in secondary sales below forecast do not provide LTA thermal generation cost savings for YEC.¹⁸

¹⁷ UCG final argument, paragraph 91.

¹⁸ YEC reply argument, page 6, section 2.1.4., PDF page 9.

Views of the Board

55. While YEC explained that it, and not ratepayers, will bear the total impact of these sales revenues being less than forecast, the Board is of the view that the most accurate and current information available at the time of the hearing should be used to make a decision on an application. As a result, the Board directs YEC to update the secondary sales forecast in its compliance filing to reflect the 2017 actuals and updated 2018 forecast that YEC indicated it used in its updated revenue requirement in Undertaking 36.

3.2.5 Power generation

56. YEC forecast that hydro generation was to remain the predominant source of generation for the test period albeit hydro was expected to be supplemented by natural gas and diesel thermal generation as required. There is also a small amount of wind generation available on the system. Total generation is based on the sum of total sales plus losses, which are forecast at 8.8 percent for each of the test years. The following table summarizes forecast power generation for the test period:

Table 2. Summary of energy sales and losses and generation (GW.h) 2013-2018

Description	2013 Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Proposed Forecast	2018 Existing Forecast	2018 Proposed Forecast
Sales and Losses								
Total Energy Sales	383,061	388,363	374,248	380,152	385,865	397,859	398,582	398,582
Losses – MWh	33,326	35,127	28,076	37,883	32,186	35,012	35,075	35,075
Losses - %	8.7%	9.0%	7.5%	10.0%	8.3%	8.8%	8.8%	8.8%
Total Generation	416,387	423,490	402,323	418,035	418,051	432,871	433,658	433,658
Secondary Sales Related Generation	0	4,318	5,821	7,731	5,238	12,473	12,473	12,473
Firm Load Generation	416,387	419,172	396,502	410,304	412,812	420,398	421,185	421,185
Source – MWh								
Hydro Generation								
Whitehorse	222,299	221,312	219,243	234,063	232,820	228,084	228,587	228,587
Aishihik	124,475	137,991	112,095	97,330	100,111	121,755	122,024	122,024
Mayo	58,369	62,000	69,082	81,123	78,480	80,280	80,457	80,457
Total Hydro	405,143	421,303	400,421	412,517	411,411	430,119	431,068	431,068
Wind Turbine	238	277	337	650	509	580	580	580
Diesel Generation								
Whitehorse	5,503	840	978	1,672	1,727	577	527	527
Faro	1,651	900	338	405	193	135	123	123
Dawson	3,852	135	223	1,477	938	300	274	274
Mayo	0	34	26	20	22	10	9	9

Total Diesel	11,006	1,910	1,566	3,574	2,879	1,022	934	934
Source - %								
Hydro Generation	97.3%	99.5%	99.5%	98.7%	98.4%	99.4%	99.4%	99.4%
LNG Generation	0.0%	0.0%	0.0%	0.3%	0.8%	0.3%	0.2%	0.2%
Diesel Generation	2.6%	0.5%	0.4%	0.9%	0.7%	0.2%	0.2%	0.2%
Wind Generation	0.1%	0.1%	0.1%	0.2%	0.1%	0.1%	0.1%	0.1%

Source: Application June 2017, Table 2.2, page 2-18. 2017 Actuals not provided for this table in Undertaking #35.

57. YEC forecast generation for the test years, as proposed in Table 2 above, is made up of 99.4 percent hydro in 2017 and 2018, with diesel comprising 0.2 percent of total system generation throughout the test period.

58. YEC submitted that the Yukon Integrated System has 92 MW of installed YEC hydro generation, of which approximately 70.5 MW can be relied upon for the winter peak load. YEC also submitted that the 2013 Compliance Filing and subsequent Board approval of the updated Diesel Contingency Fund have resulted in Yukon Energy's revenue requirement and annual thermal generation costs being determined based on long-term average hydro generation (rather than actual hydro generation resulting from actual water conditions). Accordingly, for the purpose of the 2017 and 2018 test years, hydro and thermal generation forecasts were based on LTA hydro and wind generation as updated with the latest information.

59. YEC added that the predominance of hydro generation on the Yukon system, combined with the fact that Yukon is isolated from other grids outside the territory, creates special seasonal and multi-year conditions that vary with Yukon Integrated System loads. For example, YEC submitted that other forms of backup capacity are required to supplement available hydro to meet the system's winter or spring seasonal generation constraints, to provide reliable energy generation in drought years and to otherwise provide backup generation on the system when hydro is otherwise unavailable (e.g., breakdown/maintenance requirements).

Views of the Board

60. Based on its view that the most accurate and current information available at the time of the hearing should be used to make a decision on an application, the Board directs YEC to update the generation forecast in its compliance filing to reflect the 2017 actuals and updated 2018 forecast that YEC indicated it used in the updated revenue requirement in Undertaking 35 and 36.

3.3 Peak demand forecast and dependable capacity requirement

61. YEC submitted that the peak demand for the Yukon Integrated System is forecast to be 91.8 MW in 2017 and 92.9 MW in 2018, increasing from the actual peak demand of 82.7 MW in 2013, and that in 2016, the grid reached a peak of 88.1 MW. YEC stated that at these forecast peak levels for the test years, thermal generation will be required to supply firm energy demand.

62. YEC further submitted that the 2016 Resource plan has indicated that the existing hydro and diesel infrastructure do not meet the single contingency (N-1) capacity planning criterion in both test years at these forecast grid loads. This results in a forecast dependable capacity shortfall (based on the single contingency [N-1] criterion) of 7.6 MW for 2017 and 8.7 MW for 2018.

63. YEC indicated that it is planning to install 4.4 MW of new LNG generation capacity at Whitehorse in Q1 2019 to partially address this capacity shortfall.

64. In response to a Board IR, YEC clarified that the load and peak demand forecast excluded the contribution of the AEY Fish Lake Hydro, since it is a facility connected to the distribution grid directly serving the local demand in Whitehorse. Adding the dependable capacity of this into the single contingency (N-1) criterion would require an increase in non-industrial loads by the same amount to account for the demand it serves as part of the distribution grid. YEC explained that, considering the added dependable capacity and added demand, the resulting dependable capacity shortfall would be similar to the dependable capacity shortfall calculated for the case without the AEY Fish Lake Hydro contribution. YEC further submitted that this approach is consistent with past assessments of dependable grid capacity provided to the Board.

65. In argument, Mr. Maissan noted that the new record peak load, as acknowledged by YEC in cross examination during the hearing, had occurred on cold days, but not an extreme cold day, and had Whitehorse experienced a day below -40 degrees, the peak may have well been greater. Mr. Maissan concluded that peak loads are likely to grow significantly in coming years due to the installation of electric heat in new construction coupled with the economic up-turn in Yukon's economy and recommended that the Board encourage YEC to communicate closely with AEY and other parties to forecast as accurately as possible and to focus on Capacity DSM as well as capacity and energy-based resource options to meet the increasing peak loads and the new mining energy requirements.¹⁹

Views of the Board

66. Based on the above, the Board is of the view that peak loads are likely to grow in coming years. As a result, the Board encourages YEC to communicate closely with all parties (for example, customers, developers, mining operations) to forecast as accurately as possible to meet increased peak loads and new mining energy requirements.

4 Revenue requirement

4.1 GRA forecasts – Long-term average versus short-term

67. YEC stated that its annual thermal generation expense for revenue requirement purposes is determined based on long-term average hydro generation, rather than actual hydro generation resulting from actual water conditions. Total thermal generation expense for each year is determined at year-end based on the LTA thermal generation requirement for that level of actual firm generation as determined by the rules established in the DCF Term Sheet as approved by the

¹⁹ Mr. Maissan final argument, section 2, PDF page 2.

Board. The LTA estimate for any specific level of firm generation is determined by reference to the relevant table in the approved DCF Term Sheet.²⁰

68. With respect to short-term (ST) versus long-term average (LTA) forecasts of hydro generation for GRA purposes, YEC stated that it supplies grid energy requirements primarily using hydro generation, with thermal generation relied on when hydro is unable to supply all requirements. Forecast thermal generation in any year depends on both the grid loads and the available water. It also stated that, aside from seasonal variability in loads and water supplies, water availability has been shown to vary a great deal over different years – with related major impacts on thermal generation requirements in each year. It submitted that:

- Short-term thermal generation (i.e. over 1 or 2 years) has varied materially due to changes in actual water conditions, resulting in actual thermal generation varying materially from short-term thermal forecasts.
- Long-term average (LTA) hydro generation forecasts have been developed, based on available annual water records as well as current grid conditions and generation facilities, to indicate ongoing average hydro generation capability over hydro asset lives.

69. YEC argued that a distinctive feature of the isolated Yukon grid is its degree of cost vulnerability to drought conditions. As such,

- YEC's forecast LTA fuel cost for 2017 at GRA price assumptions ranges from \$2.2 million (GRA forecast) to \$4.3 million (actual per 2017 DCF Annual Report).
- Using the same load and price assumptions, the added fuel costs above the LTA adopted for the GRA are forecast at \$17.0 to \$18.5 million for the year of lowest recorded water and \$40 to \$45 million for the worst six consecutive years of low water.
- The cost impact of the worst drought year alone (with 2017 loads) equals a rate increase exceeding 20%, or an amount equal to about 15% of YEC's equity – indicating a relatively high degree of cost vulnerability to drought conditions.²¹ (footnotes removed)

70. YEC further stated that:

These key provisions related to water risk assignment and long-term rate smoothing reflect normal principles for rate setting for hydro generation utilities in Canada as well as YEC filings and Board decisions on GRA-related matters for Yukon Energy since 1989.²² (footnotes removed)

²⁰ YEC application, page 3.4-1, Appendix 3.4, section 1.1, PDF page 100.

²¹ YEC final argument, page 7, PDF page 9.

²² YEC final argument, page 8, PDF page 10.

71. YEC added that:

Yukon Energy emphasized that discontinuing a DCF based on forecast LTA water conditions for the 2017 period forward and instead relying on ST water condition forecasts and a related ST contingency fund mechanism (that would need to be developed) would:

- Increase rate instability;
- Mask, rather than display, the expected long-term cost of power; and
- Frustrate, rather than facilitate, intergenerational equity and fair treatment related to the benefits provided by hydro generation over its long-term economic life.²³
(footnotes removed)

72. YEC provided examples of its asserted potential volatility of ST hydro and thermal generation forecasts in its argument.²⁴

73. The UCG disagreed with YEC's position that it had justified the continued use of LTA versus the ST hydro generation forecast. UCG argued that YEC has not mentioned in its arguments that the forecast revenue shortfalls would be reduced by \$2.03 million and \$0.7 million in 2017 and 2018²⁵ respectively as a result of using the ST hydro generation forecast. In its argument, UCG submitted that the Board should use the ST hydro generation forecast for the 2017 and 2018 test years and going forward within a performance or incentive-based regulatory regime.²⁶ Further, UCG submitted that it is important that rate signals be sent to customers in a timely fashion to allow them to respond to changes in rates.²⁷

74. YEC responded that UCG's argument for price signals ignores the evidence presented by YEC that it is inappropriate to send price signals to ratepayers when the time horizon is too short for meaningful action by the ratepayer, as generally happens in the event of a drought.²⁸ YEC argued that UCG arguments on COS and other rate-related matters are without merit, as the introduction of new untested evidence on performance-based or incentive regulation mechanisms is beyond the scope of this proceeding.²⁹

Views of the Board

75. The Board recognizes that historically YEC has generally used LTA for its hydro generation and thermal generation forecast. However, in this proceeding, the question of whether a ST forecast should be used for the hydro generation and thermal forecast has been raised. To address this issue, the Board returns to first principles. The mandate of the Board is to determine just and reasonable rates that are in the public interest. In setting just and reasonable rates, the Board determines the level of costs a utility can recover for providing a specified level of service over a specific time period. The Board uses the best available information when making its

²³ YEC final argument, pages 11-12, PDF pages 13, 14.

²⁴ YEC final argument, page 12, PDF page 14.

²⁵ UCG final argument, page 19, paragraph 123, PDF page 20.

²⁶ UCG reply argument, page 12, paragraph 52, PDF page 13.

²⁷ UCG final argument, page 9, paragraph 52, PDF page 10.

²⁸ YEC reply argument, page 19, PDF page 22.

²⁹ YEC reply argument, page 24, PDF page 27.

determinations. A GRA should include accurate forecasts for the test years and provide a comparison of actual results to decision amounts in previous periods in order to test the reasonableness of the forecast and forecasting accuracy. The forecast should be most representative of the GRA test years.

76. The Board recognizes that each method of forecasting, being LTA or ST, has advantages and disadvantages for GRA purposes. As submitted by YEC, during a period of favorable water conditions an ST hydro generation forecast would have a lower revenue requirement than one based on an LTA hydro generation forecast. The converse holds for periods when water conditions are unfavorable. With ST hydro generation forecasts, the impacts on revenue requirements, rate changes and resulting bills will change with each GRA depending on changes in ST water conditions and forecasts. LTA hydro generation forecasts will tend to be more stable for revenue requirements from GRA to GRA. However, items affected by this forecast may not be as accurate or representative of current GRA circumstances. For the current GRA, major differences in ratepayer bill impacts with ST versus LTA hydro generation forecasts are likely to be limited if the current rate stabilization mechanism is retained.³⁰ The Board accepts that short-term thermal generation may vary materially between GRAs due to changes in actual water conditions. LTA hydro generation forecasts are based on available historic annual water records as well as current grid conditions and generation facilities to indicate ongoing average hydro generation capability over a longer period of the hydro asset life.

77. Given the above-noted advantages and disadvantages of LTA and ST hydro generation forecasts, the Board finds that, for purposes of this proceeding, it will not use the ST forecast for forecasting levels of hydro electric generation and thermal generation nor direct its use for future GRAs. In determining the revenue requirements for these and future test years, the Board is focusing on the reasonableness of the forecasts and forecasting accuracy. Further, the onus is on YEC to adequately explain any variance between actual results and its forecast amounts. For these reasons, the Board directs YEC in future GRA filings to show actual hydro and thermal generation results when comparing previous and forecast test years.

4.2 Overview

78. There are three major components to YEC's revenue requirement:

- Operating and maintenance expenses, including fuel costs, labour and costs for administering the utility
- Depreciation and amortization of assets and deferred costs included in rate base
- Return on rate base to cover the costs of YEC's various sources of capital (long-term debt issuances and equity) required to finance the rate base

79. YEC stated that the forecast 2017 and 2018 revenue requirements primarily resulted from the proposed adjustments to diesel generation requirements and fuel prices, changes to labour

³⁰ ERA Two-Part Filing, Parts 1 and 2, pages 2-11 to 2-12, PDF pages 39-40.

and non-labour costs, increases in rate base, as well as changes in the proposed return on equity (ROE) relative to the 2013 GRA-approved forecast (“2013 approved”) numbers.³¹

Table 3. Yukon Energy Revenue Requirement (\$000)

	2013 Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Forecast	2018 Forecast
Fuel and purchased power	3,200	3,878	1,569	2,756	2,159	2,381	2,407
Non-fuel operating and maintenance	18,111	19,381	19,957	19,580	20,470	22,060	22,016
Depreciation and amortization	8,604	9,500	7,783	8,690	7,816	10,814	11,094
Return on rate base	12,348	11,139	11,938	10,829	12,242	13,289	14,348
Total revenue requirement	42,263	43,897	41,247	41,855	42,686	48,544	49,864

Source: Application June 2017, Table 3.1, PDF page 50.

4.3 Use of 2017 actual results

80. During questioning at the oral hearing, the Board requested YEC to update its Tab 7 - GRA schedules (Tab 7) to include actual results for the year 2017 given that the hearing was held in June 2018. The reason for the request was to have on the record of the proceeding the most accurate and up-to-date information on which to make determinations regarding YEC’s 2017-2018 revenue requirement. YEC undertook to provide this information.

81. YEC filed the requested update in Undertaking 35 on July 20, 2018. The results showed that overall, compared to YEC’s 2017 proposed forecast, actual 2017 revenue requirement increased by a total of \$3.539 million. The largest increase was in the category of fuel and purchased power costs by an amount of \$2.086 million. Operating and maintenance (O&M) costs had a net increase within various O&M categories in the amount of \$0.418 million. YEC explained that the O&M increases reflected “higher production costs related mainly to the mobile diesel lease, higher transmission and distribution costs, higher general cost, and lower administration and general costs reflecting mainly lower labour costs due to unfilled positions.”³² Also contributing to the increase in revenue requirement was an increase in return on rate base in the amount of \$0.812 million, due largely to the actual 2017 long-term debt cost of 2.58 percent being higher than the 2.18 long-term percent assumed in the 2017 forecast.

82. YEC argued that it continued to rely on the test year forecasts as filed in June 2017 except for the update required to incorporate the wholesale forecasts for 2017 as approved by Board Order 2017-01.

83. With respect to the use of 2017 actual results, YEC stated that:

Regulatory principles and precedents from past GRAs reviewed by the Board highlight the importance of assessing reasonable load and cost forecasts for each test year from the timing perspective of the initial GRA filing. Utility acceptance of forecast risk is reasonable in this context, and parties avoid the range of issues that emerge when actual results beyond that time period begin to be considered.

³¹ YEC application, page 3-2, section 3.1, PDF page 50.

³² YEC response to Undertaking 35, PDF page 4.

...

The Application's proposed 2017 and 2018 revenue requirements reflect the reasonable costs required for Yukon Energy to supply customers in 2017 and 2018 and to plan for future requirements thereafter. The proposed rate adjustments are required to recover the forecast revenue shortfalls related to the proposed revenue requirements. The updated DCF and planning cost accounting policy as proposed are required to enhance customer rate stability.³³

84. CW submitted that YEC, in its compliance filing, should be directed to use the 2017 wholesale forecast approved in the AEY compliance filing in the amount of 314.2 GW.h. Based on YEC's rebuttal evidence, it appeared to CW that YEC was prepared to incorporate AEY's approved wholesale forecast in its compliance filing.

85. In its reply argument, YEC noted that CW was the only intervener to address the use of forecasts as filed versus more recent updates and actuals. Other than CW's submission that "2017 actuals support a finding that the AEY approved wholesale forecast is more reliable than the YEC forecasts filed with the application,"³⁴ YEC stated that CW did not argue that 2017 actual results should be adopted.

Table 4. Yukon Energy Revenue Requirement (\$000)

	2013 Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2017 Forecast	2018 Forecast
Fuel and purchased power	3,200	3,878	1,569	2,756	2,159	4,493	2,381	2,407
Non-fuel operating and maintenance	18,111	19,381	19,957	19,580	20,470	22,476	22,060	22,016
Depreciation and amortization	8,604	9,500	7,783	8,690	7,816	11,013	10,814	11,094
Return on rate base	12,348	11,139	11,938	10,829	12,242	14,101	13,289	14,348
Total revenue requirement	42,263	43,897	41,247	41,855	42,686	52,083	48,544	49,864

Source: YEC Application June 2017, Table 3.1, PDF page 50, and Undertaking 35, Tab 7 - schedules 5 and 10 for 2017 Actual.

Views of the Board

86. The Board expects to receive the most up-to-date information during a proceeding and for utilities to bring evidence of increasing or decreasing costs during a proceeding as it becomes available. The Board is of the view that the 2017 actuals filed as Undertaking 35 provide the most up-to-date information available during this proceeding, thus ensuring that the Board has the best possible information before it in order to make a decision on the application. This is the practical consequence of having a proceeding that runs into the 2017-2018 test years. Although YEC has argued that it bears forecast risk and is relying on the test year forecasts as filed in June 2017, except for the update required to incorporate the wholesale forecasts for 2017 as approved by Board Order 2017-01, the Board is of the view that once it is apprised of more up-to-date information, it may use the updated information when assessing the reasonableness of the various items that comprise the revenue requirement. Therefore, the Board will rely on the 2017

³³ YEC final argument, pages 14, 15, PDF pages 16, 17.

³⁴ YEC reply argument, page 2, PDF page 5.

actual results in its determination of YEC's 2017-2018 revenue requirement. However, the Board observes that the detail provided in Undertaking 35 was generally not at a level sufficient to make wholesale approvals of all cost components without a further examination of key variances.

87. For this reason, in the sections which follow where the Board has been able to glean enough information from Undertaking 35 to make an Order with respect to a line item or cost component of revenue requirement, it will do so. However, where the Board requires further information in order to render a final decision, YEC will be required to supply the information in its compliance filing to this Order. This approach will apply equally to each line item or cost components of YEC revenue requirements including specific capital project considerations and customer, energy sales and revenue information, which likewise inform specific components of revenue requirement.

88. The Board finds that proceeding in this manner will afford parties with the opportunity to examine any variances between 2016 and 2017 actual results, as well as variances between 2017 actual and forecast results in the compliance filing while still maintaining the ability of the Board to rely on the best available information at the time it renders its decision. To that end, where the discussion contained in subsequent sections of this decision has observed measurable variances between 2016 and 2017 actual results, or variances between 2017 actual and forecast results, YEC is directed to provide the applicable variance explanations in its compliance filing to this decision.

4.4 Fuel and purchased power

89. Fuel and purchase power costs were discussed on pages 3.3 – 3.5 of the application. In Table 3.2 of the application, YEC forecasts Fuel and Purchase Power costs of \$2.381 million and \$2.407 million for each of 2017 and 2018. These forecast amounts include fuel for thermal maintenance activities. This forecast was based on long-term average (LTA) hydro and wind generation resulting in LTA thermal generation. The LTA thermal generation requirements were assumed to be supplied from a thermal generation mix consisting of 90 percent LNG and 10 percent diesel generation. YEC noted that the Diesel Contingency Fund (DCF) addresses any variance between actual thermal generation and LTA requirements for actual firm load generation. Rider F addresses any variances in diesel or LNG delivered fuel prices from prices in the GRA forecast. Table 3.2 of the application provided a history of actual and forecast costs for the period of 2013-2018 inclusive. The forecast for LTA thermal generation in 2017 and 2018 is 14.1 GW.h and 14.5 GW.h respectively. YEC's initial forecast for fuel and purchased power is illustrated in Table 2 below:

Table 5. Fuel and purchased power (\$000)

	2013 Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Forecast	2018 Forecast
Fuel	3,160	3,848	1,528	2,720	2,114	2,190	2,368
Purchased power	40	30	41	36	45	39	39
Total fuel and purchased power	3,200	3,878	1,569	2,756	2,159	2,381	2,407

Source: Application June 2017, Table 3.2, PDF page 52.

90. YEC forecast the delivered price for LNG to be \$0.3767/litre, with an average generation efficiency of 2.57 kW.h/litre giving a resulting forecast LNG cost of \$0.1467/kW.h.

91. Similarly, YEC provided the following forecasts with respect to diesel fuel:

Table 6. Diesel assumptions

Location	Fuel Price/litre	Efficiency (kW.h/litre)
Whitehorse	\$0.9163	3.60
Faro	\$0.9535	3.67
Dawson	\$0.9818	3.49
Mayo	\$0.9616	3.46

92. The overall grid efficiency used for this application is 3.58 kW.h/litre and the average cost per kW.h of diesel for this application is \$0.2633/kW.h.

93. YEC forecast power purchased from AEY at the Johnson's crossing location. The forecast for both test years is \$0.039 million.

94. In YEC's alternative GRA forecast (based on short-term (ST) hydro generation forecasts for each of the test years), fuel costs are forecast at \$0.360 million and \$1.705 million for each of 2017 and 2018 respectively.

95. The following tables compare the two forecasts:

Table 7. Comparison of LTA and ST forecasts for fuel costs

	LTA	LTA	ST	ST
	2017	2018	2017	2018
Fuel Costs (\$millions)	2.381	2.407	0.360	1.705
Thermal Fuel Mix (% - LNG:Diesel)	90:10	90:10	60:40	60:40
Generation (GW.h)	14.1	14.5	1.1	8.2

Table 8. Comparison of LNG and diesel assumptions

	LTA	ST
Delivered Price – LNG (per litre)	0.3767	0.3767
LNG Efficiency (kW.h/litre)	2.57	2.57
LNG Cost (per kW.h)	0.1467	0.1467
Diesel Price – Whitehorse (per litre)	0.9163	0.9163
Diesel Price – Faro (per litre)	0.9535	0.9535
Diesel Price – Dawson (per litre)	0.9818	0.9818
Diesel Price – Mayo (per litre)	0.9616	0.9616
Efficiency kW.h/litre – Whitehorse	3.60	3.60
Efficiency kW.h/litre – Faro	3.67	3.67
Efficiency kW.h/litre – Dawson	3.49	3.49
Efficiency kW.h/litre – Mayo	3.46	3.46
Overall Diesel Grid Efficiency (kW.h/litre)	3.58	3.58
Overall Diesel Costs (\$/KW.h)	0.2633	0.2633

96. Purchase power costs remain unchanged between the two forecasts at \$0.039 million for each of the test years.

LNG: Diesel ratio

97. In response to YUB-YEC-1-25 (a), YEC stated that the LNG ratio was not statistically based, but reflected experience and expectations related to thermal generation to supply LTA requirements over all water years.

98. In response to the (c) part of that IR, YEC noted that actual fuel mixes for 2015 and 2016 were (including capital and RFID):

2015 – 27:73 LNG/Diesel

2016 – 53:47 LNG/Diesel

99. In response to Undertaking 35, YEC provided the following update for 2017 fuel and purchased power costs:

Table 9. Fuel and purchased power (\$000)

	2013 Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2017 Actual (ST)	Existing 2017 Forecast	Proposed 2017 Forecast
Fuel	3,160	3,848	1,528	2,720	2,114	4,444	1,076	2,175	2,342
Purchased power	40	30	41	36	45	49	49	39	39
Total fuel and purchased power	3,200	3,878	1,569	2,756	2,159	4,493	1,125	2,214	2,381

Source: Undertaking 35, Schedule 10, PDF page 19.

Views of the Board

100. As earlier stated in paragraphs 87-89, the Board is relying on 2017 actual results for the 2017 test year. However, the 2017 thermal generation amounts must be based on actual thermal generation fuel costs, not modelled results. Thermal generation fuel costs will be based on actual thermal generation output for the year and the costs required to produce that output. It is unclear if the fuel costs in Table 3 above represent actual costs or modelled costs. Therefore, YEC is directed in its compliance filing to this decision to reflect actual fuel costs for 2017. For the 2018 test period, YEC is to use the fuel costs related to YEC's forecast for 2018.

101. The Board has reviewed the thermal assumptions provided by YEC and has determined them to be reasonable. Therefore, the Board accepts the cost and efficiency parameters (thermal assumptions) as submitted by YEC.

102. In terms of the fuel mix, several different fuel mixes have been presented to the Board for the 2018 forecast. Consequently, the Board directs YEC, in its compliance filing, to state which fuel mix it is using for its 2018 forecast.

4.5 Non-fuel operating and maintenance expenses

103. YEC requested approval to include in revenue requirement, non-fuel operating and maintenance (O&M) expenses forecast to be \$22.060 million and \$22.016 million in the years 2017 and 2018, respectively. This represented a forecast \$3.949 million increase in 2017 from 2013 approved O&M expenses and a forecast \$0.410 million decrease in 2017 from 2016 actual O&M expenses. YEC forecast a further \$0.044 million decrease in the year 2018 from 2017 forecast O&M expenses.

104. In Undertaking 35, YEC updated its Tab 7 - GRA schedules (Tab 7) to include actual results for the year 2017. Actual 2017 results provided in Undertaking 35 indicated an increase of \$2.006 million in total non-fuel O&M expense from 2016 Actual and an increase from 2017 forecast in the amount of \$0.416 million. However, detail of the costs by category was not provided in Undertaking 35 as demonstrated in the following table:

Table 10. Non-Fuel Operating and Maintenance expenses (\$000)

	2013 Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2017 Forecast	2018 Forecast
Labour	9,348	10,604	11,172	11,068	11,739	21,763	11,770	11,823
Production	1,437	1,639	1,795	1,595	1,906		1,750	1,799
Transmission	853	1,266	594	680	709		1,417	1,419
Distribution	226	322	553	541	284		530	535
General O&M	1,154	1,224	1,321	1,382	1,156		1,238	1,219
Administration	3,646	2,778	2,947	2,585	2,726		3,149	3,001
Insurance and reserve for injuries/damages	1,121	1,216	1,243	1,256	1,263	693	1,510	1,510
Property taxes	326	331	331	473	686		696	708
Total non-fuel O&M expenses	18,111	19,381	19,957	19,580	20,470	22,476	22,060	22,016

Source: YEC Application June 2017, Table 3.3, PDF page 53, and Undertaking 35, Tab 7 - Schedule 10 for 2017 Actual.

105. In its argument, UCG made a number of assertions³⁵ with respect to the veracity of YEC's forecast O&M expenses, including UCG concerns with respect to the level of detail supporting overall O&M expense increases both during and beyond the period of 2013-2016, a lack of operating cost control measures, difficulty with the comparability of the GRA application and draft financial statements, and concerns with the appropriateness of YEC's overhead capitalization policy. The UCG also claimed that, due to YEC filing its GRA in June of 2017 as opposed to earlier in the year, ratepayers were prejudiced. Consequently, UCG submitted that "once a 2017 revenue requirement is determined, YEC should, at a maximum, only be allowed recovery of revenue that was realized through application of existing base rates and the interim rate rider during 2017.... [because]... making new rates effective January 1, 2017 would constitute a form of rate retroactivity that would be an unreasonable burden on Yukon ratepayers who could not know the cost of their electricity use decisions prior to the YUB making a final decision on this application. UCG submits that this would be a strong message by the YUB that

³⁵ UCG final argument, pages 6, 8, 26, 27, paragraphs 25, 43, 44 and 173-183, PDF pages 7, 9 and 27, 28.

rate applications submitted mid-way through a test year will no longer be accepted as the norm.”³⁶

106. With respect to O&M costs, UCG suggested that, rather than just cutting costs, YEC should be directed to look at “doing more with the same amount of money or doing the same with less”³⁷ which could be enabled through some method of performance-based (or incentive-based) ratemaking.

107. UCG summarized its position, stating that “[g]iven the fact the YEC sets its proposed operations and maintenance budgets based on a historical review, UCG submits that the YUB should direct YEC to reduce O&M costs per customer by 10% in each of the test years and establish a clear plan of action that will reduce these escalating costs.”³⁸

108. YEC argued that the UCG recommendation for a 10 percent reduction in O&M costs was arbitrary and without merit. YEC cited UCG as consistently misunderstanding the nature of the Board’s approval of test years’ forecasts and submitted that the YUB “approves a revenue requirement for the sole purpose of setting adjusted rates to be charged to ratepayers” and when “actual costs exceed YUB-approved forecasts, YEC’s return to its shareholder is reduced.”³⁹

109. YEC added that UCG’s “wide range of assertions and recommendations [are] beyond the scope of the Application” which included the “provision of new evidence on certain matters, and criticism of the application and other on a range of matters.”⁴⁰ YEC argued that its application was filed and must be assessed in accordance with the *Public Utilities Act*; that YEC is not incented to delay its GRA filings; and finally, that the Board would have no basis to penalize YEC or any other utility for the timing of its GRA filings.

Views of the Board

110. The Board, in this section, will consider the arguments of UCG which recommended a 10 per cent reduction in O&M costs for the years 2017-2018 and a further recommendation that YEC only be allowed recovery of revenue that was realized through the application of existing base rates and the interim rate rider during 2017.

111. Given that UCG did not file evidence in this proceeding supporting its recommended 10 percent reduction in O&M costs, the Boards finds that there are no grounds for implementing such a measure as a means to reduce what UCG has asserted are escalating costs. For this reason, the UCG recommendation for a 10 percent reduction in O&M costs for the years 2017-2018 is denied.

112. With respect to UCG’s assertion of ratepayers being disadvantaged by YEC filing its GRA application in mid-2017 as opposed to earlier in the year, the Board also finds there to be

³⁶ UCG final argument, page 10, paragraph 59, PDF page 11.

³⁷ UCG final argument, page 26, paragraph 179, PDF page 27.

³⁸ UCG final argument, page 27, paragraph 182, PDF page 28.

³⁹ YEC reply argument, page 9, PDF page 12.

⁴⁰ YEC reply argument, page 2, PDF page 5.

no evidence before the Board in support of such an assertion. In addition, Section 29 of the *Public Utilities Act* states, in part:

29 In setting rates that a public utility is permitted to charge,

(a) the board may consider the revenues and costs of the public utility in **the financial year in which the proceedings for setting the rates and charges began** or in any period immediately following, without considering the allocation of those revenues and costs to any part of that period;

(b) the board may give effect to that part of any excess of revenue received or deficiency incurred that is in the opinion of the board applicable to the **whole of the financial year of the public utility in which the proceeding was initiated as the board considers just and reasonable**; (emphasis added)

113. Accordingly, the Board may allow a utility to recover revenue and costs for the year in which an application is filed. As the *Public Utilities Act* allows the Board to consider an application filed during a test year, the Board is of the view that no direction as to the timing of the filing of a general rate application is needed. For these reasons, the UCG recommendation to allow only the recovery of revenue that was realized through application of existing base rates and the interim rate rider during 2017 is denied.

114. In the sections which follow, the Board will address parties' concerns with specific aspects of YEC's O&M expenses.

4.5.1 Labour

115. YEC's 2017 forecast labour expense increased by \$3.949 million from 2013 approved labour costs and a \$0.310 million decrease in 2017 from 2016 actual labour costs. YEC forecast a further \$0.044 decrease in the year 2018 from 2017 forecast labour expense.

116. YEC summarized its position that "[t]he increase in 2017 and 2018 forecast labour expense compared to 2013 approved costs reflects additional positions, as well as increased labour rates and changes in the capital/maintenance allocation."⁴¹

117. YEC's full-time equivalent (FTE) level was forecast to increase by 1.70 FTEs in 2017 over 2013 approved FTEs and increase by 0.39 FTE in 2017 from 2016 actual FTEs. YEC stated that it has had minimal growth in its labour complement by filling only necessary positions. Further, YEC forecast there would be no change in its overall 2018 FTE requirement from that forecast for 2017 and therefore would remain static for both years at 93.70 FTEs.

118. Notwithstanding that YEC's Actual 2017 results provided in Undertaking 35 did not provide detail for 2017 actual FTE results, YEC's FTE employee complement for the years 2013-2018 is provided in the following table:

⁴¹ YEC final argument, page 23, section 2.2, PDF page 25.

Table 11. Employee Complement History (FTEs)

	2013 Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2017 Forecast	2018 Forecast
President	4.50	5.00	5.00	5.46	5.09	detail not provided	5.16	4.16
Communications	1.00	1.00	1.00	1.00	1.00		1.00	1.00
Human resources & information management	6.25	6.16	6.12	6.13	5.2		5.25	5.25
Resource planning and environment	7.00	7.00	6.00	6.00	6.00		5.00	5.00
Finance, customer accounting and purchasing	14.00	16.96	17.63	16.81	16.87		16.79	16.79
Operations	41.25	42.83	42.15	42.79	44.15		43.50	44.50
Engineering services	13.00	12.00	13.00	13.00	13.00		15.00	15.00
Health, safety & environment	2.00	2.00	2.00	2.00	2.00		2.00	2.00
Total employee complement	92.00	92.95	92.90	93.19	93.31		93.70	93.70

Source: YEC Application June 2017, Table 3, PDF page 5. Employee complement numbers are net of allocation to YDC and Undertaking 35, Tab 7 - Schedule 10 for 2017 Actual.

119. During the hearing, YEC was questioned on the status of its compliance with paragraph 84 from Board Order 2013-01, which stated that YEC was to “demonstrate in its next GRA [2017-2018] that the complement levels approved in this GRA [2012-2013] will have effectively reduced the costs or use of outside consultants.”⁴²

120. In Undertaking 27, YEC confirmed that the complement level of 90 FTEs approved in Board Order 2013-01 for the years 2013-2016 resulted in YEC being able to access internal staff for activities that would have otherwise likely been assigned to external consultants going forward. YEC prepared information showing that over the period of 2013-2017, actual outside consulting costs for capital, administration and operations decreased by approximately \$6.5 million for each year compared to the period of 2009-2012.⁴³

121. Average annual negotiated wage increases influencing the general year-over-year labour increases were approximately 1.9 per cent between the years 2013 to 2016. As a result of an ongoing collective bargaining process, specific rate increases could not be provided; therefore, provisions in the GRA for overall wage increases were forecast to be 2.0 per cent for the year 2017 and 1.75 per cent for the year 2018.⁴⁴

122. No issues were raised by interveners with respect to forecast test year amounts related specifically to labour costs or the associated FTE count.

123. Also contributing to the overall increase in labour costs from 2013 approved to 2017-2018 forecast amounts was a proposed change to the capital/maintenance allocations applied to

⁴² Board Order 2013-01, Appendix A: Reasons for Decision, March 25, 2013, page 20, paragraph 84, PDF page 21.

⁴³ YEC Undertakings, July 13, 2018, Undertaking 27, PDF pages 27-29.

⁴⁴ YEC Undertakings, July 13, 2018, PDF page 4: Transcript Errata, Volume 3, June 28, 2018, page 540, lines 2-5.

each FTE position. YEC explained that the “allocation directly impacts the revenue requirement in any given year as maintenance charges are directly expensed while capital labour is reflected in expenses such as depreciation after the project is completed and placed into service.”

124. The 2013 allocation between capital and maintenance was approved at an overall ratio of 23:77 (capital to maintenance), whereas the allocation for the 2017-2018 forecast was adjusted to align with historical results which supported a ratio of 18:82 (capital to maintenance).

125. In another matter related to labour costs, CW asserted that there was no place within YEC’s application to understand total labour and cost per FTE. CW recommended that, similar to the presentation of the information that is done in other jurisdictions,⁴⁵ the Board should establish a minimum filing requirement for labour cost information so as to facilitate more efficient testing by all parties, including the Board.⁴⁶

126. The UCG agreed with CW that there is a need for minimum filing requirements; however, UCG recommended the requirement should be applicable for all types of information and not just data related to labour. Furthermore, UCG argued that minimum filing requirements should be established in Yukon related to the various types of applications to the YUB.⁴⁷

127. In response to the CW request for minimum filing requirements for labour costs, YEC, in its rebuttal evidence, outlined the types of total labour and cost per FTE information provided in its application. YEC also stated that, while it has the ability to report on additional breakouts of labour such as fringe, contract and other costs, it did not use the other categories identified in CW evidence.

Views of the Board

128. The Board is satisfied that YEC has demonstrated compliance with paragraph 84 of Board Order 2013-01 in Undertaking 27, specifically that YEC has reduced its reliance on consultants as a result of the FTEs approved in the prior GRA.

129. With respect to FTEs, notwithstanding that the table above (Table 11) illustrates that there have been minimal FTE increases forecast between 2016 actual and 2017 forecast, the Board considers that it requires actual 2017 FTE information in order to make a final determination on FTEs. YEC is directed to provide this information by way of updating the information found in Table 8 for 2017 actual FTE results.

130. Further, the Board agrees in principle with YEC’s proposed update to its capital-to-maintenance allocation to a ratio of 18:82 based on recent trends. However, the Board directs this ratio be determined based on the inclusion of 2017 actual capital-to-maintenance results and for YEC to provide the updated 2017 ratio and, further, to clarify whether, based on this updated

⁴⁵ Evidence of the City of Whitehorse, page 13, PDF page 14.

⁴⁶ CW final argument, page 16, paragraph 57, PDF page 17.

⁴⁷ UCG final argument, page 4, paragraph 8, PDF page 5.

ratio, a change from its proposed 18:82 capital-to-maintenance ratio is required for the year 2018 in its compliance filing to this Order.

131. With respect to the labour escalation per cents relied on for labour-cost forecasting purposes in the amounts of 2.0 per cent and 1.75 per cent for the years 2017 and 2018 respectively, the Board directs YEC to provide 2017 actual labour escalation amounts for information purposes in its compliance filing to this Order.

132. Where the directions contained in this order result in measurable FTE variances between 2017 actual results and 2016 actual or 2017 forecast results, YEC is directed to provide the applicable variance explanations in its compliance filing to this decision.

133. Finally, concerning the CW's request for a more complete picture of YEC's total labour costs and FTE count, the Board agrees it would be helpful to have this supplementary labour information available in a central location from the outset of YEC's application. The Board directs YEC in its next GRA to complete the labour schedule identified by CW in its evidence in as much detail (for both cost and FTE) as is applicable to YEC and to submit the information as an additional schedule within YEC's existing Tab 7 format.

134. The Board does not agree with UCG that it is reasonable to establish minimum filing requirements in Yukon within the context of a single utility's GRA application, and for this reason, the UCG recommendation is denied.

4.5.2 Production

135. YEC's total production costs in 2017 are forecast to increase by \$1.266 million over 2013 approved costs and by an additional \$0.147 million in 2018 over the 2017 forecast. YEC stated that approximately 72 percent (or \$1.052 million) of the increases in the 2018 forecast compared to 2013 approved is due to higher labour costs.

136. Comparing 2016 actual results with 2017 forecast amounts, YEC is anticipating production cost reductions in the amount of \$0.279 million. The decrease in costs is due to the change in the capital-to-maintenance labour allocation in 2017 and a reduction in heating fuel costs.

137. Comparing 2017 and 2018 forecast amounts, YEC anticipated an increase in labour charges of approximately \$0.100 million, which reflected an additional maintenance mechanic in 2018.⁴⁸

138. Actual 2017 results provided in Undertaking 35 indicated an increase of \$0.351 million in total production costs from the 2016 actual and an increase from the 2017 forecast in the amount of \$0.630 million. YEC indicated that higher production costs related mainly to the mobile diesel lease. However, detail of the costs by production cost line-item category was not provided in Undertaking 35, as demonstrated in the following table:

⁴⁸ YEC response to YUB-YEC-1-9, PDF page 29.

Table 12. Production Costs (\$000)

	2013 Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2017 Forecast	2018 Forecast
Labour	3,057	3,671	3,792	3,876	4,133	detail not provided	4,010	4,109
Diesel	439	444	569	430	548		436	425
LNG	-	-	-	61	224		155	196
Hydro	909	1,024	1,107	1,024	1,058		1,075	1,093
Wind	18	17	43	3	14		6	6
Operation supervision	72	154	77	78	62		77	79
Total production costs	4,494	5,310	5,588	5,472	6,039	6,390	5,760	5,907

Source: YEC Application June 2017, Table 3.5, PDF page 56, and Undertaking 35, Tab 7 - Schedule 10 for 2017 Actual.

139. No issues were raised by interveners with respect to forecast test year amounts related specifically to production costs.

Views of the Board

140. Based on the evidence and variance explanations provided therein, the Board is prepared to accept both YEC's 2017 actual results and the 2018 forecast. However, in the compliance filing to this decision, YEC is directed to update the information found in Table 12 for 2017 actual production costs by cost category.

4.5.3 Transmission, Distribution and Brushing Costs, including the Vegetation Management Deferral Account

141. Within the following four sub-sections, the Board addresses O&M costs related to YEC's transmission and distribution functions including specific costs pertaining to brushing activities and the deferral of vegetation management costs.

142. Views of the board with respect to these four subsections can be found commencing at paragraph 161.

4.5.3.1 Transmission

143. YEC's total transmission costs in 2017 are forecast to increase by \$0.684 million over 2013 approved costs. The majority of the increases during this time frame are related to labour and increases in brushing-related expenditures which were, during the years 2014-2016, offset in part by requirements stemming from Order 2013-01, to defer certain transmission and distribution brushing costs in excess of \$0.502 million.

144. Comparing 2016 actual results with 2017 forecast amounts, YEC is anticipating total transmission cost increases in the amount of \$0.647 million, followed by a minor \$0.004 million increase forecast for the year 2018. Brushing costs are discussed later in Section 4.5.3.3 of this decision.

Table 13. Transmission Costs (\$000)

	2013 Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2017 Forecast	2018 Forecast
Labour	440	577	507	562	621	detail not provided	560	562
Brushing costs	639	948	1,161	1,069	1,034		1,182	1,161
Deferred brushing	-	-	(748)	(632)	(550)		-	-
Net brushing costs	639	948	413	437	484		1,182	1,161
Other non-labour	214	318	180	243	225		235	258
Total transmission costs	1,293	1,843	1,100	1,242	1,330		1,977	1,981

Source: YEC Application June 2017, Table 3.6, PDF page 57, and Undertaking 35, Tab 7 - Schedule 10 for 2017 Actual.

145. No issues were raised by interveners with respect to actual or forecast test year costs related to non-brushing transmission activities.

4.5.3.2 Distribution

146. YEC's total distribution costs in 2017 are forecast to increase by \$0.566 million over 2013 approved costs. The majority of the increases during this time frame are related to labour and increases in brushing related expenditures which were, during the years 2014-2016, offset in part by requirements stemming from Order 2013-01, to defer certain transmission and distribution brushing costs in excess of \$0.502 million.

147. Comparing 2016 actual results with 2017 forecast amounts, YEC is anticipating total distribution cost increases in the amount of \$0.254 million, followed by a minor \$0.007 million increase forecast for the year 2018. Brushing costs are discussed later in Section 4.5.3.3 of this Order.

Table 14. Distribution Costs (\$000)

	2013 Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2017 Forecast	2018 Forecast
Labour	592	794	912	746	837	detail not provided	845	847
Brushing costs	113	113	262	160	39		304	331
Deferred brushing	0	0	(169)	(95)	(21)		0	0
Net brushing costs	113	113	93	65	18		304	331
Other non-labour	113	209	460	476	266		226	204
Total distribution costs	819	1,117	1,465	1,288	1,121		1,375	1,382

Source: YEC Application June 2017, Table 3.7, PDF page 59, and Undertaking 35, Tab 7 - Schedule 10 for 2017 Actual.

148. No issues were raised by interveners with respect to actual or forecast test year costs related to non-brushing distribution activities.

4.5.3.3 Transmission and Distribution Brushing Costs

149. Board Order 2013-01 directed that for the period beyond 2013, transmission and distribution vegetation management (also referred to as brushing) costs greater than 2011 actual brushing costs, which were in the amount of \$0.502 million, were to be held in a newly created vegetation management deferral account.

150. YEC's total brushing costs in 2017 are forecast to increase by \$0.735 million over 2013 approved costs and by an additional \$0.005 million in 2018 over the 2017 forecast. Brushing activities have been based on adherence to YEC's brushing policy and 10-year plan, and YEC explained that, as a result of this, it has been successful in establishing a regular brushing cycle that led to an overall decrease in the number of tree-caused outages. YEC also stated that, due to an increasingly competitive bid process, better tender package results have been experienced. This has resulted in higher quality information and contractor familiarity with the geography and condition of YEC lines. YEC has developed brushing specifications to be followed by contractors as well as a guideline for brushing tender evaluation.⁴⁹ During the oral hearing, YEC confirmed that its 2017-2018 forecast brushing costs reflect mechanical brushing techniques only and that there was not provision for any herbicide application in the test years.⁵⁰

151. Comparing 2016 actual results with 2017 forecast amounts, YEC is anticipating a total transmission and distribution increase of \$0.985 million in brushing costs which comprises general costs increases in the amount of \$0.425 million and the absence of \$0.571 million of deferred costs.

Table 15. Total Net Transmission and Distribution Brushing Costs (\$000)

	2013 Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2017 Forecast	2018 Forecast
Transmission brushing	639	948	1,161	1,069	1,034	detail not provided	1,182	1,161
Distribution brushing	113	113	262	160	39		304	331
Total brushing	752	1062	1,424	1,229	1,073		1,487	1,492
Transmission deferred brushing	-	-	(748)	(632)	(550)		-	-
Distribution deferred brushing	-	-	(169)	(95)	(21)		-	-
Total deferred brushing	-	-	(917)	(727)	(571)		-	-
Net transmission brushing	639	948	413	437	484		1,182	1,161
Net distribution brushing	113	113	93	65	18		304	331
Total net brushing costs	752	1,062	507	502	502		1,487	1,492

Source: YEC Application June 2017, Table 3.6.1, PDF page 58, YEC response to UCG-YEC-1-5, Table 3.6.1, PDF page 30 for 2013 Approved, and Undertaking 35, Tab 7 - Schedule 10 for 2017 Actual.

152. CW argued that, while transmission brushing costs forecast for 2017-2018 appeared to be only slightly higher than historical actuals, distribution brushing costs forecast for 2017-2018 are significantly higher than historical actuals. CW submitted that the distribution brushing costs which are forecast in excess of \$300,000 in 2017-2018 are unrealistic and double the amount of the average recent historical actuals.⁵¹ In reply argument, CW proposed a reduction in distribution brushing costs to an amount closer to the historical average as being appropriate until such time that YEC were to demonstrate a consistent pattern of actual expenses more closely matching forecasts.⁵²

⁴⁹ YEC application, page 3-10, PDF page 58.

⁵⁰ Transcript Volume 3, June 28, 2018, page 549, lines 10-13, PDF page 118.

⁵¹ CW final argument, page 12, paragraph 42, PDF page 13.

⁵² CW reply argument, page 8, paragraph 31, PDF page 9.

153. YEC argued that its brushing costs are reasonable and consistent with its policy and studies previously reviewed by the YUB. Variations in costs from year to year reflect site-specific characteristics such as terrain, access and vegetation composition. Furthermore, YEC stated that distribution brushing costs in particular are more cyclical in nature.⁵³

154. As can be observed in the three preceding tables, YEC's response to Undertaking 35 did not provide detail at a level sufficient enough to populate the columns for 2017 actual results for either transmission, distribution or brushing costs.

155. However, the Board has prepared a summary of the available transmission and distribution cost information on a combined basis in the following table:

Table 16. Transmission and Distribution Costs (\$000)

	2013 Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2017 Forecast	2018 Forecast
Total transmission and distribution costs	2,112	2,960	2,565	2,530	2,450	3,535	3,352	3,364

Source: YEC Application June 2017, Table 3.5, PDF page 56, and Undertaking 35, Tab 7 - Schedule 10 for 2017 Actual.

4.5.3.4 Vegetation Management Deferral Account

156. As indicated earlier, Board Order 2013-01 directed that for the period beyond 2013, distribution and transmission vegetation management (also referred to as brushing) costs greater than 2011 actual brushing costs, which were in the amount of \$0.502 million, were to be held in a newly created vegetation management deferral account. In the current application, YEC has requested recovery of the deferred balance that has now accumulated at the end of 2016 to an amount of \$2.215 million over a period of 10 years and, further, seeks to have full recovery each year of its ongoing annual brushing expenses with no further deferral of costs.⁵⁴

157. YEC argued that the period of 10 years over which it was seeking approval to amortize the 2016 vegetation management deferral account balance (in the amount of \$0.222 million per year) was a period consistent with YEC's policy of amortizing deferred costs greater than \$1 million over 10 years.⁵⁵

158. Mr. Maissan stated that the vegetation management deferral account balance had been building up since 2013 and, given that the period of non-test years was expanded, the costs increases are larger than would have appeared under a shorter period of time between test years. Mr. Maissan recommended that the Board should not order YEC to defer any more costs than absolutely necessary.⁵⁶

159. CW disagreed with the recommendation of Mr. Maissan, stating that a discontinuation of deferral account treatment at this time is premature and would put ratepayers at risk if YEC were

⁵³ YEC final argument, page 25, section 2.3, PDF page 27.

⁵⁴ YEC application, pages 3-19, 3-20, PDF pages 67, 68.

⁵⁵ YEC final argument, footnote 68, page 25, PDF page 27.

⁵⁶ Mr. Maissan final argument, page 4, PDF page 5.

to “continue its pattern of spending significantly less on an actual basis than the amounts approved in its forecasts.”⁵⁷

Views of the Board

160. Based on the information provided in Undertaking 35, the Board considers that it requires further line item detail with respect to actual 2017 transmission and distribution costs, including brushing cost information in order to make a final determination on costs or YEC’s proposal to discontinue the deferral of brushing costs above 2011 levels and to amortize the balance in the vegetation management deferral account over a period of 10 years. This is in part due to a lack of clarity as to the cause of the increase in total transmission and distribution costs shown in Table 15 for 2017 actuals.

161. YEC is directed to provide this detail by way of updating the information found in tables 13, 14 and 15 for 2017 actual transmission and distribution results in its compliance filing to this decision and to explain any variances as directed by the Board in paragraph 89. YEC is also directed to provide in its compliance filing the Actual 2017 closing balance of its Deferred Vegetation Management account and to clarify whether YEC deferred any 2017 actual costs in excess of \$0.502 million.

4.5.4 General operation and maintenance costs

162. YEC’s total general operation and maintenance costs in 2017 are forecast to increase by \$0.288 million over 2013 approved costs and to decrease by \$0.019 million in 2018 over the 2017 forecast.

163. Comparing 2016 actual results with 2017 forecast amounts, YEC is anticipating general operation and maintenance cost increases in the amount of \$0.111 million, which are attributed primarily to increases in vehicle fuel costs and staff housing repairs in Dawson and Mayo.⁵⁸

164. Actual 2017 results provided in Undertaking 35 indicated an increase of \$0.250 million in total general O&M expense from the 2016 actual and a decrease from the 2017 forecast in the amount of \$0.139 million. However, detail of the costs by category was not provided in Undertaking 35 as demonstrated in the following table:

⁵⁷ CW reply argument, page 3, paragraph 11, PDF page 4.

⁵⁸ YEC response to YUB-YEC-1-10, PDF page 31.

Table 17. General Operation and Maintenance Costs (\$000)

	2013 Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2017 Forecast	2018 Forecast
Labour	250	261	414	368	366	detail not provided	394	394
Transportation	451	569	550	505	459		501	504
Maintenance of company owned properties	611	565	552	673	501		535	508
SCADA communications	93	90	219	203	197		202	207
Total General O&M	1,405	1,485	1,735	1,749	1,522	1,772	1,633	1,614

Source: YEC Application June 2017, Table 3.8, PDF page 59, and Undertaking 35, Tab 7 - Schedule 10 for 2017 Actual.

165. As observed by YEC in reply argument, no issues were raised by interveners with respect to forecast test year amounts related specifically to general operation and maintenance costs.

Views of the Board

166. Based on the information provided in Undertaking 35, the Board considers that it requires further line item detail with respect to actual 2017 general O&M costs in order to make a final determination on these costs.

167. YEC is directed to provide this detail by way of updating the information found in Table 17 for 2017 actual results in its compliance filing to this decision and to explain any variances.

4.5.5 Administration costs

168. YEC's total general operation and maintenance costs in 2017 are forecast to increase by \$0.455 million over 2013 approved costs and to decrease by \$0.198 million in 2018 over the 2017 forecast.

169. Comparing 2016 actual results with 2017 forecast amounts, YEC is anticipating administration cost increases in the amount of \$0.601 million. Increases could generally be attributed to labour increases (\$0.178 million), an increase in environmental management costs (\$0.112 million) and additional IT costs (\$0.055 million) as well as an increase in engineering-related external consulting costs (\$0.092 million). There were also increases caused by collective bargaining (\$0.095 million) offset by a reduction in external consulting costs related to regulatory affairs (\$0.066 million).

170. Actual 2017 results provided in Undertaking 35 indicated an increase of \$0.066 million in total administration expense from 2016 actual and a decrease from 2017 forecast in the amount of \$0.535 million. YEC indicated that the lower administration costs were the result of lower labour costs due to unfilled positions. However, detail of the costs by category was not provided in Undertaking 35 as demonstrated in the following table:

Table 18. Administration Costs (\$000)

	2013 Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2017 Forecast	2018 Forecast
Labour	5,008	5,301	5,547	5,516	5,783		5,961	5,911

Resource planning	26	18	9	6	14	detail not provided	48	48
Communications	105	155	100	144	129		130	130
Customer accounting	191	232	224	214	208		224	225
Environmental management	569	230	350	273	166		278	238
General	1,099	590	741	438	613		708	662
Information systems	607	481	488	537	576		631	645
Fish hatchery	187	169	124	162	157		168	168
Safety	189	164	150	165	172		171	182
Training	260	161	154	169	143		175	175
Recruitment	120	124	280	296	231		244	229
Board of directors	168	150	255	99	160		182	182
Union	23	117	-	-	-		95	20
Regulatory affairs	34	113	-	39	99		33	33
Material management	35	58	55	17	41		38	37
Contracting	16	12	8	5	14		12	12
Professional development	17	4	9	1	3		15	15
Total Administration	8,654	8,080	8,495	8,101	8,509	8,575	9,110	8,912

Source: YEC Application June 2017, Table 3.9, PDF page 61, and Undertaking 35, Tab 7 - Schedule 10 for 2017 Actual.

171. No issues were raised by interveners with respect to actual or forecast administration costs.

Views of the Board

172. Given the variance explanation provided by YEC and the minimal variance between 2016 and 2017 actuals, the Board is prepared to accept YEC's 2017 actual administration cost amounts. However, in the compliance filing to this decision, YEC is directed to update the information found in Table 18 for 2017 actual administration costs by cost category for information purposes.

4.5.6 Insurance and Reserve for Injuries and Damages (RFID) account

173. YEC's insurance cost in 2017 is forecast to increase by \$0.136 million over 2013 approved costs, with no further change in costs in 2018 over the 2017 forecast.

174. Comparing 2016 actual results with 2017 forecast amounts, YEC is anticipating insurance cost decreases in the amount of \$0.006 million.

175. With respect to YEC's annual appropriation for its RFID account, YEC proposed in its application to recover in the years 2017 and 2018 and beyond an amount of \$0.479 million. This amount is comprised of the amortization of a negative balance in the reserve account in the amount of \$0.212 million and, further, an increase in the annual appropriation, commencing in 2017, to the amount of \$0.267 million. These changes to the RFID account are discussed in Section 4.5.6.1 below.

176. Actual 2017 results provided in Undertaking 35 indicated an increase of \$0.248 million in insurance and RFID costs from 2016 Actual and virtually no change from the 2017-2018 forecast amounts.

Table 19. Insurance costs and the Reserve for Injuries and Damages (\$000)

	2013 Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2017 Forecast	2018 Forecast
Insurance costs	895	990	1,017	1,030	1,037	1,032	1,031	1,031
Reserve appropriation for RFID	226	226	226	226	226	479	479	479
Total insurance and RFID	1,121	1,216	1,243	1,256	1,263	1,511	1,510	1,510

Source: YEC Application June 2017, Table 3.10, PDF page 62, and Undertaking 35, Tab 7 - Schedule 10 for 2017 Actual.

4.5.6.1 Reserve for injuries and damages account

177. As explained by YEC, its RFID account was established to address uninsured and uninsurable losses as well as deductible portions of insured costs such that a balance could be struck between “purchasing additional insurance vs. using a self-insurance type approach”, in addition to allowing “the costs of unforeseen events to be smoothed out over a number of years to avoid rate instability for ratepayers.”⁵⁹

178. Since 2013, YEC’s RFID account balance has grown to negative \$1.059 million at the end of 2016. During this time, the annual appropriation was set at the amount of \$0.190 million per year per Board Order 2013-01.

179. In its application, YEC stated that, given the current negative balance in the reserve and a desire to avoid further negative balances, YEC is proposing to:

- a. Amortize the 2016 balance of \$1.059 million over a period of five years in an amount of \$0.212 million per year commencing in the year 2017, and;
- b. Increase the annual appropriation from \$0.190 million to an amount of \$0.267 million per year commencing in the year 2017.⁶⁰

180. These two changes would result in a total annual reserve appropriation for YEC’s RFID in the amount of \$0.479 million per year, as shown in Table 19 above.

181. Similar to his comments with respect to YEC’s vegetation management deferral account, Mr. Maissan argued that the RFID account balance had also been building up since 2013. Mr. Maissan recommended that the Board should not order YEC to defer any more costs than absolutely necessary.⁶¹

182. The UCG argued that, given one of the purposes of establishing a RFID account is to act as protection to YEC against uninsured and uninsurable losses and be a financial advantage over paying significantly higher insurance premiums, only those costs that are significant and of low probability should be charged to the RFID. UCG submitted that there was insufficient evidence

⁵⁹ YEC application, page 3-14, PDF page 62.

⁶⁰ YEC application, page 3-15, PDF page 63.

⁶¹ Mr. Maissan final argument, page 4, PDF page 5.

as to why the RFID-related expenses have been incurred, or what the alternative costs of third party insurance may have been, so YEC's requests "in this area should be denied."⁶²

183. YEC countered that UCG's assertion that there is insufficient evidence of RFID expenses since 2012 was without merit and did not provide any reasonable basis for the Board to deny the proposed 2017-2018 insurance and RFID costs.⁶³

184. In reply argument, UCG expressed disagreement with Mr. Maissan's recommendation that the Board direct YEC to not defer any more costs than necessary. The UCG stated that, given YEC's established habit of spending more than forecast, tracking these costs within a deferral account provides a means for the testing of prudence. The UCG repeated its concern that the \$10,000 threshold established within YEC's RFID policy was not "significant" for a utility with a revenue requirement in excess of \$50 million.⁶⁴

185. CW did not comment on YEC's insurance costs or RFID account proposals.

Views of the Board

186. The Board does not agree with the comments of UCG with respect to insufficient evidence on RFID-related expenses and considers that UCG has had sufficient opportunity through two rounds of IRs to ask for any detail it deemed was missing from YEC's application. With the exception of a round two IR asked by UCG requesting 2017 actual and 2018 updated information, the Board observes that UCG did not seek any other clarification of the nature of the actual insurance costs charged to the RFID by YEC.

187. The Board continues to consider that the smoothing effect provided by the use of a RFID account for insurance purposes is a benefit to ratepayers in the long term. Further, amortizing the negative RFID balance at this time in combination with a moderate increase in the annual appropriation will avoid rate instability due to the costs of significant unforeseen events in the future.

188. Based on the 2017 actual information provided in Undertaking 35 closely matching the 2017-2018 forecast amounts, the Board is prepared to approve the 2017 actual and 2018 forecast insurance and RFID costs. This includes approval of both the amortization over five years of the negative 2016 RFID balance in the amount of \$1.059 million and the updated annual RFID appropriation to an amount of \$0.267 million.

4.5.6.2 Property taxes

189. YEC's total property tax costs in 2017 are forecast to increase by \$0.370 million over 2013 approved costs, with a further increase of \$0.012 million in 2018 over the 2017 forecast. YEC attributed the property tax increases since 2013 primarily to additional property for the LNG plant and general rate increases.

⁶² UCG final argument, pages 27, 28, paragraphs 184-191, PDF pages 28, 29.

⁶³ YEC reply argument, page 11, section 3.3.3, PDF page 14.

⁶⁴ UCG reply argument, pages 6, 12, paragraphs 21, 63, PDF pages 7, 13.

190. Comparing 2016 actual results with 2017 forecast amounts, YEC anticipated property tax increases in the amount of \$ 0.010 million.

191. Actual 2017 results provided in Undertaking 35 indicated an increase of \$0.007 million in property tax expense from the 2016 actual and a decrease from the 2017 forecast in the amount of \$0.003 million.

Table 20. Property taxes (\$000)

	2013 Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2017 Forecast	2018 Forecast
Total Property Taxes	326	331	331	473	686	693	696	708

Source: YEC Application June 2017, Table 3.12, PDF page 64 and Undertaking 35, Tab 7 - Schedule 10 for 2017 Actual.

192. The UCG argued that YEC should not be granted any increase to property taxes for the test years given a lack of evidence of assessments and proof that the resulting property taxes will materialize during 2017-2018. UCG also questioned why increases for the years 2017 and 2018 forecast at 1.7 percent and 2.3 percent respectively appeared to be inconsistent with forecast property tax amounts showing year over year increases of 43 percent in 2017 and 45 percent in 2016.⁶⁵

193. YEC countered that the UCG argument is without merit, as it ignores the fact that there were actual property tax increases between the years 2013 and 2016, with 2016 costs being based on a City of Whitehorse market assessment examining constructed values for the LNG site. YEC also pointed to the Actual 2017 property tax amount of \$0.693 million provided in Undertaking 35, which supported the reasonableness of its 2017-2018 forecast amounts.

194. No other party raised issues with respect to YEC's actual or forecast property tax expense.

Views of the Board

195. The Board is not convinced by the UCG argument implying there is no evidence in support of the reasonableness of the increase in the property tax amounts. The Board observes that the 2017 actual property tax amounts of less than 0.5 percent lower than the 2017 forecast illustrates the reasonableness of YEC's applied for property tax forecasts.

196. Based on the information provided in Undertaking 35, the Board is prepared to approve the 2017 actual and the 2018 forecast property taxes in the amount of \$0.693 million and \$0.708 million, respectively.

4.6 Rate base, depreciation and amortization

197. YEC stated in its application that rate base amounts include "all investment providing service to ratepayers, as well as components of necessary working capital. It comprises property,

⁶⁵ UCG final argument, pages 6, 81, paragraphs 26, 557-561, PDF pages 7, 82.

plant and equipment (net of depreciation), deferred study and other costs, reserves set aside for various regulatory purposes and working capital...’’⁶⁶

198. Mid-year net plant in service was forecast to increase to \$437.638 million in 2017 and \$451.390 million in 2018. Increases in the 2017 forecast reflect the addition of the LNG plant, Aishihik elevator and the completion of the Takhini/Whistle Bend supply project.

199. Actual 2017 results provided in Undertaking 35 indicated mid-year rate base in the amount of \$436.967 million, which is an increase of \$11.627 million from 2016 actual results and a decrease of \$0.671 million from the 2017 forecast.

200. Capital additions, including stabilization mechanisms such as deferred charges and reserve accounts, are discussed in subsequent sections of this decision. YEC proposed a forecast net mid-year rate base of \$274.459 million for 2017 and \$291.627 million for 2018.

201. Actual 2017 results provided in Undertaking 35 indicated net mid-year rate base in the amount of \$274.040 million. This is an increase of \$15.980 million from 2016 actual results and a decrease of \$0.419 million from the 2017 forecast.

Table 21. Mid-year rate base (\$000)

	2013 Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2017 Forecast	2018 Forecast
Previous closing net plant in service	222,393	217,202	216,836	250,737	251,405	not provided	282,219	286,197
Mid year:								
Current year plant in service	386,941	382,576	379,478	402,204	425,340	436,967	437,638	451,390
Less contributions	166,023	165,732	162,459	168,417	174,269	170,785	170,826	167,181
Net plant in service	220,918	216,844	217,019	233,787	251,071	266,182	266,812	284,208
Mid-year regulatory deferral excluding DSM and hearing reserve	1,486	1,693	1,367	2,007	2,061	2,402	2,447	2,208
Working capital	4,280	4,521	4,495	4,791	4,928	5,456	5,200	5,210
Net mid-year rate base	226,684	223,058	222,881	240,585	258,060	274,040	274,459	291,627

Source: YEC Application June 2017, Table 3.13, PDF page 64, and Undertaking 35, Tab 7 – Schedule 1 for 2017 Actual.

202. As illustrated in Table 22 below, total 2017 depreciation and amortization expense was forecast in the amount of \$10.814 million, which was an increase of \$2.210 million over 2013 approved costs. YEC forecast a further increase of \$0.280 million in 2018, resulting in a total depreciation and amortization amount of \$11.094 million. YEC attributed the increases in depreciation and amortization expense to rate base additions and overhauls and other deferred costs (previously held in WIP) added to rate base during the test years that were now subject to

⁶⁶ YEC application, page 3-16, PDF page 64.

depreciation and amortization. The effect of the increase in deferred-cost amortization in the 2017 forecast was approximately \$2.3 million.⁶⁷

203. Actual 2017 results provided in Undertaking 35 indicated depreciation and amortization expense in the amount of \$11.013 million, which is an increase of \$3.197 million from 2016 actual results and a decrease of \$0.199 million from the 2017 forecast.

204. YEC proposed no changes to the average service lives of its assets upon which depreciation expense is calculated other than for two new asset classes capitalized since the last GRA. In response to an IR, YEC explained that the LNG storage and LNG fencing assets were using depreciation rates based on estimated service lives not previously reviewed by the YUB nor supported by a depreciation study.

205. While the majority of the LNG project assets were classified into the same depreciation groupings as diesel equipment, the LNG Storage assets were dissimilar, and therefore, YEC based its 32-year service life estimation on discussions with the equipment supplier. With respect to LNG Fencing assets, YEC estimated the service life at 30 years, which was longer than the 20-year service life being used for YEC's general fencing assets but was reasonable given a higher level of construction standards applicable to the newly constructed fencing.⁶⁸

Table 22. Depreciation and amortization (\$000)

	2013 Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2017 Forecast	2018 Forecast
Fixed asset depreciation	8,989	8,894	8,906	9,828	10,615	12,323	12,217	12,419
Customer contributions	(3,569)	(3,677)	(3,691)	(3,624)	(4,102)	(5,539)	(5,007)	(4,938)
Amortization of fire insurance recoveries	(262)	(262)	(262)	(262)	(262)	(262)	(262)	(262)
Disallowed depreciation	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
Amortization of deferred charges	3,462	4,561	2,846	2,764	1,581	4,507	3,883	3,891
Total depreciation and amortization	8,604	9,500	7,783	8,690	7,816	11,013	10,814	11,094

Source: YEC Application June 2017, Table 3.14, PDF page 65, and Undertaking 35, Tab 7 - schedules 5 and 10 for 2017 Actual.

206. During the hearing,⁶⁹ YEC noted that, with respect to the depreciation period on the Aishihik elevator shaft refurbishment, an update was required to the estimated service life of 72 years that should more appropriately be 40 years, based on a review of the life cycle of the original installation. YEC committed to correcting the depreciation calculation to reflect a service life of 40 years in the compliance filing.⁷⁰

207. The UCG argued that the depreciation related increases resulting from YEC's capital expenditures program between the years 2013 and 2018 represented a 38 per cent increase in

⁶⁷ YEC application, page 3-18, PDF page 66 and YUB-YEC-1-5, PDF page 20 and YEC rebuttal, page B-4, PDF page 30.

⁶⁸ YEC response to YUB-YEC-1-18, PDF pages 55-56.

⁶⁹ Transcript, Volume 1, June 26, 2018, pages 18-19, lines 16-11.

⁷⁰ YEC response to JM-YEC-1-24, PDF page 149.

depreciation expense in just five years. The UCG submitted that the “expense associated with the escalation of the depreciation of fixed assets has gotten out of control.”⁷¹

208. The UCG asserted that, given it had been eight years since KPMG conducted the last depreciation study on YEC’s assets, it had no confidence with respect to YEC’s ability to defend the proposed depreciation of its assets. Specifically, UCG stated that, not only was it essential that the proposed service lives of the two new LNG assets be supported by depreciation experts, there should be a requirement for YEC to “regularly review how utility assets are depreciated, and it is equally important to have all Yukon utility assets reviewed at the same time (i.e. including AEY) to ensure consistency.” The UCG recommended that “the YUB should deny the request to change depreciation rates due to a lack of supporting evidence and the lack of a formal request for approval.”⁷²

209. The UCG was also critical of the lack of information provided by YEC when requested to provide a detailed working paper that applies the “depreciation rates” used to arrive at total depreciation and amortization expense.⁷³

210. YEC argued that it was not necessary to incur additional expense for expert testimony on depreciation given there was a limited number of changes being put forth. YEC pointed to its response to YUB-YEC-1-18 as reasonable evidence in support of the service lives proposed for the two LNG asset classes.

211. No other party raised any issues with respect to YEC’s actual or forecast depreciation and amortization expense.

Views of the Board

212. The Board is not persuaded by the UCG argument that a problem exists with respect to YEC’s “depreciation rates.” In response to an IR, YEC clarified that, with the exception of the two LNG assets discussed above, it has used only depreciation parameters and the implied depreciation rates that had been previously presented in a depreciation study, tested in a GRA, or specifically approved by the Board.⁷⁴ The Board considers that YEC did not make a formal request for approval of its “depreciation rates” because it had not requested a change to any of the depreciation parameters that inform an implied depreciation rate. For these reasons, the UCG recommendation for denying a change in YEC’s depreciation rates is moot. Nonetheless, the Board considers that, given it has been eight years since the time of YEC’s last full depreciation study, it would be beneficial for a full depreciation study to be completed, so as to avoid the potential for large changes to depreciation expense that could be associated with incorporating material changes to asset service lives. YEC is directed to submit a full depreciation study at the time of its next GRA.

⁷¹ UCG final argument, page 79, paragraph 545, PDF page 80.

⁷² UCG final argument, page 80, paragraphs 555, 556, PDF page 81.

⁷³ UCG final argument, pages 79, 80, paragraph 549, PDF pages 80, 81 referencing YEC’s responses to CW-YEC-1-26, YUB-YEC-1-17 and YUB-YEC-1-18.

⁷⁴ YEC response to YUB-YEC-1-18, PDF page 55.

213. The Board, however, does agree with the UCG observation that detail with respect to YEC's depreciation expense calculations was not easily obtained. It was not until asked a second time⁷⁵ to provide the detailed depreciation and amortization expense calculations that YEC responded with the requested information. The Board considers this information to be essential in facilitating a review of YEC's depreciation and amortization expense irrespective of whether or not a change in depreciation parameters has been requested. YEC is directed to provide detailed depreciation and amortization calculations in all future GRAs consistent with the attachments provided with its response to YUB-YEC-2-27. This information may be included as an additional schedule within YEC's existing Tab 7 format.

214. The Board approves YEC's actual 2017 and forecast 2018 depreciation and amortization expense amounts, subject to any findings made elsewhere in this decision with respect to capital additions or specific deferral or reserve accounts. The Board directs that any findings made elsewhere in this decision that will affect YEC's depreciation and amortization expense calculation to be incorporated in its compliance filing to this decision.

4.7 Deferral and reserve accounts

215. In this section the Board will review YEC's requested changes to its hearing cost reserve account followed by Board comments on YEC's process for managing and reporting information with respect to its deferral and reserve accounts. In general, the observations contained in Section 4.7.2 are with respect to YEC's non-capital-related deferral and reserve accounts.

216. The Board also notes that specific determinations with respect to YEC's vegetation management deferral account and reserve for injuries and damages account have been dealt with earlier in sections 4.5.6 and 4.5.6.1, respectively.

4.7.1 Hearing cost reserve account

217. In its application, YEC stated that since the hearing cost reserve account was established in Order 2013-01, and given there has been minimal costs since 2013, it was proposing to amortize the 2016 credit balance of \$0.973 million over a five-year period (\$0.195 million per year) and to decrease the annual provision to the hearing cost reserve account to an amount of \$0.250 million per year from the original provision of \$0.550 million per year.

218. No party raised any issues with respect to YEC's proposed changes for this reserve account.

Views of the Board

219. The Board accepts YEC's rationale for its proposed changes to the hearing cost reserve account and finds it reasonable for YEC to amortize the credit balance in the account and to decrease the annual provision as described above.

⁷⁵ YEC response to YUB-YEC-2-27, PDF page 462 and attachments 1 and 2 provided in Excel format on April 9, 2018.

4.7.2 Comments on YEC's deferral and reserve accounts

220. Throughout the IR process and oral hearing, a significant amount of time was expended in an effort to understand the relationship between the reporting of YEC's deferral and reserve accounts on the rate base schedules (for example, Schedule 1 of Tab 7) and the revenue requirement schedules (for example, schedules 5 and 6 of Tab 7).

221. The Board observes that the deferral and reserve account categories used on Schedule 1 consisted of the following line items: Miscellaneous reserves (line 6), Deferred study costs (line 8) less Studies in progress (line 9) and Mid-year regulatory deferral (line 18). However, when attempting to cross reference the revenue requirement (or costs) applicable to these rate base categories on Schedule 5, for example, other naming and grouping conventions were used.

222. For example, within Schedule 1, the Miscellaneous reserves account (line 6) consisted of the RFID and Deferred gain on fire insurance proceeds categories.⁷⁶ When cross referencing the applicable costs to Schedule 5, the Board observes that while the RFID costs were shown as a separate line item (line 8), the Deferred gain on fire insurance proceeds was combined with the Amortization of contributions category (line 10).

223. In another example within Schedule 1, the Deferred study costs (line 8) consisted of several categories: Vegetation management (or brushing), Feasibility and licensing, Dam safety review, DSM and hearing cost reserve.⁷⁷ When cross referencing the applicable costs to Schedule 5 within the Amortization of deferred costs (line 7), the Board observes that, while some of the corresponding costs could be cross-referenced to Schedule 5, line 7 (being the Amortization of hearing cost reserve account, Amortization of feasibility, Amortization of relicensing, Amortization of dam safety and Amortization of brushing), costs related to DSM were not included as an identifiable component of Schedule 5, line 7, but were found to be included with the Amortization of Regulatory costs⁷⁸ (which can be cross-referenced as originating from a separate rate base item on Schedule 1 (line 18) named Mid-year regulatory deferral.⁷⁹

224. Further complicating YEC's reporting was the fact that several of the account categories were reported inconsistently with respect to offsetting contributions. Some schedules and IR responses disclosed the deferral or reserve account information on a gross (pre-contribution) basis, and some were reported on a net-of-contribution basis. Furthermore, there was inconsistency between years as to whether a deferral or reserve account was reported pre- or net-of-contributions. YEC acknowledged that "this inconsistent presentation in the GRA filing is without any specific rationale and has caused confusion..." while maintaining that, despite the issues inherent in its approach to the presentation of the deferral or reserve account and associated contributions, there was no impact on revenue requirement or customer rates.⁸⁰

⁷⁶ YEC response to YUB-YEC-1-12, Table 1, PDF page 36.

⁷⁷ YEC response to YUB-YEC-1-12, Table 2, PDF page 37.

⁷⁸ Undertaking 33 at page 535, line 24 to page 536, line 21.

⁷⁹ YEC responses to YEC-YUB-1-12, PDF pages 35-40 and YEC-YUB-2-26, page 12, PDF page 12

⁸⁰ YEC response to YUB-YEC-3-9, July 27, 2018, PDF pages 305-309.

225. In a similar vein, the Board reviewed other supplemental information provided by YEC in its application, namely Tables 5.3 through 5.8, which are Continuity Schedules of Deferred Costs for the years 2013 to 2018. The schedules, while appearing to contain detailed information with respect to the expenditures and amortization of the significant number of feasibility and other regulatory studies and projects, were not easily cross-referenced to information provided in individual schedules within Tab 7 or YEC's main application.

Views of the Board

226. It is the Board's view that YEC's management and reporting of deferral and reserve accounts has led to unnecessary inefficiencies and confusion with respect to the processing of its application. For this reason, the Board directs YEC to re-establish its standard of disclosure to one that is transparent, consistent and provides cross-referencing among each of the interrelated rate base and revenue requirement items and the individual components comprising each item. This applies equally to the disclosure on YEC's Tab 7 schedules and any supplementary information within YEC's application.

4.8 Return on rate base (interest costs and return on equity)

227. Return on rate base was discussed in Section 3.5 of the application (pages 3-20 to 3-23). YEC forecast a total return on its mid-year net rate base as shown in the following table:

Table 23. YEC 2017-2018 Return on Rate Base Parameters

	2017	2018
Return \$(millions)	13.289	14.348
Average Cost of Capital (%)	4.84	4.92
Equity Ratio (%)	40	40
Debt Ratio (%)	60	60
Forecast Debt \$(millions) (mid-year)	164.7	110.3
Forecast Equity \$(millions) (mid-year)	175.0	116.7

228. YEC did not change these parameters in the alternative short-term forecast provided on December 18, 2017.

4.8.1 Costs of debt

229. Details of YEC's long-term debt and applicable interest rates are provided in Schedule 11 of Tab 7 (financial schedules) of the application. Explanations on each of the debt instruments are provided on pages 3-21 to 3-22 of the application. In order for YEC to maintain its debt ratio at 60 percent, YEC forecasts additional long-term debt (LTD) of \$23.828 million for 2017 and \$7.004 million for 2018. The forecast interest rate for both years is 2.15 percent.

230. In comparing YEC's original GRA forecast to the alternative short-term GRA forecast, all parameters remain the same except for the issuance of new debt. In the alternative short-term GRA forecast, YEC forecasts new debt of \$23.742 million (\$23.828 million in the original forecast) for 2017 and \$7.246 million (\$7.004 million in the original forecast) for 2018.

231. Mr. Maissan recommended that the Board accept the cost of debt as proposed by YEC.

232. The UCG submitted:

In its Order 2013-01, the YUB adopted an historical formulaic approach (120 basis points above long-term Canada bonds) for forecasting future costs of debt for YEC. The YUB agreed with intervenors that such an approach creates a simplification which reduces the regulatory burden and brings the cost-of-debt approach congruent with YEC's approach for ROE.

YEC has not provided any expert advice regarding its proposed cost of debt.

UCG submits that the same formulaic approach (120 basis points above long-term Canada bonds) for forecasting future costs of debt for YEC should continue to be used for YEC so that Yukon ratepayers are not burdened with additional interest fees. Consistency in the YUB's approach would add to the understandability of the regulatory process.

Notwithstanding YEC's apparent high degree of confidence in the accuracy of their forecast, UCG suggests that the long-term Canada rate is largely a matter of speculation as well as the actual rates that the market will demand when the debt issue may occur. UCG submits that the YUB must also be aware of the fact that YEC has some ability to control the date of issuance to garner a favourable rate.⁸¹ (paragraph numbering removed)

233. YEC responded:

In response to UCG's argument to retain the formulaic approach with 120 basis points above long-term Canada bonds, the Application provides for a market-based lower cost option available at this time. YEC has confirmed the market basis, as provided to YEC by the TD Bank, for the interest rate of 2.15% forecast for new 25-year debt during the test years.⁸² (footnote removed)

Views of the Board

234. Actual debt costs for YEC for 2017, as reflected in Undertaking 35, are not accepted by the Board in this decision as it is not clear that those debt costs were based on a Board-approved rate for that cost of debt.

235. The Board acknowledges the UCG comments regarding Board Order 2013-01 in which the Board stated:

The Board notes the recommendation by CW that YEC should use the historical formulaic approach (120 basis points above long-term Canada bonds) for forecasting future costs of debt. Such an approach, according to CW, creates a simplification which reduces the regulatory burden and brings the cost-of-debt approach congruent with YEC's approach for ROE. Based on the above reasoning, a forecast cost of new debt should be 3.97 percent for 2012 and 3.58 percent for 2013.⁸³ (footnote removed)

⁸¹ UCG final argument, page 85, paragraph 588, PDF page 86.

⁸² YEC reply argument, page 14, section 3.5.1, PDF page 17.

⁸³ Board Order 2013-01, Appendix A: Reasons for Decision, March 25, 2013, page 41, paragraph 192, PDF page 42.

236. The Board remains of the view that such an approach creates a simplification which reduces the regulatory burden and brings the cost-of-debt approach congruent with YEC's approach for ROE.

237. However, in this proceeding, there is no evidence on the record as to what the rate is for long-term Canada bonds. Further, no party has disagreed with the submission of YEC that its application provides a market-based lower cost option available at the time of the application. Therefore, for purposes of this decision, the Board accepts the forecast market rate for YEC's cost of debt of 2.15 per cent for each of the 2017 and 2018 test years.

238. In Board Order 2013-01,⁸⁴ the Board directed that a formulaic approach be used for forecasting future costs of debt. This direction was not followed. The Board reiterates the direction and expects this direction to be followed. In future GRAs, both Yukon utilities are to provide their cost-of-debt forecast based on the formulaic approach (long-term Canada bonds plus 120 basis points). If a utility chooses to employ a market-based approach, that utility must also provide a forecast based on the approved formulaic approach.

4.8.2 Capital structure and return on common equity

Capital Structure

239. YEC did not propose any changes to its historical capital structure of 40 percent equity and 60 percent debt.

240. In argument, UCG stated:

UCG submits that there has been no evidence put on the record of this proceeding that persuades the YUB to alter the previously approved capital structure for YEC. At the same time, there has been no evidence provided that adequately confirms that there hasn't been, nor will there be, significant changes to YEC's business and/or financial risks.

UCG submits that continuing to link YEC's return on equity to cost of capital formulas developed in other jurisdictions will reduce regulatory costs but should also warrant a review of the equity thickness of YEC's capital structure. Given that YEC's return on equity has and should be established based on levels established in Alberta, UCG submits that YEC's equity thickness should be reduced to 37% to match the level established by the Alberta Utilities Commission for its benchmark utility (see additional detail below).⁸⁵

241. YEC's response to UCG was:

UCG's argument is without merit or use to the Board, as it focuses on untested AUC evidence without any explanation or recognition as to the divergence from YEC's Application and the recent Board rulings for AEY which were both based on BCUC rather than AUC evidence.⁸⁶

⁸⁴ Board Order 2013-01, Appendix A: Reasons for Decision, March 25, 2013, page 41, paragraphs 192, 194, PDF page 42.

⁸⁵ UCG final argument, pages 82, 83, paragraph 568, PDF pages 83, 84.

⁸⁶ YEC reply argument, page 40, section 7.0, PDF page 43.

Views of the Board

242. The Board notes that YEC's capital structure of 60 percent debt and 40 percent equity has been previously approved by the Board, most recently through Board Order 2013-01. The Board finds that the UCG submission to set equity thicknesses based on standards established in Alberta were not supported by evidence. As such, these submissions were not of assistance to the Board. Nothing on the record of this proceeding supports a change to the applied for and previously approved capital structure for YEC. The Board accepts the YEC capital structure of 40 percent equity and 60 percent debt.

4.8.3 Cost of Equity

243. YEC has forecast a return on equity (ROE) of 8.82 percent for both 2017 and 2018. The requested ROE was determined from the most recent BCUC benchmark of 8.75 percent plus a risk premium of 0.57 percent and then a reduction of 0.50 percent as required by *Order-in-Council* (OIC) 1995/90. Further information on the ROE was provided in Section 8 of the application (pages 8-1 to 8-9).

244. In requesting its ROE, YEC stated that since its 1998 rate revision application, the ROE has been set by reference to the British Columbia Utilities Commission (BCUC) formulaic approach. This approach was used again in the 2005 Required Revenues and Related Matters Proceeding and in YEC's 2008-2009 GRA. Also, Board Order 2009-08 stated that the BCUC approach would be the precedent for Yukon until otherwise ordered. With the exception of YEC's 2012-2013 GRA where there was not a recent BCUC decision on ROE and capital structure,⁸⁷ the BCUC precedent has been maintained in Yukon.

245. For this application, YEC used a three-step process to determine its ROE. First, YEC used the most recently established BCUC benchmark of 8.75 percent.⁸⁸ Second, YEC determined its risk premium by referencing Board Order 2005-12, which accepted YEC's proposal of a risk premium of 52 points as the midpoint between FortisBC Electric (40 basis points) and PNG-West (65 basis points). For this application, YEC referenced a recent BCUC decision⁸⁹ and requested a risk premium of 57.5 basis points, giving a ROE of 9.325%. The last step YEC undertook was to reduce the ROE by 50 basis points, pursuant to OIC 1995/90, netting a ROE for this application of 8.82 percent for each test year.

Views of the Board

246. Other than UCG, no intervener took issue with respect to using the BCUC benchmark of 8.75 percent. The Board has consistently determined, for regulatory efficiency, that the ROE for Yukon utilities will be based on the results of the BCUC generic cost of capital (GCOC) proceeding. The benchmark utility for the BCUC is FortisEnergy Inc. (FEI). The established BCUC benchmark has been set at 8.75 percent. For this proceeding, the Board continues to

⁸⁷ For the YEC 2012/13 GRA, since there was not a recent BCUC benchmark decision, the Board approved using the Alberta Utilities Commission benchmark ROE. Subsequent to that application, all ROE matters have been referenced to the most recent BCUC benchmark ROE decisions.

⁸⁸ Decision G-129-16, BCUC Generic Cost of Capital (GCOC) proceedings, issued August 10, 2016.

⁸⁹ Decision G-47-14, BCUC GCOC Stage 2 decision, March 25, 2014.

approve the use of the ROE of the benchmark utility from the BCUC as the base or starting point for determining the ROE for Yukon utilities.

247. As a result, the Board is not persuaded by the UCG submissions that the Board should apply the rate of return on equity established for the utilities regulated by the Alberta Utilities Commission (8.5 percent for 2017 and beyond) because it is more current than the BCUC benchmark and consistent with the ROE currently incorporated in rates being charged by YEC.⁹⁰

4.8.4 Basis for Risk Premium

248. YEC noted that in past proceedings⁹¹ the risk premium for YEC was determined as the mid-point between two BCUC-regulated utilities (FortisBC Electric and Pacific Northern Gas [PNG] West). In addition to the two previous YEC proceedings, YEC referred to the Board decision⁹² on AEY's 2016-17 GRA where the Board confirmed the BCUC benchmark will continue to apply to Yukon utilities. YEC added that its risk premium request was based on the size of YEC operations compared to other utilities, its financial structure, mix of customers serviced and source of energy supply.⁹³ To support its position, YEC listed risk factors such as size of operations, financial structure, customer counts, reliance on its own generation, lack of interconnection with external electricity markets and fluctuation of business risk related to industrial customers.⁹⁴ YEC provided Tables 8.1 and 8.2 to illustrate its comparison to other utilities.

249. YEC did not change any of its submissions on ROE and risk premium in its ST Alternative forecast.

250. In response to information request CW-YEC-1-28(a), YEC stated that it has long been accepted by the Board that YEC faces higher risk than AEY. This information response also referred to Appendix A of Board Order 2009-02,⁹⁵ in which the Board found that YEC has more risk than AEY, is without the same intertie connections as FortisBC (Electric), and that AEY is more risky than FortisBC (Electric). As a result, the Board found it reasonable to place the risk premium for AEY at the midpoint of the risk premiums between YEC and FortisBC (Electric).

251. In CW-YEC-1-28(a), YEC also referred to Appendix A to Board Order 2005-12. In that Order, the Board stated:

As for the issue of risk premium, the Board agrees that YEC likely falls somewhere between PNG at 65 basis points, and FortisBC at 40 basis points.⁹⁶

⁹⁰ UCG final argument, page 84, paragraph 580, PDF page 85.

⁹¹ Specifically, the 2005 Required Revenues and Related Matters and the YEC 2008/09 GRA proceedings.

⁹² Board Order 2017-01, Appendix A: Reasons for Decision, AEY 2016-2017 GRA, April 27, 2017, page 78, , PDF page 79.

⁹³ YEC application, page 8-5, lines 3, 4, PDF page 298.

⁹⁴ YEC application, page 8-6, lines 21-26, page 8-7, lines 7-14; PDF pages 299, 300.

⁹⁵ Board Order 2009-2, Appendix A: Reasons for Decision, page 29, PDF page 31.

⁹⁶ Board Order 2005-12, Appendix A: Reasons for Decision, page 45, PDF page 45.

252. CW took the position that, absent more strict or precisely defined rules governing the DCF, YEC's 2017 and 2018 ROE should be reduced.⁹⁷ CW added that if the DCF is to remain as-is, then the ROE awarded to YEC should be lower than the applied for amount and suggested that the 57 basis point risk premium requested by YEC for 2017 and 2018 be eliminated.⁹⁸

253. The UCG argued that YEC is at a lower risk due to deferral account "safety nets" (e.g., the DCF), ongoing bailouts and contributions by the Yukon government and Yukon Development Corporation (YDC) when trying to get projects in place and revenue guarantees provided by mechanisms like rate relief programs and the ERA. It appears to UCG that the use of the DCF to relieve YEC from operational risk would distinguish YEC from most comparators in a way that may not have been captured previously.⁹⁹ The UCG then concluded with:

UCG submits that YEC has not provided any evidence that they have completed any analysis of the risk-reducing nature of its deferral accounts (DCF, RFID, Site Restoration [RFSR], etc.) and there has been no evidence presented by YEC to justify a difference in risk from the benchmark utility in Alberta.

UCG submits that YEC should be directed to use the low risk utility return on equity approved by the Alberta Utilities Commission and that there should not be any add-on of additional risk premium. UCG recommends that YEC's return on equity for 2017 and 2018 be set at 8.0% (8.5% - 0.5%).¹⁰⁰ (underlining omitted)

254. Mr. Maissan stated that the ROE calculations appeared to be straightforward and recommended that the Board approve the ROE as proposed by YEC.

255. YEC submitted that its Rebuttal Evidence addressed CW's arguments on reducing the risk premium based on the DCF and/or other deferral accounts that reduce YEC's risk. YEC pointed to the fact that the BCUC assessed FBC as having a risk premium of 40 basis points despite FBC having deferral accounts that exceed any coverage of risk addressed by YEC's DCF and other deferral accounts (i.e. YEC's risk as a generation utility clearly exceeds the risk applicable to FBC, and YEC's risk premium over the BCUC benchmark utility is therefore greater than 40 basis points). YEC submitted that the requested risk premium is consistent with past rulings of the Board based on BCUC evidence as applied to YEC.¹⁰¹

256. With respect to the UCG submissions, YEC stated it cannot see any basis for UCG's argument that removal of any risk premium would leave YEC with an 8.5 percent ROE, i.e. absent any risk premium, YEC's ROE would equal the 8.75 percent benchmark ROE less 50 basis points (i.e. the current 8.25 percent ROE). YEC then added that UCG's argument is without merit or use to the Board because it focuses on untested AUC evidence without any explanation or recognition as to the divergence from YEC's application and the recent Board rulings for AEY which both were based on BCUC rather than AUC evidence.¹⁰²

⁹⁷ CW final argument, page 13, paragraph 48, PDF page 14.

⁹⁸ CW final argument, page 15, paragraphs 53, 54, PDF page 16.

⁹⁹ UCG final argument, page 84, paragraph 581, PDF page 85.

¹⁰⁰ UCG final argument, page 85, paragraphs 583, 584, PDF page 86.

¹⁰¹ YEC reply argument, page 40, section 7.0, PDF page 43.

¹⁰² YEC reply argument, page 40, section 7.0, PDF page 43.

Views of the Board

257. The Board recognizes that YEC has previously requested, as it continues to do in this application, that its ROE be based on the mid-point of the risk premiums for FortisBC (Electric) and PNG-West. The Board previously awarded YEC a risk premium at the mid-point between FortisBC Electric and PNG-West.

258. In Appendix A: Reasons for Decision to Board Order 2017-01,¹⁰³ the Board examined AEY's request for a risk premium and the related BCUC decisions regarding the establishment of the ROE for the benchmark utility and the risk premiums for other utilities relative to the benchmark utility. In those BCUC proceedings, the BCUC determined the risk premium for FortisBC Electric to be 40 basis points above the benchmark utility (FEI). Of the factors examined for the risk premium, the BCUC determined that size, generation risk and energy price competitiveness were the most pertinent factors in determining the risk premiums.

259. To determine a risk premium, the Board must examine risk. For the definition of risk, the Board accepts the definition used by the BCUC. The BCUC defined risk "as the probability that future cash flows will not be realized or will be variable resulting in a failure to meet investor expectations."¹⁰⁴

4.8.4.1 BCUC considerations in determining the risk premium for FortisBC (Electric)

260. In this application, YEC used FortisBC (Electric) as a comparator. When the BCUC compared FortisBC (Electric) to the benchmark utility Fortis Energy Inc. (FEI), the BCUC looked at the following areas:

- Smaller size, More concentrated assets and Less diverse customer and economic base;
- Energy price competitiveness;
- Supply risk;
- Operating risk; and
- Financial risk related to its credit profile.

261. In BCUC Decision G-47-14, the Commission determined:

While FBC is smaller than the Benchmark, it is nonetheless a sizable entity with many customers. In the Commission Panel's view, the more relevant factor is business risk associated with FBC's reliance on a relatively small wholesale and industrial customer base and its overall reliance upon the forestry industry. We acknowledge the cyclical nature of the forestry industry and its sensitivity to many external factors, both international and local. However, we also note that this is not a unique circumstance as many industries face similar issues. Rather, what separates FBC from the Benchmark is its heavy reliance on one

¹⁰³ Board Order 2017-01, Appendix A: Reasons for Decision, AEY 2016-2017 GRA, April 27, 2017, page 42, paragraph 208, PDF page 43.

¹⁰⁴ YUB-YEC-1-52, Attachment 2, BCUC Decision G-75-13, decision page 36, 4, PDF page 1082.

industry. This lack of wholesale and industrial diversity is a factor the Panel considers to be relevant and worthy of some weight.¹⁰⁵

262. Specifically with respect to size, the BCUC determined:

As compared to the Benchmark, the Panel places significant weight on the small service areas and less diverse customer and economic bases for both FEVI and FEW. Minimal weight has been applied to supply and competition risks for both utilities but consideration has been given to the importance of maintaining current credit ratings for FEVI in determining an appropriate equity ratio. An additional 25 bps was awarded FEW in recognition of risks related to its small size.¹⁰⁶

263. In terms of customer diversity, the BCUC noted that the City of Kelowna distribution system acquisition is directionally positive in reducing business risk and stated that:

... FBC does face more risk than the Benchmark with respect to size related issues such as concentrated assets, and the lack of diversity in both its customer and economic base and the Panel places some weight on this difference.¹⁰⁷

264. In terms of energy price competitiveness, the BCUC stated:

The Commission Panel finds that the evidence supports FBC facing additional risk due to competitive pricing factors when compared with the Benchmark. The primary reason for this is the fact that relative to the price of electricity, natural gas is less expensive, which is important in that the service areas of FBC and FEI overlap to a large degree ...

...

The Commission Panel acknowledges that there are wholesale and industrial customers that have options available to them allowing them to discontinue their service. The question is whether it is probable that such an event will occur.

...

The Panel accepts that the risk continues to exist but is not persuaded that there is a probability of such customer loss occurring. The Panel notes ICG's comments on behalf of a major customer and FBC's response that if there is the potential for savings that industrial customers will consider all options. The Commission Panel agrees with FBC but notes that it cuts both ways. The fact that Celgar has remained a customer indicates that Celgar has not determined it is in its best interest to pursue other options. Hence, the Commission Panel places minimal weight on this risk.¹⁰⁸

265. In terms of energy supply risk, the BCUC determined:

With respect to availability of supply, FBC has acknowledged there is little difference compared to the Benchmark and describes availability risk as 'fairly low.' Neither ICG nor BCPSO took issue with this characterization nor does the Commission Panel. The

¹⁰⁵ YUB-YEC-1-52, Attachment 3, BCUC Decision G-47-14, decision page 80, PDF page 1300.

¹⁰⁶ YUB-YEC-1-52, Attachment 3, BCUC Decision G-47-14, decision page 11, PDF page 1231. In the context of the quote, FEVI refers to Fortis Energy Vancouver Island, and FEW refers to Fortis Energy Whistler.

¹⁰⁷ YUB-YEC-1-52, Attachment 3, BCUC Decision G-47-14, decision page 81, PDF page 1301.

¹⁰⁸ YUB-YEC-1-52, Attachment 3, BCUC Decision G-47-14, decision page 85, PDF page 1305.

remaining issues are concerned with whether there is a risk differential between an integrated generation, transmission and distribution utility such as FBC and one like FEI that is transmission and distribution only.¹⁰⁹

With respect to vertical integration, the Commission Panel accepts FBC's submission that adding a higher systematic risk entity to a portfolio will raise the risk of that portfolio. However, the question remains as to whether the generation assets add risk to FBC, and if they do, whether this risk is higher or lower than that of the Benchmark. FBC has made the case that business risk has increased due to the risk that one of its generating plants will fail resulting in the need to purchase power immediately on the open market at potentially higher prices. The Commission Panel accepts that there may be instances where such an event may occur and would result in a higher supply cost risk. However, in considering whether this potential risk might also exist for FEI, the Panel notes that a similar position was taken by FBCU in the Stage 1 proceeding with respect to risks associated with the BC shale deposits not guaranteeing a reliable supply of natural gas at reasonable prices. The Commission in Stage 1 accepted FBCU's position that the current environment is uncertain and stated that "[u]ntil this has been determined, the continuity of current low price levels for natural gas will be at some risk." It therefore appears that both FBC and FEI face risks that have the potential to drive higher commodity prices.¹¹⁰ (underlining added)

Accordingly, the Commission Panel finds that the risks faced by FBC with respect to supply do not differ significantly from those faced by the Benchmark. In the view of the Panel both utilities have similar access to the respective commodities, and both face potential challenges which could impact commodity pricing. (bolding removed)

266. For operating risk, the BCUC noted that FortisBC (Electric) has generation assets, while FEI had none.¹¹¹ The BCUC stated:

In its evidence, FBC raised these risk issues yet did not clearly connect them to the probability of them occurring or their impact on future cash flows. Therefore, it is difficult to assign any weight to operational risk as a factor in determining FBC's cost of capital.

Accordingly, the Commission Panel finds that although there are differences in operational risk between FBC and the Benchmark there is no basis upon which to establish the potential impact of these differences. Accordingly, the Commission Panel gives these operational risks limited weight.¹¹² (bolding removed)

267. The BCUC did not make an adjustment to the risk premium for credit metrics, short-term risks and deferral accounts.¹¹³

268. In summary, the BCUC considered that size and customer diversity, energy price competitiveness, energy supply and generation were the most influential factors in setting a risk premium.

¹⁰⁹ YUB-YEC-1-52, Attachment 3, BCUC Decision G-47-14, decision page 90, PDF page 1310.

¹¹⁰ YUB-YEC-1-52, Attachment 3, BCUC Decision G-47-14, decision pages 90, 91, PDF pages 1310, 1311.

¹¹¹ YUB-YEC-1-52, Attachment 3, BCUC Decision G-47-14, decision page 93, PDF page 1313.

¹¹² YUB-YEC-1-52, Attachment 3, BCUC Decision G-47-14, decision page 94, PDF page 1314.

¹¹³ YUB-YEC-1-52, Attachment 3, BCUC Decision G-47-14, decision pages 94-99, PDF pages 1314-1319.

4.8.4.2 Risk premium due to small size and comparability to PNG-West

269. With respect to AEY, in Appendix A: Reasons for Decision to Board Order 2017-01, the Board determined that the risk premium due to small size of 25 basis points over the BCUC benchmark utility is reasonable for this jurisdiction.¹¹⁴ Based on the reasoning in that decision, the Board gives YEC a risk premium of 25 basis points for its small size.

270. However, the Board notes that in setting the risk premium for PNG-West, the BCUC considered factors that are not relevant to this proceeding.

271. PNG-West was evaluated as part of a different grouping than FortisBC (Electric). The largest factor determining the risks faced by PNG-West is customer growth. PNG-West had experienced negative customer growth for nine consecutive years covering the 2003 to 2012 period. In total, this amounted to close to a 10 percent decline in overall accounts over that period.¹¹⁵ Further, PNG-West submitted that it faced much higher risk than FEI, the benchmark utility, with respect to market demand and throughput. PNG-West's total system throughput declined by 87 percent over the 2003-2012 time frame.¹¹⁶ There is no evidence on the record of this proceeding that YEC has encountered a similar situation or will encounter a similar situation over this test period. In the Board's view, this reduces the comparability of PNG-West to YEC; therefore, the Board finds that PNG-West is not a strong comparator to YEC.

4.8.4.3 Comparability to AEY

272. YEC has argued that overall it is a small, northern utility (similar to AEY) but also carries much higher risks relative to AEY in terms of generation, industrial load and by being the main transmitter and generator on an isolated northern grid.¹¹⁷ Table 2.1 of the application¹¹⁸ shows that for the 2017 forecast year, industrial sales represent almost 10% of YEC firm sales, and wholesale sales represent almost 80 percent of YEC firm sales. In terms of risk premium, relative to the BCUC benchmark utility, the Board gives some weight to YEC's lack of customer diversity but notes this item is mitigated by wholesales to AEY (similar to the City of Kelowna and FortisBC [Electric]¹¹⁹) and YEC's use of PPAs with respect to its industrial customers. Further, in BCUC Decision G-47-14, the BCUC determined that what separates FortisBC (Electric) from the Benchmark is its heavy reliance on one industry.¹²⁰ There is no evidence in this proceeding that YEC's industrial load relative to its total firm load is greater or lesser than FortisBC (Electric)'s reliance on one industry.¹²¹

273. In terms of energy price competitiveness, YEC has stated that for new home construction, most builders are using electric heat instead of oil because baseboard heating is a lot simpler and lower cost for the contractor.¹²² Also, due to changes in the regulatory forum around installing

¹¹⁴ Board Order 2017-01, Appendix A: Reasons for Decision, page 44, paragraph 219, PDF page 45.

¹¹⁵ YUB-YEC-1-52, Attachment 3, BCUC Decision G-47-14, decision pages 110, 111, PDF pages 1330-1331.

¹¹⁶ YUB-YEC-1-52, Attachment 3, BCUC Decision G-47-14, decision page 111, PDF page 1331.

¹¹⁷ YUB-YEC-1-56 (b), PDF page 214.

¹¹⁸ YEC application, page 2-17, Table 2.1, PDF page 46.

¹¹⁹ YUB-YEC-1-52, Attachment 3, BCUC Decision G-47-14, decision page 81, PDF page 1301.

¹²⁰ YUB-YEC-1-52, Attachment 3, BCUC Decision G-47-14, decision page 80, PDF page 1300.

¹²¹ YUB-YEC-1-52, Attachment 3, BCUC Decision G-47-14, decision page 80, PDF page 1300.

¹²² Transcript Volume 3, June 28, 2018, page 604, lines 9-18, PDF page 173.

heating oil tanks, the costs for that type of heating have increased materially making electric (heating) cheaper and easier.¹²³ The evidence on the record of this proceeding indicates that YEC faces limited energy price competitiveness. As a result, the Board gives little weight to this factor when assessing a risk premium.

4.8.4.4 Generation Risk

274. In terms of risk of supply, YEC stated its position in terms of generation risk as follows:

Mr. Chair, my understanding from the historical record just generally is that, as the -- as a generator, you're considered to have more risk relative to those utilities that do not have generation. That's our general understanding of that rule.¹²⁴

275. Further, YEC stated:

Q. What I'm trying to understand is how does the generation risk impact on the ROE and the premium that YEC is asking for?

A. MR. OSLER: At a very simple level, using BCUC as the reference point for the benchmark and the examples from BCUC experience of other utilities, our understanding in simple terms is that you can distill the risks down to the size relative to the benchmark utility and the degree to which it has generation as a major component compared to the benchmark utility, which has none. In that context, YEC qualifies as being both small and remote and isolated, but also as a very large scale amount of generation and that it supplies to itself, relative to, say, the comparator utilities, both the benchmark and the because Fortis Electric, which I always keep calling West Kootenay.

Q. Maybe I can rephrase it. Does loss of generation have a direct impact or correlation to -- to revenue?

A. MR. MOLLARD: Well, I'm -- yes. I mean, it will affect profitability to the extent that -- not so much on the revenue side. As my colleague said, we have generation, we plan our generation so that we're able to continue service under a variety of conditions. That said, if there's some event, we have to -- we have to fix that issue, whatever it is on the generation side, and that's -- for a generating utility, there's a lot more risk around, as I said, those complicated machines than there is on our poles and wire system. So our loss of generation is a loss of income -- or not a loss of income, but it will affect me financially.¹²⁵ (underlining added)

276. YEC applies reliability criteria in its capacity planning. YEC stated the following:

A. MR. SRECKOVIC: Okay. Mr. Chair, I would -- I would like to provide some context to the question. No generation facility is reliable 100 percent, so we -- we simply cannot rely on something that will be functioning all the time at the -- at the installed capacity. So to account for lack of reliability, we have to create certain planning reserve. And Yukon Energy uses two criteria to determine planning reserve, and one is called N minus one, the other one is called LOLE.

¹²³ Transcript Volume 3, June 28, 2018, pages 604, 605, lines 19-2, PDF pages 173, 174.

¹²⁴ Transcript Volume 3, June 28, 2018, page 585, lines 9-14, PDF page 154.

¹²⁵ Transcript Volume 3, June 28, 2018, pages 585-586, lines 19-23, PDF pages 156, 157.

I would like first to talk about the L minus criterion. It is a fairly simple criterion that says that the system has to provide enough capacity to serve the load if the greatest unit in the system fails. That unit could be a power plant, transmission line; the greatest unit. For the particular system in the Yukon, it is either the Aishihik power plant or the Aishihik transmission line.

...

So the N-1 criterion is criterion that is used to determine capacity reserve, and N-1 means that -- means a failure of the biggest unit in the system. In our particular system, it is either Aishihik transmission line or Aishihik power plant. Would you like me to talk about the other criterion?

Q. Yes, please.

A. LOLE. The other criterion is called LOLE, and it is also used to provide a capacity reserve. And that criterion takes into account probabilistic reliability of every single unit in the system -- generators, transmission lines too. And -- and it is an industry-wide accepted criterion, and it tells that -- that we should provide reliable service all year long, except up to two hours per year. So it's a probabilistic criterion that says we would have enough capacity to provide electricity to all the hours of the year except up to two hours per year. And that criterion is determined by a sophisticated mathematical calculation, and by doing so, we also get capacity reserve. And in our particular system, the N-1 -- the capacity reserve determined by using the N-1 criterion is greater than the capacity reserve determined by the LOLE criterion. And one of the basic engineering principles is to use more conservative criterion, so we use N-1 to determine our capacity reserve in capacity planning.

Q. Thank you. Now, in using the N-1 criteria and looking at generation risk, does using or applying the N-1 reduce the risk of generation failure or compensate for it? I'm just trying to understand in applying the N-1 criteria, what is the result? Is it that it reduces the risk of generation failure, or it compensates for that failure?

A. MR. SRECKOVIC: It -- it -- it compensates for -- for that failure. Actually, applying -- Mr. Chair, applying that capacity reserve will not reduce our risk of failure. Risk of failure is a function of particular units. Hypothetically speaking, an older unit that is not properly maintained will have a greater frequency of failure. So we use capacity criterion to simply compensate for the failure of -- of units within the system.

A. MR. OSLER: But in terms of the overall business, these are requirements for running the system, and they reflect the type of risk profile we've had throughout all the previous GRAs, just to be clear.¹²⁶ (Underlining added)

277. The Board recognizes the supply risk faced by YEC but notes that, based on the above-noted definition of risk (risk to cash flow), this risk is mitigated through YEC's use of its LOLE and N-1 capacity planning criteria. The Board acknowledges that units used to satisfy the N-1 criteria have a higher output cost (cents/kW.h) relative to hydro generation, and therefore, there is some impact on cash flows. However, the resultant additional assets required to satisfy the capacity planning criteria to an extent mitigate YEC's isolated grid and generation risks.

¹²⁶ Transcript Volume 3, June 28, 2018, pages 590-592, lines 4-23, PDF pages 159-161.

278. For operating risk, the BCUC recognized that generation was a risk but did not give it any weight as there was no basis to measure the potential impact on future cash flows. For Yukon, the Board recognizes this operational risk but also recognizes the mitigating factors discussed in relation to supply risk.

279. The Board is of the view that the remaining risk factors are minor and are compensated through YEC's increased equity thickness relative to the BCUC benchmark utility FEI.

4.8.4.5 Risk mitigation through the DCF

280. It was CW's position that the shifting of risk to customers due to the DCF should result in a lower ROE for YEC.¹²⁷

281. YEC responded:

From the late 1980s, it has been understood by all stakeholders, and more specifically the Board, that the risk of low water conditions (as regards added costs for thermal generation) is to be borne by the customers of the utility. A reserve or deferral account mechanism to implement this risk assignment has been in place since that time. Further, the existence of such a reserve has never been suggested by any stakeholder as a basis to justify a lower ROE nor has the Board ever considered it as a basis for a lower ROE.¹²⁸

282. In this proceeding, the risk premium range before the Board is zero basis points as recommended by CW to 57 basis points as requested by YEC. The midpoint of that range is 28.5 basis points. The Board makes its determination with respect to rate stabilization measures in Section 4.9 of this decision. However, even though YEC has existing rate stabilization measures, CW has not provided sufficient evidence on how it developed its recommendation that the existence of such risk stabilization measures warrant a reduction in the risk premium to YEC by 57 basis points. Therefore, the Board is not prepared to reduce YEC's risk premium by the 57 basis points at this time.

4.8.4.6 Approved risk Premium

283. Based on principles developed in Decision 2017-01¹²⁹ and in terms of risk premium relative to the BCUC benchmark utility (FEI), the Board awards YEC 25 basis points for its small size. Further, in recognition of YEC's risks for generation, isolated grid and customer diversity, the Board awards YEC an additional 20 basis points for a total risk premium of 45 basis points above the BCUC benchmark utility. The Board finds that the additional 20 basis points acknowledges the overall risk of YEC as being greater than that of FortisBC (Electric) and greater than that of AEY. The Board does not accept the 57 basis point premium requested by YEC, because the Board, based on the evidence in this proceeding, does not accept PNG-West as an appropriate comparator to YEC. The Board considers, relative to the BCUC benchmark, that a 45 basis point risk premium for YEC is fair and reasonable.

¹²⁷ CW Evidence, page 12, Q&A 22, PDF page 13.

¹²⁸ YEC Rebuttal Evidence, page 8, section 5.2.1, PDF page 10.

¹²⁹ Board Order 2017-01, Appendix A: Reasons for Decision, AEY 2016-2017 GRA, April 27, 2017, page 40, section 8.1.4.3 starting at paragraph 202, PDF page 41.

4.9 Stabilization mechanisms

284. In its application, YEC identified two mechanisms to stabilize rates and revenues, as follows:

- Rider F
- Diesel Contingency Fund (DCF)

285. The two stabilization mechanisms were discussed in the application in Section 3.6 and Appendices 3.4 and 3.5.

4.9.1 Rider F

286. Rider F is the deferred fuel price account established by Section 8 of *Order-in-Council* 1995/90. Rider F captures all variations in fuel price per litre for each litre consumed compared to those prices approved in the most recent GRA. The Rider F account is also credited with all variations (positive or negative) in the ongoing adjustment to the process of secondary sales compared to the most recent GRA-approved price.

287. For this application, YEC is proposing to revise Rider F to include pricing related to the delivered cost of LNG effective January 1, 2017. Specifically, YEC is requesting the following approvals:

- To defer to the Diesel Fuel Price Variance Account (DFPVA) the variance (plus or minus) in the actual delivered cost of LNG compared to the delivered cost of LNG included in the most recent General Rate Application.
- To include deferred LNG price variances in the amounts collected (or refunded) to customers through the Rider F - Fuel Adjustment Rider & Deferred Fuel Price Variance Policy (Rider F Policy).
- To adjust the Rider F Policy to incorporate reference to LNG pricing in the Diesel Contingency Fund.¹³⁰

288. The UCG opposed YEC's request for changes to Rider F on the basis that:

... the proposed adjustments to the Rider F Policy to incorporate reference to LNG pricing in the Diesel Contingency Fund without: (1) knowing what the actual adjustments are going to be; (2) allowing all parties (including AEY) an opportunity to comment on those adjustments; and (3) having Section 8 of the Rate Policy Directive Order in Council 1995/90 changed to account for LNG.¹³¹ (underlining removed)

289. The UCG noted a decision from the Hawaii Public Utilities Commission wherein the regulator modified the utility's automatic fuel cost surcharge to include a risk sharing element.

¹³⁰ YEC application, page 3-24, section 3.6.1, PDF page 72.

¹³¹ UCG final argument, page 24, paragraph 164, PDF page 25.

The UCG submitted that a similar capping of risk sharing to protect YEC from significant unanticipated increases in fuel prices is warranted.¹³²

290. YEC disagreed with the UCG position. YEC replied that Section 3.6.1 of the application sets out the actual adjustments proposed to incorporate reference to LNG delivered cost pricing in the existing Rider F mechanisms. YEC added that all parties, including AEY, have had opportunity since the application was filed to ask questions and comment on the proposed adjustment as set out in the application. YEC submitted that:

There is no need to have Section 8 of the Rate Policy Directive Order in OIC 1995/90 changed to account for LNG in order to proceed with the proposed adjustment as set out in Section 3.6.1 of the Application. Section 8 of OIC 1995/90 provides direction as to a requirement for adjusting diesel fuel prices and does not in any way inhibit the Board from including in Rider F mechanisms additional LNG fuel price adjustments. By way of example, the Rider F mechanisms currently also accommodate ongoing adjustments to the secondary sales rate.¹³³

291. On the UCG suggestion for a risk sharing mechanism for changes in fuel prices, YEC responded that:

UCG has tabled no substantive evidence to suggest how a fuel price risk sharing would work specifically in Yukon. Given this lack of evidence or even the essence of a framework for implementing this change, YEC has to conclude there is no merit to this proposal today.¹³⁴

Views of the Board

292. The Board finds reasonable the YEC request to defer variances with respect to LNG prices to the DFPVA and to include deferred LNG price variances in the amounts collected (or refunded) to customers through Rider F because the addition of a different thermal fuel is not contrary to the purpose of this deferral account. Rather, it is consistent with the reasons for establishing such a deferral account. The Board, for similar reasons, finds reasonable and approves YEC's request to incorporate references to LNG pricing in the Rider F policy.

293. Lastly, YEC has stated it will assume all risk with respect to the thermal fuel mixture (LNG versus diesel). Therefore, the Board directs YEC to ensure that any variances due to changes in the thermal fuel mixture (forecast versus actual) are not included in the DFPVA. YEC is to indicate, in its compliance filing to this application, the steps it will take to prevent changes in the thermal fuel mixture from appearing in the DFPVA.

294. The Board rejects the submissions of UCG on this issue because there is no evidence in this proceeding that a fuel price risk sharing mechanism such as the one referred to in Hawaii could work in Yukon. Matters that are raised for the first time in argument and which are not

¹³² UCG final argument, pages 23, 24, paragraphs 155, 157, PDF pages 24, 25.

¹³³ YEC reply argument, page 15, section 3.6.1, PDF page 18.

¹³⁴ YEC reply argument, page 15, section 3.6.1, PDF page 18.

based in evidence are not of assistance to the Board and not fair to other parties to the proceeding.

4.9.2 Diesel contingency fund (DCF)

295. The DCF was established as part of a negotiated settlement with respect to the 1996/97 GRA. The purpose of the fund is to have utility ratepayers, rather than YEC shareholders, pay for or benefit from changes to grid diesel generation due to fluctuations in grid hydro generation due to water condition changes that are beyond the utility's control.¹³⁵ YEC's discussion of the DCF is found in the application at pages 3-24 to 3-26 and in Appendix 3.4.

296. YEC stated that its annual thermal generation expense for revenue requirement purposes is determined based on LTA hydro generation, rather than actual hydro generation resulting from actual water conditions. Total thermal generation expense for each year is determined at year-end based on the LTA thermal generation requirement for that level of actual firm generation as determined by the rules established in the DCF Term Sheet as approved by the Board. The LTA estimate for any specific level of firm generation is determined by reference to the relevant table in the approved DCF Term Sheet.¹³⁶

297. The Board, in correspondence dated March 7, 2016, determined it would not address the inclusion of LNG costs in DCF determinations until such time as YEC came forward with a full Rate Rider application or a GRA. The Board approved the reinstatement of Rider E on an interim basis until such time as the 2015 and forward amounts for the DCF are finalized. In this application, YEC sought final approval of DCF amounts for the years 2015 and 2016.¹³⁷ The Board made final determinations¹³⁸ on the Energy Reconciliation Adjustment (ERA) amounts for the years 2012-2016. Finalizing the ERA amounts effectively finalized the DCF amounts for 2015 and 2016.

298. In this application, YEC has requested Board approval with respect to incorporating LNG in annual DCF determinations, an update to the DCF Cap and the 2016 DCF Annual Filing.

299. YEC discussed updates for expected LTA thermal generation in Appendix 3.4 of its application at pages 3.4-2 to 3.4-7. Highlights of those updates include:

- AEY's Fish Lake Hydro.
- YEC's wind generation.
- YEC's hydro generation forecast based on YECSIM modelling with water year records increased to 35 years from the previous use of 28 years. Reservoir and generation water flow requirement changes were also included. Expected thermal generation is provided in Table 3.4-1 of Attachment 3.4-1 assuming mine loads

¹³⁵ YEC application, page 3-24, section 3.6.2, PDF page 72.

¹³⁶ YEC application, page 3.4-1, Appendix 3.4, section 1.1, PDF page 100.

¹³⁷ The final DCF amounts are included in Appendix 3.5 of the application.

¹³⁸ Board Order 2018-05, YEC Part 1: Application Regarding the Energy Reconciliation Adjustment (ERA), issued May 4, 2018.

connected as forecast in the GRA. YEC said it would provide an updated Table 3.4-1 in the future to address material changes in LTA hydro system capability due to changes in loads, installed capacity, licensing/permits or other factors.

- Inclusion of the LNG units as part of the LTA thermal generation forecast including:
 - Capability of LNG in any year to supply the expected LTA thermal generation requirement.
 - Actual LNG use in the year.
 - LNG fuel cost per kW.h to be used for DCF cost assessments.
- The assumed thermal generation mix is 90 percent LNG and 10 percent diesel.
- 2015 DCF determinations used an assumed LNG thermal generation of 15 percent; the 2016 DCF determination used an assumed LNG determination of 100 percent.
- Fuel costs for LNG were set at actual average LNG fuel costs for LNG generation in each year (18.83 cents/kW.h for 2015 and 18.17 cents/kW.h for 2016). For 2017-18 forecasts, LNG fuel costs are 14.67 cents/kW.h. With a forecast diesel fuel cost of 26.33 cents/kW.h, the forecast blended fuel cost is 15.82 cents/kW.h.

300. In response to YUB-YEC-1-5(a) from the YEC Part 1 ERA proceeding, YEC provided an example on page 3 that showed that during different conditions, YEC would have final diesel generation costs for the year according to expected LTA diesel generation for the given load as estimated using the DCF term sheet. However, activities by operators in any fiscal year, such as enhancing winter storage and changes due to actual system operations, could impact the actual diesel generation for that year and could affect the diesel generation amount transferred into or out of the DCF. In response to the (b) part of the question, YEC confirmed that payments into or out of the DCF in any year can potentially be affected by items other than changes in forecast water levels.

301. AEY has argued:

... that the extensive record in relation to both the DCF and ERA is reflective of their complexity and demonstrates that the mechanisms are beyond what is appropriate or necessary for the Yukon regulatory setting and by adopting these mechanisms on a permanent basis into the Yukon utility framework will result in a continued significant burden on administrative and regulatory resources into the future.¹³⁹

302. AEY added that the applied for fuel parameters in this application can mask the potential of these mechanisms to result in significant material DCF and ERA transactions. AEY requested

¹³⁹ AEY final argument, page 1, paragraph 5, PDF page 2 as taken from paragraph 5, the final argument of AEY/YEC Part 1 Application regarding the ERA.

that the Board direct any future ERA payments from AEY to YEC be made payable as the amount is collected from ratepayers.¹⁴⁰

303. CW was of the view that the DCF was poorly defined and appeared to create a potential that it could be used to offset management decisions. CW added that, as a deferral account, it transferred risk from YEC to customers and if it is loosely defined, the utility's risk profile is reduced. Absent more strict or precisely defined rules governing the DCF, CW's view is that the 2017 and 2018 ROE should be reduced. CW did not dispute that the DCF should be funded by customers insofar as it allocates diesel generation when water levels are low. However, CW recommended that YEC be directed in its compliance filing to include a definition and guidelines for its DCF such that funds are only able to be withdrawn in the case of low water levels. Alternatively, CW submitted that if the DCF remains as is, then the ROE awarded to YEC should be reduced by 57 basis points.¹⁴¹

304. Mr. Maissan made the following recommendations:¹⁴²

- That the Board order YEC to use LTA water forecasting for the purpose of determining LTA thermal generation requirement for the DCF calculations and thereby stabilize rates as much as possible.
- That the Board order that the DCF cap (positive and negative) be increased to \$16 million effective immediately.
- That the Board order YEC to bring forward at its next GRA a more thorough analysis on a range of potential DCF caps for discussion and decision at that time.

305. The UCG recommended that the DCF and ERA be eliminated and any current balances of the DCF in excess of \$8 million be credited back to 2017 and 2018 revenue requirements and that the \$8 million contingency balance be maintained.¹⁴³

306. It was UCG's understanding that any deviation between the expected thermal generation costs at LTA availability and actual thermal generation costs (at approved GRA fuel prices) are attributed to the DCF, and there doesn't actually appear to be any difference to YEC to using a short-term forecast or a long-term average forecast as long as there is consistency with forecast and year-end reconciliations.¹⁴⁴ UCG identified concerns with the DCF such as intergenerational equity as well as the split of diesel/LNG.¹⁴⁵

¹⁴⁰ AEY final argument, pages 2, 3, paragraphs 7, 14, PDF pages 3, 4.

¹⁴¹ CW final argument, pages 13-15, paragraphs 47-53, PDF pages 14-16.

¹⁴² Mr. Maissan final argument, pages 3 and 6, PDF pages 4 and 7.

¹⁴³ UCG final argument, page 5, paragraphs 22, 23, page 6.

¹⁴⁴ UCG final argument, pages 17, 19, paragraphs 112, 123, PDF pages 18, 20.

¹⁴⁵ UCG final argument, page 19, paragraph 130, PDF page 20.

307. An adjustment to Rider E was requested by YEC in the application. The UCG noted that due to the passage of time, that request was no longer valid and that YEC should provide an update to the DCF reflecting 2017 actuals for review and determination of a new Rider E.¹⁴⁶

308. UCG submitted “that the way that YEC operates the DCF does not send the right message to ratepayers regarding how they use their electricity when the costs to generate are increasing. UCG submits that ratepayers would immediately conserve (and thus reduce the need for additional generation) if they knew and understood that using more would result in a significantly higher cost to them.”¹⁴⁷

309. UCG further went on to argue that YEC’s use of BC Hydro as an example of a jurisdiction that supports a DCF-type mechanism was incorrect and therefore recommended that the DCF be eliminated and YEC be directed to apply for rate adjustments when it and its shareholder believe that Yukon ratepayers should be asked to pay more when established budgets are being exceeded.¹⁴⁸

310. YEC argued that:

These key provisions¹⁴⁹ related to water risk assignment and long-term rate smoothing reflect normal principles for rate setting for hydro generation utilities in Canada as well as YEC filings and Board decisions on GRA-related matters for Yukon Energy since 1989.¹⁵⁰ (footnotes removed)

311. YEC submitted that:

Where feasible, the DCF also addresses all potential operational risks that could affect thermal generation risks.

The DCF removes specific non-water-related thermal operation risks, e.g., risks related to Reserve for Injuries and Damages (RFID) events, capital projects, thermal unit fuel efficiencies and (as proposed for the first time in the present application) thermal generation maintenance and run-up requirements.

YEC is not aware of any consistent and reasonable way to isolate additional items such as operation risks related to use of water for hydro generation to the extent that these may impact thermal generation costs. Such isolation has not been attempted in either the earlier Low Water Reserve Fund (LWRF) or the DCF. Further, as noted in the response to YUB-YEC-1-6(b) (ERA Part 1 Application), YEC has well-established systems to monitor its use of available water and is not aware of any material impacts on the effectiveness of LWRF or DCF determinations related to the water management element of its systems’ operation.¹⁵¹

¹⁴⁶ UCG final argument, page 20, paragraph 136, PDF page 21.

¹⁴⁷ UCG final argument, page 21, paragraph 141, PDF page 22.

¹⁴⁸ UCG final argument, page 22, paragraphs 144-149, 152, PDF page 23.

¹⁴⁹ In its final argument, YEC asserts that key provisions such as (1) water variability impacts that affect thermal generation are assigned to ratepayers; (2) load fluctuations between GRAs and related thermal generation costs are borne by the utilities; and (3) the DCF smooths and stabilizes rates over the range of potential different annual water conditions.

¹⁵⁰ YEC final argument, page 8, PDF page 10.

¹⁵¹ YEC final argument, page 10, PDF page 12.

4.9.3 DCF Cap Update

312. YEC provided discussion of the existing DCF cap in its application¹⁵² but did not make any specific recommendation to change the cap.

313. YEC submitted:

The higher grid loads experienced in 2017, and now expected in 2018 and subsequent years, further highlight the potential relevance of increasing the DCF cap at this time.

Yukon Energy accordingly proposes that the DCF cap be increased at this time to +/- \$16 million and that the DCF cap be subject to ongoing review at each future GRA.¹⁵³
(footnotes removed)

314. In reply argument, AEY stated that ERA invoices have the potential to be material and therefore requested that the Board direct any future ERA payments from AEY to YEC be made payable as the amount is collected from ratepayers. This would help mitigate expected future issues with an annual, unpredictable, material ERA cash expense. AEY is particularly concerned that the carrying costs associated with a large cash outlay will be incurred and need to be recovered from ratepayers.¹⁵⁴

315. Mr. Maissan responded to the UCG argument when he stated:

I am open to any improvements to the DCF that the parties and the Board think appropriate, however, in my view the elimination of the DCF will result in a profound instability in power bills (caused by positive and negative variations in the rate rider that will be necessary to enable Yukon Energy to pass the water variability risk on to consumers). I do not believe that this will be in anyone's best long-term interest.¹⁵⁵

Mr. Maissan added that this strongly favors LTA hydro-generation forecasts in rate setting.

316. The UCG disagreed with Mr. Maissan's recommendation to raise the DCF cap to \$16.0 million.¹⁵⁶

317. The UCG further argued that in its application, YEC did not apply for a specific modification to the existing DCF cap of \$8 million. However, YEC had changed its position by asking for approval of a specific \$8 million increase to the DCF cap to +/- \$16 million as well as approval to review the DCF cap at each future GRA. UCG's position is that the DCF and all models used by YEC designed to isolate the impact of water and wind variability from all the other factors that can affect diesel consumption are simply expensive, unaccountable exercises in futility. Accordingly, the DCF should be immediately eliminated to avoid manipulation and unintended uses of the DCF and to put the obligation on YEC to properly budget and live within that budget.¹⁵⁷

¹⁵² YEC application, pages 3.4-9 to 3.3-12, Appendix 3.4, PDF pages 108-111.

¹⁵³ YEC final argument, page 13, PDF page 15.

¹⁵⁴ AEY reply argument, page 3, paragraphs 8, 9, PDF page 4.

¹⁵⁵ Mr. Maissan reply argument, page 1, paragraph 1, PDF page 2.

¹⁵⁶ UCG reply argument, page 7, paragraph 24, PDF page 8.

¹⁵⁷ UCG reply argument, page 12, paragraph 53, PDF page 13.

Views of the Board

318. The Board accepts YEC's submissions that volume of hydro electric generation due to changing water conditions is a factor largely outside the control¹⁵⁸ of management and thermal generation volume may be partially¹⁵⁹ influenced by volumes of hydro electric generation. Also, a utility should neither make a profit nor suffer a loss from variances in forecasting due to water levels. The Board considers that the risk of low water conditions, with respect to added costs for thermal generation, should be borne by the customers of the utility.

319. Given the isolated nature of the Yukon environment, the ramifications that low water events can have on electricity prices and the need to mitigate those impacts, the Board finds that a DCF-type of mechanism is required. The Board agrees with YEC submissions that in Yukon the risks related strictly to low water events have been borne by ratepayers. No evidence has been provided in this proceeding to change the Board's view that ratepayers bear this risk.

320. However, the Board is of the view that the current DCF mechanism is complex and does not show the hydro generation and thermal generation in a given year when actuals are determined because the actuals are based on modelled results. The Board finds that a simpler mechanism for adjusting for variances between the approved forecast for hydro generation and thermal generation and actual hydro generation and thermal generation in a test year is needed. A deferral account is a rate adjustment mechanism aimed at reconciling forecasts with actuals for matters that are not in the control of the utility.

321. For these reasons, the Board directs YEC to create a deferral account that records the variance between actual thermal generation fuel costs (based on volume only) and the GRA forecast thermal generation fuel costs (based on volume only) that are due to changes in water conditions. Factors such as equipment failure, force majeure, capital or planned maintenance events are not to be included in the calculations for this deferral account. YEC is directed, in its compliance filing to this decision, to propose trigger levels (+/-) that will initiate a rider proceeding to dispense with the balance in the deferral account.

322. The difference between the directed deferral account above and YEC's proposed DCF is that the deferral account will be adjusted for those variances between approved forecast and actual, not modelled, results. In other words, the deferral account will be adjusted for changes in hydro generation that are a result of changes in water availability. YEC is directed, in its compliance filing, to explain the method it will use to determine the variance in hydro generation due to water availability. The Board directs that the deferral account be named the Low Water Reserve Fund (LWRF) as it will incorporate a broader range of thermal generation. YEC will adjust the balance in the LWRF on an annual basis for the difference in forecast thermal generation from actual thermal generation based on forecast load and only adjusting for the changes in hydro generation that are a result of changes in water availability.

323. To draw from the LWRF due to low water levels, YEC will have to submit an application to the Board requesting a drawdown of the fund indicating that the application is due to changes

¹⁵⁸ Operational decisions that influence the level of hydro generation are within the control of management.

¹⁵⁹ Levels of thermal generation are also influenced by operational decisions and customer load.

in hydro generation because of changes in water levels from those contained in the last Board-approved forecast. YEC will take the forecast risk for incremental generation costs for incremental loads outside of the forecast period with the exception of incremental load covered by the ERA.¹⁶⁰ YEC is directed to amend its DCF term sheet to comply with these directions. Conversely, when the fund requires replenishment, YEC can apply to the Board for rate rider to replenish the LRWF. YEC, in its compliance filing, may submit any potential ceiling for the LRWF rate rider.

324. YEC's DCF is currently at or around its cap of \$8,000,000. This balance in the DCF is to be transferred in its entirety to the LRWF. The Board is not persuaded by the submissions of parties that a change in the cap is required because to date it has not been used to refund customers, and customers would have to wait longer for such refunds if the cap was increased. This would not be a fair outcome.

325. YEC is directed, in its compliance filing to this decision, to provide further details on how this LRWF will operate.

5 Rates

326. YEC has proposed changes to the following rider:

Rider J – Yukon Energy Revenue Shortfall Rider - Applicable to all YEC and ATCO Electric Yukon (AEY) firm retail rates (all AEY recoveries from this rider would flow through to YEC) and industrial rates. The existing Rider J is 11.01% for non-industrial rates and 7.36% for industrial rates. The Rider J increase to each existing Rider J to recover the application revenue shortfalls is 9.04% for 2017 and 2.07% for 2018.¹⁶¹

327. Issues regarding interim rates were determined in Board Order 2017-06.

328. YEC noted that, based on Table 4.1 in its application and assuming the sales forecast included in Section 2 of the application, at existing rates, there would be revenue shortfalls of \$5.348 million and \$6.585 million for each of 2017 and 2018.

329. No structural changes were proposed to any of the existing rate schedules.

330. For the alternative ST forecast, YEC proposed the following for Rider J:

Rider J – Yukon Energy Revenue Shortfall Rider – Applicable to all YEC and ATCO Electric Yukon (AEY) firm retail rates (all AEY recoveries from this rider would flow through to YEC) and industrial rates. The existing Rider J is 11.01% for non-industrial rates and 7.36% for industrial rates. The Rider J increase to each existing Rider J to recover the Alternative GRA Forecast revenue shortfalls is 5.61% for 2017 and 4.31% for 2018.¹⁶²

¹⁶⁰ See the subsection on wholesale rates in section 5.

¹⁶¹ YEC application, page 4-1, lines 13-17, PDF page 150.

¹⁶² YEC ST alternative application, page 4-1, lines 13-17, PDF page 150.

331. YEC noted in its ST forecast that, based on Table 4.1 and assuming the sales forecast included in Section 2 of the ST updated application, at existing rates, there would be revenue shortfalls of \$3.320 million and \$5.881 million for each of 2017 and 2018. YEC provided an updated sales forecast in Undertaking 35 that reflected 2017 actual sales. The update shows a revenue shortfall of \$5,616,000 for 2017.

332. No structural changes were proposed to any of the existing rate schedules.

333. In response to CW-YEC-1-31, YEC confirmed that it was not proposing any Phase II rate adjustments in its application nor any changes to the Terms and Conditions of Service.

5.1 Secondary Sales

334. The UCG argued that, due to secondary sales rates being lower than firm rates, customers that are part of the secondary sales program have an unfair advantage over their competitors and that YEC should provide an analysis of this.¹⁶³

335. YEC responded that secondary sales are interruptible, that secondary sales customers must have a proven alternative fuel supply and the secondary sales rate is set at a fixed percentage of alternative fossil fuel market costs.

Views of the Board

336. The Board accepts YEC's above-noted reasons for secondary sales rates being lower than those of firm customers. The Board requires no further action from YEC on this issue for this application.

5.2 Wholesale Rates

337. AEY presented arguments on the ERA aspect of rate schedule 42. AEY requested that the Board direct that any future ERA payments from AEY to YEC be made payable as those amounts are collected from ratepayers.¹⁶⁴

338. The UCG position with respect to wholesale rates also pertained to the ERA and submitted that without a comprehensive review of a cost of service study, the Board cannot determine the proposed wholesale rate and ERA component of that rate. The UCG recommended that the ERA be eliminated.¹⁶⁵

339. YEC replied that AEY's position is without merit as YEC is the party who incurs the ERA costs and is entitled to its recovery on a timely basis. In addition, YEC contended that AEY has already recovered the added rate revenues associated with any increased sales that resulted in a year-end ERA charge and accordingly enjoyed the related cash surplus associated with such incremental retail sales.¹⁶⁶

¹⁶³ UCG final argument, page 14, paragraphs 89-91, PDF page 15.

¹⁶⁴ AEY final argument, page 3, paragraph 14, PDF page 4.

¹⁶⁵ UCG final argument, page 25, paragraphs 165-172, PDF page 26.

¹⁶⁶ YEC reply argument, page 22, section 4.3, PDF page 25.

340. With respect to UCG, YEC noted that a cost of service study focuses on costs and revenues for each retail and industrial firm customer class of AEY and YEC and ignores the requirements of OIC 1995/90.¹⁶⁷

Views of the Board

341. The Board accepts the submissions of YEC on wholesale rate matters. The UCG submissions ignore the requirements of OIC 1995/90 and is therefore rejected by the Board. The AEY position of paying YEC ERA amounts as it collects those amounts from customers lacks detail as to how such a process would be implemented and is also rejected by the Board. Given the Board's determinations with respect to the LWRF, YEC is directed to amend the ERA portion of Rate Schedule 42 to ensure it is in compliance with those directions.

342. To be clear, ERA billing or refund amounts will be based on a consistent definition of costs. In this decision, the Board has clarified that actual costs for both the LWRF and the ERA are those costs related to actual thermal generation and not forecast thermal generation. Further, if significant industrial load enters or leaves the Yukon Integrated System or there are material changes in generation assets where either or both of these factors change the baseload generation mix, YEC can propose changes as to how the LWRF and the ERA operate at that time.

343. YEC is directed to make the changes requested in this section in its compliance filing to this decision.

5.3 Other Rate Matters

344. The UCG lists in its final argument the following rate-related matters¹⁶⁸:

- Only existing base rates should apply after the Board makes its determinations on YEC's 2017-2018 GRA until the completion of a Phase II process. A variance account would need to be established to record any variance in collections from approved totals.

As a penalty for late filing of the application, there should be no recovery of any foregone revenue from January 1, 2017 to the date on which the YUB approves rates following the compliance filing.

- AEY and YEC should be directed to file sometime in Q1 2019 a Phase 2 application based on revenue requirements approved for 2017 and that the utilities should be directed to involve stakeholders in consultations.
- The Yukon Government and not non-industrial ratepayers should be held liable for any revenue deficiency in the event the Phase 2 review indicates that industrial rates do not recover their full costs.

¹⁶⁷ YEC reply argument, page 22, section 4.3, PDF page 25.

¹⁶⁸ UCG final argument, pages 4, 5, 91-96, 98-100, paragraphs 13-17, 625-639, 640-657, and 661-67, PDF pages 5, 6, 92-97, 99-101.

- There is no benefit or useful purpose to providing evidence that compares Yukon electricity bills with electricity bills in other jurisdictions that operate under completely different political, utility and business environments.
- There is no reason that performance-based regulation or an incentive regulation mechanism could not be considered for Yukon following the completion of a Phase 2 review.

345. YEC replied that most of UCG's positions on other rate-related matters are without merit and beyond the scope of the 2017-2018 GRA. YEC added that several of the UCG requests have no basis for the Board under the *Public Utilities Act* or normal regulatory principles consistent with OIC 1995/90.¹⁶⁹

View of the Board

346. The Board finds that these issues brought forward by UCG are outside of the scope of this proceeding and not helpful to the Board's determinations on the issues contained in the application. Further, UCG did not advance any evidence in support of these submissions and has not shown these submissions to be in accordance with the *Public Utilities Act* or OIC 1995/90.

6 Capital projects

6.1 Capital projects

347. YEC submitted that its rate-base growth of \$64.9 million over 2013 approved costs reflects \$45 million net increase from two major capital projects related to capacity planning requirements and \$25.4 million from eight sustaining capital projects.

348. Total spending on property, plant and equipment (PP&E) in the test years is forecast at \$14.605 million in 2017 and \$14.633 million in 2018, with 64 percent of that on major projects. YEC submitted that this represents a lower average spending level than occurred between 2013 and 2016 and that annual spending on capital works peaked in 2010/11.

349. Deferred-cost capital spending is forecast at \$5.6 million in 2017 and \$17.6 million in 2018, an increase from the average of \$4.9 million for each year from 2013 to 2016.

350. Approximately \$13.9 million in deferred costs for feasibility studies, 2016 Resource Plan, DSM and other projects is proposed to be brought into rate base as of January 1, 2017. An additional \$6.3 million of earlier deferred overhaul costs are proposed to be brought into the PP&E capital works rate base as of January 1, 2017.

351. This section reviews:

¹⁶⁹ YEC reply argument, pages 24, 25, PDF pages 27, 28.

- a. Major projects (projects greater than \$1 million) undertaken by YEC since the 2008-09 GRA and those projects planned for the 2017 and 2018 test years.
- b. Ongoing capital projects costing between \$100,000 and \$1 million that are forecast to occur over the 2017 to 2018 test period.

352. With respect to a number of YEC's capital projects, UCG noted that in Order 2013-01, the Board identified YEC's commitment to seek Board approval prior to carrying out capital projects costing \$3 million or more and to YEC's admission that the only way to initiate a review of a capital project is through a GRA. The UCG also submitted that, pursuant to Board Order 2009-8 and 2013-01, business cases are required for major projects.

353. UCG stated that a number of YEC's projects were "...not mentioned in YEC's 2012/2013 GRA and has not been included in YEC's Resource Plan..."¹⁷⁰ and that when asked to provide a business case analysis, YEC was unable to provide detailed information. The UCG added that this is a \$10 million project that must be reviewed by the Board prior to it being initiated. For these reasons, UCG submitted that YEC presented insufficient evidence to justify the timing of these projects and recovery of associated expenses from ratepayers. Therefore, YEC and its shareholders should be held accountable for all costs related to these projects.¹⁷¹

354. YEC did not reply to these on a project-by-project basis but instead responded more generally, as follows:

Further, contrary to UCG's argument, YEC has provided business cases for all major capital and deferred cost projects in excess of \$1 million as directed by the Board, and parties have had ample opportunity in this proceeding to question and examine these business cases¹⁷²

...

UCG's broad and repetitive assertions to disallow costs from test year rate base for the eleven major capital projects in the Application are without merit or usefulness to the Board. The extensive review allowed in the current proceeding confirms that UCG had ample opportunity to obtain relevant information that could assist the Board and it is simply not credible to now assert in argument that the information for every one of these projects was inadequate because YEC did not respond to all of UCG's wide ranging information requests.¹⁷³

Views of the Board

355. Contrary to UCG's assertions, a project need not be approved by the Board prior to being initiated because YEC is at risk for the costs of a project if the Board, when YEC requests approval of the capital costs to be included in rate base, determines that the costs related to a project are unreasonable or not prudent.

¹⁷⁰ UCG final argument, paragraph 246, PDF page 39

¹⁷¹ UCG final argument, paragraphs 252, 255, 259, 263, 267, 271, 275, 279, 283 and 313.

¹⁷² YEC reply argument, page 28, section 5.2, PDF page 31.

¹⁷³ YEC reply argument, page 31, section 5.3, PDF page 34.

356. The Board also notes that, in Undertaking 35, YEC noted that mid-year net rate base is within 0.2 per cent of the GRA forecast.¹⁷⁴ However, YEC did not provide 2017 actuals for capital costs on a project-by-project basis. Accordingly, the Board directs YEC to update its costs for each project in the compliance filing to this decision.

6.1.1 Major projects over \$1 million

357. YEC submitted that with the completion of major legacy infrastructure projects, spending on major capital works during the test period is focused on projects required to address sustaining capital requirements and investments to ensure sufficient dependable capacity for the grid. The total cost forecast to be added to net rate base for major projects by the end of 2018 is approximately \$60.4 million (net of contributions of \$18.3 million) with an additional amount of slightly more than \$6 million forecast to come into service in the first quarter of 2019.

358. The following subsections address the major projects over \$1 million included in YEC's application.

6.1.1.1 Project Aishihik Third Turbine

359. The Aishihik hydro facility third turbine came into service in December 2011. Since 2012, YEC has incurred \$2.175 million of costs for wrap-up activities related to the project, including \$2.574 million from a dispute with a project contractor. YEC spent \$2.117 million in 2016, the majority being legal costs to defend the company against legal action resulting from the project. YEC submitted that it will present the total project costs to the Board for review upon final settlement of the lawsuit, which was under appeal at the time of this application. During the oral hearing, YEC indicated that its appeal was successful and that it was working on reaching a settlement with the project contractor.¹⁷⁵

360. In argument, UCG acknowledged that YEC is not applying for these costs in the current test period but submitted that the Board should direct YEC to clearly demonstrate that these costs are not included in any rates to be charged in 2017 and 2018.¹⁷⁶

Views of the Board

361. The Board acknowledges that YEC is not applying for recovery of any costs related to the Aishihik third turbine project in the current test period. Therefore, there is no need to direct YEC to demonstrate that the costs incurred in relation to this project are not included in the 2017 or 2018 requested revenue requirement as requested by UCG. Accordingly, the Board makes no determination on the prudence of the costs of this project at this time.

6.1.1.2 Aishihik Elevator Shaft Structural Steel Rehabilitation

362. In 2011, YEC added a second feeder cable in the Aishihik elevator shaft. Following completion of that project, the Yukon Workers Compensation Health and Safety Board (OH&S) required YEC to have an independent engineer evaluate the installation to ensure the elevator

¹⁷⁴ YEC response to Undertaking 35, PDF page 4.

¹⁷⁵ Transcript Volume 1, June 26, 2018, page 70, lines 9-15, PDF page 70.

¹⁷⁶ UCG final argument, paragraph 216, PDF page 34.

met all applicable codes, acts and regulations. The engineer's report recommended permanent rehabilitation of the structure and imposed a list of conditions on use of the elevator until that work was completed. YEC submitted that there was no reasonable alternative to this project because regular access to the elevator is required for operation of the plant.

363. In its application, YEC stated that this project was completed in June 2017 and had a forecast cost of \$10.116 million, to be added to rate base at the end of 2017 and depreciated over 72 years and broken down as follows:

- a. Engineering and design: \$0.487 million
- b. Construction field costs: \$8.036 million
- c. Construction management: \$1.280 million
- d. YEC owners and financing costs: \$0.313 million

364. During the oral hearing, YEC corrected the life cycle and subsequent depreciation period for this project to 40 years and proposed to reflect that correction in the compliance filing.¹⁷⁷

365. YEC also explained that after the addition of the second feeder cable in the Aishihik elevator shaft in 2011, workers noticed that unprotected cables ran along the floor and up the side of the shaft. A tin shield was put on the cables to protect them, but that led to the elevator car contacting the shield. As a result, OH&S was contacted, leading to the above-noted broader inspection of the elevator and its surroundings and subsequently the shaft rehabilitation project. YEC explained further that there were concerns with the way the cables were fastened to the cable tray, requiring the cables to be re-attached with better clamps.¹⁷⁸

366. In attachment 1 to YUB-YEC-1-63, the independent engineer's assessment anticipated the cost of replacing the cable clamping at \$150,000-\$200,000.¹⁷⁹ During the oral hearing, YEC estimated that work necessary as a result of the 2011 cable installation amounted to less than \$500,000.¹⁸⁰

367. Mr. Maissan recommended that the Board accept the cost of this project and submitted that a 40-year depreciation period was appropriate.¹⁸¹

Views of the Board

368. The Board accepts that this project was driven by the requirements imposed by the OH&S and that it is a project to address safety concerns within the elevator shaft.

¹⁷⁷ Transcript, Volume 1, June 26, 2018, page 19, lines 8-11, PDF page 19.

¹⁷⁸ Transcript Volume 3, June 28, 2018, page 46, lines 11-13, PDF page 477.

¹⁷⁹ Consolidated IR responses (and attachments), PDF page 1623.

¹⁸⁰ Transcript Volume 3, June 28, 2018, page 46, lines 17-19, PDF page 477.

¹⁸¹ Maissan argument, section 13, PDF page 8

369. However, any portion of this project that results from improper work done as part of the 2011 project requires further consideration. As noted by YEC during the oral hearing and in IR responses, some of the work in the current project is to replace the clamps used to mount the cabling, because the clamps used did “not meet modern standards for supporting long runs of vertical rise cable, nor is it appropriate for keeping the cables in place under the significant magnetic forces of a major fault.”¹⁸² In the view of the Board, it was imprudent of YEC, as part of its 2011 project, to use clamps that do not meet modern standards for this use. Accordingly, the Board disallows \$200,000 of the costs for the Aishihik elevator shaft steel rehabilitation project. The Board directs YEC to reflect this direction in its compliance filing to this decision.

370. For the other components of this project, the Board considers that the related costs are prudent and reasonable.

6.1.1.3 Aishihik electrical and control upgrades

371. This project includes a number of control systems and electrical upgrades that YEC submitted are being done to ensure ongoing safe and reliable operation of the Aishihik generating station. Approximately \$2.511 million of upgrades are planned to be completed by the end of 2018, consisting of:

- a. Control system upgrade
 - i. AH1 and AH2 control system replacement - \$1.489 million
 - ii. AH3 control system drawings update - \$0.025 million
 - iii. AH0 turbine inlet valves automation - \$0.190 million
 - iv. Aishihik human machine interface (HMI) installation - \$0.175 million
 - v. Aishihik remote terminal unit (RMU) replacement - \$0.025 million
- b. Electrical upgrades
 - i. Motor control centre (MCC) equipment for AH0 station service - \$0.243 million
 - ii. Aishihik grounding refurbishment - \$0.045 million
 - iii. S167 porcelain insulator change out - \$0.079 million
 - iv. AH reactor cable replacement - \$0.075 million
 - v. AH3 lube oil pump battery installation - \$0.090 million
 - vi. Aishihik blackstart modifications - \$0.075 million

¹⁸² Consolidated IR responses (and attachments), PDF page 1622.

372. Mr. Maissan recommended that the Board approve the Aishihik electrical and control upgrades project as proposed.¹⁸³

Views of the Board

373. With respect to the AH reactor cable replacement, YEC stated that the cables were replaced in 2011 but that the cables are undersized and needed to be replaced. In response to a Board IR, YEC stated that the reactor cable replacement was not part of the original 2011 project scope of work and was the result of a change order caused by design complications. According to YEC, a length of wire removed as part of the project was repurposed for the reactor cable. The wire was deemed to be adequate for an air-free installation but was instead placed in an underground conduit.¹⁸⁴ The Board is of the view that YEC acted imprudently in its 2011 replacement of the reactor cable and that ratepayers should not be asked to pay the costs of fixing work that was improperly done only seven years ago. Accordingly, the Board disallows the \$0.075 million that YEC has proposed to include in its rate base for the AH reactor cable replacement and directs YEC to reflect this in its compliance filing.

374. For the AH3 control system drawings update, YEC stated that this project will review operator interfaces and correct existing drawings to safely operate the equipment in anticipation of a full control system replacement in future years. The full replacement is expected to occur during the next scheduled overhaul in 2021. Although the Board has concerns about whether the deficiencies identified must be corrected prior to the 2021 replacement, if any components of this project are undertaken as discussed below, the AH3 control systems drawing update is needed to ensure the safe and reliable operation of the system. Accordingly, costs related to this component are to be held in WIP, and the Board will consider the reasonableness and prudence of these costs when approval is sought to add the project to rate base.

375. With respect to the Aishihik HMI installation, YEC stated that this project will provide better visibility into plant operating conditions and improve its ability to investigate and troubleshoot plant operating issues. In argument, YEC noted that:

A number of specific control systems and electrical upgrades are being undertaken to ensure ongoing safe and reliable operation of the Aishihik generating station. The need for the project was determined following a formal asset assessment completed by KGS as well as plant inspections undertaken in 2015. These reviews confirmed that many of the electrical and control systems in the Aishihik plant have reached end of life and need to be replaced; existing control systems lack functionality to optimize plant operations; and replacement and upgrading of these controls systems will modernize the interfaces, improve trouble shooting capability, and provide better information on the operating stage of the equipment.¹⁸⁵

376. However, the Board is of the view that YEC could have provided better evidence regarding why the current ability to investigate and troubleshoot plant operating issues is inadequate. Also, YEC could have better demonstrated the benefits to customers of any of the proposed improvements to the Aishihik HMI installation. Notwithstanding the comments on

¹⁸³ Maissan argument, section 14, PDF page 9.

¹⁸⁴ YEC response to YUB-YEC-1-64 (d), PDF page 238.

¹⁸⁵ YEC final argument, page 31, section 3.1.2, PDF page 33.

better evidence, the Board accepts YEC's position that the Aishihik electrical and control upgrades resulted from the asset assessment by KGS and the plant inspections from 2015. Based on that assessment and that inspection, the Board approves the costs associated with the Aishihik HMI installation as requested by YEC.

377. With respect to the Aishihik RTU replacement, YEC submitted that the project will reduce the resources required to monitor and control the three Aishihik units. Again, YEC could have provided better information on any cost savings or other benefits that would result from this reduction in required resources. However, similar to the finding with respect to the Aishihik HMI installation, the Board accepts the submission from YEC that the Aishihik electrical and control upgrades resulted from the asset assessment by KGS and the plant inspections from 2015. Based on that assessment and that inspection, the Board approves the costs associated with the Aishihik RTU replacement as requested by YEC.

378. With respect to the AH3 lube oil pump battery installation, YEC submitted that failure to install this backup installation increases the risk of the AH0 backup battery bank being drawn down too quickly, which could compromise the ability to recover the plant following an extended outage. In response to a Board IR, YEC added that the main battery is designed to last 16 hours, but the additional draw of the lube oil pump reduces that to approximately one hour. YEC added that a one-hour station service outage is unlikely, but the consequences of fully discharging the battery are severe.¹⁸⁶ The Board accepts that the estimated 15-hour reduction in the backup battery bank's ability to service station components is significant and warrants installation of a battery dedicated to the lube oil pump. Accordingly, the Board finds that the lube oil pump battery installation is needed and approves this component of the project. However, before approving the reasonableness of the costs, the Board directs YEC in its compliance filing to provide the 2017 actual costs for this component of the project.

379. With respect to the Aishihik blackstart modifications, YEC stated that the blackstart generator can be improved to take on additional loading to run more efficiently when called into service and that it would be beneficial to increase the number of Aishihik station services served by the blackstart generator. In response to a Board IR, YEC stated that the blackstart generator was installed in 2014 and that this project is partly intended to decrease wear on the asset caused by underloading. YEC added that with the generator being underutilized, there is an increased risk of it not performing during an outage.¹⁸⁷ The Board accepts that this project is necessary to ensure that the newly installed blackstart generator can operate properly and to reduce wear on that generator.

380. The Board has reviewed the other projects included within the Aishihik electrical and control upgrades and finds that they are needed for the continued safe and reliable provision of utility service.

¹⁸⁶ YEC response to YUB-YEC-1-65 (a), PDF page 239.

¹⁸⁷ YEC response to YUB-YEC-1-66 (c), PDF page 242.

381. The Board directs YEC to update its 2017 costs for these projects to reflect 2017 actuals and to reflect the other findings in this section in its compliance filing. YEC, in the compliance filing, is also to indicate when it proposes to add these costs to rate base.

6.1.1.4 Communications upgrades

382. YEC proposed a number of communications networks upgrades to replace end-of-life network infrastructure and implement a simplified network infrastructure to increase performance and improve reliability of the network.

383. In 2016, an independent consultant completed a communications needs assessment and made recommendations to improve critical elements such as supervisory control and data acquisition (SCADA) and to improve network performance, reliability, redundancy and security. The consultant proposed a system design and recommended staged implementation focusing on the most critical assets or initiatives first. Approximately \$1.003 million worth of upgrades are planned to be completed by the end of 2018, as set out below:

- a. Satellite installations for SCADA - \$0.150 million
- b. Network access controls - \$0.035 million
- c. Community servers - \$0.050 million
- d. Fibre communications upgrades - \$0.363 million
- e. SCADA communications upgrades (\$0.405 million in 2018 and \$0.275 million thereafter)

384. In response to a Board IR, YEC indicated that it is seeking approval to put the costs associated with this project into rate base as the work will be completed during the test years and be put into service.¹⁸⁸

385. YEC submitted that loss of communications with YEC operating facilities increases the risk to the overall operation of these assets and the electrical system as a whole.

386. With respect to the satellite installations for SCADA, YEC submitted that this upgrade is a key building block for creation of a fully redundant communications infrastructure as required for enhanced system reliability and efficiency. YEC submitted further that this will allow it to run many new services and protocols to its sites compared to existing serial links. According to YEC, not doing this work will force it to rely on old technology, which is harder to support and will not “scale to meet new communications needs”¹⁸⁹ increasing the risk of service outages.

387. YEC explained that the network access controls project involves implementation of automated network access protocols to control access by any device attempting to access the network and is required to mitigate access risks resulting from new technologies proposed in the

¹⁸⁸ Response to YUB-YEC-1-67, PDF page 244.

¹⁸⁹ YEC application, page 5-13, PDF page 184.

satellite installations for the SCADA project. In the absence of such controls, YEC's communications system would be locked down, with access provided through manual intervention by information technology (IT) staff on a case-by-case basis, compromising the effective delivery of services.

388. According to YEC, the community servers project involves installation of services in YEC's Dawson and Mayo offices to create physical hubs from which IT support can deploy software and provide enhanced computer services. Without this project, IT staff must drive to the affected community or affected hardware would have to be shipped to YEC's head office.

389. YEC explained that fibre communications upgrades involve installing a fiber optic link from the Whitehorse Rapids Generating Station (WRGS) to three substations and will allow for more reliable and flexible communication as well as creating the backbone for a redundant data centre at Takhini substation. During the oral hearing, YEC explained that the redundancy is part of its disaster recovery planning whereby a second set of hardware is available at the Takhini substation in the event that YEC cannot access its head office.

390. With respect to the SCADA communications upgrade, YEC submitted that the current infrastructure uses serial communication, which significantly limits operational flexibility and redundancy.

391. In response to a City of Whitehorse IR, YEC stated that the current communications links to certain sites are "barely large enough to carry essential information" and that the project will allow better analysis and decision making. YEC added that having multiple links to transfer data means that one link can be worked on remotely with no downtime. YEC also indicated that it had not done any specific research on the wants or needs of customers regarding internal communication structure, but that "the Resource Plan Values Survey reported that 71% of respondents indicated they would support a rate increase due to efforts to reduce power outages in their area."¹⁹⁰

392. During the oral hearing, the Board asked YEC to comment on the nature and quantum of risk posed to YEC's infrastructure that would warrant this expenditure to create a redundant data center. YEC responded that its head office is in a high consequence earthquake zone and is right below the Whitehorse dam. YEC was unable to quantify the risk of an earthquake occurring but stated that they felt it prudent to update its disaster recovery planning. YEC added that a "sizeable earthquake" did occur in 2017 and that all of its office space was "wiped out" by a fire in 1997. In the latter case, YEC was able to operate the system manually, but YEC submitted that the system is now at the point where data connectivity with plants is needed to be able to run the system.¹⁹¹

393. Mr. Maissan recommended that the Board approve the communications upgrades project as proposed.¹⁹²

¹⁹⁰ YEC response to CW-YEC-1-37, PDF page 108.

¹⁹¹ Transcript Volume 3, June 28, 2018, pages 458-460, lines 15-15, PDF pages 27-29.

¹⁹² Maissan argument, section 15, PDF page 9.

Views of the Board

394. The Board accepts that communications upgrades to ensure the continued operation of the electrical system in the event of an incident significantly affecting YEC's head office in Whitehorse are warranted. However, the Board examined each of the components of this project to determine whether all of the components are needed.

395. In the application, oral hearing and IR responses, YEC clearly linked the satellite installations for SCADA and fibre communications upgrades to creating redundancy for disaster planning. YEC's application also states that the network access controls are needed due to changes resulting from the satellite installations and that the SCADA communications upgrades will facilitate satellite communication at YEC's various sites. Therefore, the Board finds that the satellite installations for SCADA, fibre communications upgrades and network access controls are necessary as part of YEC's disaster recovery planning and approves these projects. The Board notes that, based on the response to YUB-YEC-1-67, there have been no cost changes since the estimates provided in the BBA assessment.¹⁹³ Nonetheless, the Board directs YEC to include all actual costs for 2017 for all capital projects as part of its compliance filing to this decision.

6.1.1.5 Liquid natural gas (LNG) plant

396. The LNG plant project at the Whitehorse Thermal Generating Station (WTGS) came into service on July 1, 2015, with two natural gas engines and provision for a third natural gas engine. The LNG plant project (also referred to as the Whitehorse Diesel-Natural Gas Conversion Project) involves conversion of WTGS thermal generation units, scheduled for retirement, from diesel fuel to natural gas fuel. The LNG plant project was reviewed by the Board as a supply planning project in the 2012-13 GRA and in the 2014 project-specific review under Part 3 of the *Public Utilities Act*.

397. YEC submitted that the final completion costs of the project were approximately \$41.933 million; however, YDC contributions of \$18.3 million partially offset those costs, reducing the amount funded by ratepayers to \$23.63 million. YEC stated that major project delays and changes were experienced as a result of the Yukon Environmental and Socio-economic Assessment Board (YESAB) review process and the *Yukon Oil & Gas Act* (YOGA) permitting. The new requirements included additional risk assessments and material site layout design changes and resulted in additional costs, contributing to the total costs exceeding the Part 3 hearing estimates by \$5.45 million.

398. The \$5.45 million in increased costs was made up of the following:

- a. \$4.084 million in additional construction costs
- b. \$1.538 million in increased engineering and management costs
- c. \$0.615 million in increased owner costs

¹⁹³ The assessment does not include YEC internal labour. YUB-YEC-1-67(c), PDF page 244.

- d. \$0.182 million in increased planning and permitting costs
- e. removal of \$0.553 million in demolition and removal costs that has been redefined as a post-project construction activity that will be conducted in the future
- f. removal of \$0.326 million in LNG transportation costs and
- g. removal of \$0.09 million in First Nation benefits¹⁹⁴

399. YEC submitted that the YDC contributions of \$18.3 million more than offset the additional costs and, provided that the third LNG engine costs less than \$9 million, the resulting final LNG plant project costs will be less than the 13.4 MW diesel plant option costs of \$32.7 million, as estimated in the Part 3 hearing.

400. In response to a Board IR, YEC provided a breakdown of the cost increases but did not provide any additional description or reasoning for the increases.¹⁹⁵

Views of the Interveners

401. The UCG expressed concern over the cost increases for this project and the third LNG engine (discussed further in Section 6.1.1.6 below). The UCG also highlighted the fact that, during the Part 3 review, YEC characterized the LNG plant as a backup or emergency generator and justified the project partly based on the savings resulting from using LNG for backup instead of diesel. UCG submitted that YEC did this strategically in order to get the LNG conversion project through the initial regulatory hurdles and requested that the Board reconsider how the LNG project was originally justified and correct the original recommendation to approve the Energy Project Certificate and Energy Operation Certificate.¹⁹⁶

402. The UCG referenced the Auditor General's 2005 report on the Mayo-Dawson City Transmission System Project and highlighted the Auditor General's conclusion that YEC's financial management and project cost controls were inadequate. The UCG went on to reference the 2007 Report to the Commissioner in Executive Council on YEC's 20-Year Resource Plan, in which the Board recommended that YEC adhere to all outstanding recommendations in the Auditor General's report and stated that for any subsequent major project, YEC should detail how it has adhered to the Auditor General's directions.¹⁹⁷ The UCG submitted that YEC has failed to do so on this and several other capital projects and requested that the Board deny recovery of one-third of the cost overruns requested to be placed into rate base. UCG requested further that the Board direct that an independent audit be conducted on the LNG plant project, with all costs held in WIP until the audit is completed and publicly reviewed.¹⁹⁸

¹⁹⁴ YEC response to YUB-YEC-1-70, Table 1, PDF page 254.

¹⁹⁵ YEC response to YUB-YEC-1-70, Table 1, PDF page 254.

¹⁹⁶ UCG final argument, page 45, paragraph 293, PDF page 46.

¹⁹⁷ UCG final argument, page 46, paragraph 297, PDF page 47.

¹⁹⁸ UCG final argument, page 47, paragraph 307, PDF page 48.

403. Mr. Maissan submitted that YEC did not provide clear, objectively comparable analyses on the LNG plant and its alternatives. Mr. Maissan laid out what he believed were the assumptions necessary to favour the LNG plant over a diesel alternative, including assumptions around the relative prices of LNG and diesel, lower usage of diesel generators compared to the LNG, and a lack of new renewable energy supplies added. Mr. Maissan submitted that these assumptions all favour LNG and that different assumptions would show that the case for LNG is marginal at best. Accordingly, Mr. Maissan recommended that the Board order YEC, when proposing energy supply projects, to provide objectively comparable analyses of alternatives examined, including analyses on a range of realistically possible outcomes of any accompanying assumptions.¹⁹⁹

Views of the Board

404. The issue before the Board in this application is whether the costs of the LNG plant were prudently incurred. The Board will not revisit its recommendation for approval of the LNG project or the underlying assumptions used to make the case for the use of LNG over diesel. The UCG submissions were not of assistance to the Board in making its determination on whether the costs were prudently incurred.

405. The Board accepts that the additional costs, as described by YEC, are the result of requirements of the YESAB and YOGA permitting. Therefore, the Board is of the view that these cost overruns are not a result of insufficient cost controls, as suggested by UCG. Accordingly, the Board finds that a reduction in the costs for the LNG plant and an independent audit of this project are not necessary.

6.1.1.6 LNG third engine

406. This project will add a third 4.4 MW natural gas-fired generation unit at the Whitehorse thermal plant by early 2019. YEC forecast capital costs of \$3.04 million in 2017 and \$2.7 million in 2018 and a total of \$6.2 million for this project. However, YEC is not asking for the costs of this project to be added to rate base for the test years.

407. The 2016 Resource Plan identified the LNG third engine as one of the preferred options for addressing the dependable capacity gap in a cost-effective manner in the near term. YEC stated:

The 2016 Resource Plan identified a dependable capacity shortfall for the Yukon Integrated System under its single contingency (N-1) capacity reliability criterion that approximates 6 MW in 2017, increasing to 10-11 MW by 2019.²³ Yukon Energy is required to provide sufficient dependable winter capacity to meet the single contingency capacity reliability criterion, i.e., there is no acceptable "do nothing" option given the need to maintain reliable service, and permanent solutions (rather than relying upon temporary options such as mobile diesel) are needed to address an ongoing and growing dependable capacity shortfall.²⁰⁰

¹⁹⁹ Maissan argument, section 16, page 9, PDF page 10.

²⁰⁰ YEC application, page 5-27, PDF page 198.

408. YEC submitted that regulatory reviews for the project have been concluded and that the design, procurement and installation of the third engine will be completed mainly in 2017 and 2018, with the engine planned to be in service in the first quarter of 2019.

409. In response to a Board IR, YEC updated the project costs to \$8.9 million. YEC explained that \$1.669 million of that cost increase resulted from the omission of key cost items from the original estimate, including installation, engineering, project management and commissioning, which the owner's engineer had assumed were included in the scope of the supplier's preliminary proposal. Balance of plant costs increased by \$1.372 million due to an increase in electrical installation costs and inclusion of a "General Contractor premium management of the Balance of Plant contract that was omitted from the Stagegate 3 estimate." YEC-owner costs increased by \$0.113 million due to an increase of forecast labour and the addition of construction support costs. Lastly, the contingency increased by \$0.240 million due to development of a comprehensive risk-based contingency for the updated project cost estimate.²⁰¹

Views of the interveners

410. UCG submitted that this project was not mentioned in YEC's previous GRA and that YEC was unable to provide a business case for this project. UCG submitted further that YEC has not explained why the third LNG plant was needed in 2019 and that no evidence on the costs and benefits of alternatives was presented. Accordingly, UCG submitted that because YEC proceeded with this project without a Part 3 review and without any evidence and business case, YEC and its shareholder should be held accountable for all costs related to this project.²⁰²

411. Mr. Maissan submitted that this project amounts to a per-MW cost of approximately \$2.02 million, compared to \$3.11 million per MW for a new 20 MW diesel plant, \$5 million per MW for a new 20 MW LNG plant and \$3.425 to 5.425 million per MW for the battery storage project. Accordingly, Mr. Maissan recommended that the Board approve the third LNG engine project.²⁰³

Views of the Board

412. The Board agrees with Mr. Maissan that the cost per MW of the third LNG engine project is favourable when compared to alternative projects. Therefore, the Board finds that it is reasonable for YEC to continue with this project. The Board also accepts YEC's submission with respect to the N-1 capacity reliability criterion in support of this project.

413. Although in its reply argument YEC stated that this project might be brought into service late in 2018, it was not requesting that the costs of the project be added to rate base for the test years. As this project is not part of the rate base additions for this test period, any determination on the prudence of the costs for this project are deferred until YEC applies for this project to be put into rate base. The Board considers that the submissions of UCG on this project were not of

²⁰¹ YEC response to YUB-YEC-1-71, PDF page 257.

²⁰² UCG final argument, page 47, paragraph 313, PDF page 48.

²⁰³ Maissan argument, section 17, pages 9, 10, PDF pages 10,11.

assistance to it in making a determination on this project because the submissions were not based on the facts before the Board.

6.1.1.7 Other major projects

414. YEC also included a number of other major projects. These are described in the following paragraphs.

415. YEC stated that Hydro Unit #WH4 is a critical hydro generation asset and a 10-year major overhaul is required as part of YEC's ongoing preventative maintenance program. During the replacement process, the following additional replacement activities will also be undertaken: WH4 Rotor Spider Replacement to address stress cracks which require immediate and extensive repair; and WH4 Excitation Replacement (recommended following post-event analysis of two outages in 2014). The business case for the project, including estimated costs, is provided in Section 5.2.1.5 of the application and includes a review of project elements, justification and costs. The costs are estimated at \$4.29 million.

416. YEC explained that the last 10-year overhaul of Hydro Unit #MH2 was completed in 2002; YEC added that it was able to defer the requirement for a major overhaul beyond the 10-year period, as MH2 has not been run on a full-time basis since 2011. However, certain components are now at end of life, and a major overhaul is required in 2018 if the unit is to continue to be operated. The business case for this project, including estimated costs, is provided in the application at Section 5.2.1.6. A study regarding options for the future of the Mayo A facility was completed by KGS in 2016, and KGS determined refurbishment of the facility to be the most optimal solution. Given that continued operation of the Mayo A facility was determined to be economic, YEC submitted that the 10-year major overhaul and upgrades to MH2 are required to enable ongoing operation prior to the full Mayo refurbishment. The costs are estimated at \$1.657 million.

417. YEC stated that the T&D breaker replacements project was to replace medium- and high-voltage breakers in YEC substations as required by the equipment manufacturer. Both models of breaker are at end of life and have been phased out, making it difficult to find replacement parts. YEC added that the replacement of these assets will also result in O&M savings estimated at about \$30,000 every three to five years. The business case for this project, including estimated costs for work to be completed by the end of 2018, is provided in the application at Section 5.2.1.7. YEC explained that the project will be capitalized as the breakers are replaced and put into service. In CW-YEC-1-39, YEC reviewed the O&M end-of-life assessment and analysis conducted by YEC that demonstrates end of life; the response notes that, based on the YEC condition assessment and the consequences assessment, the risk to YEC is deemed unacceptable.

418. YEC stated that the T&D line replacement project was to replace key components for YEC transmission lines which were approaching the end of their economic life. YEC added that it commissioned an external asset assessment which indicated that a large number of cross arms and insulators are at end of life and have a high risk of failure. The business case for this project, including estimated costs for work completed to the end of 2018, is provided in the application at Section 5.2.1.8. In CW-YEC-1-40, YEC provided a copy of the external assessment undertaken as well as documents and instructions provided to the entity conducting the assessment. The

alternative to the project was to respond to structure and component failures as they occur which might lead to significant reliability impacts and higher overall costs as well as employee health and safety risks related to emergency response. The project would be carried out over five years to complete the required replacements beginning in 2018 and has a total cost of \$11.5 million, with forecast spending in the 2018 test year of \$2.0 million.

419. YEC stated that the Wareham spillway gate hoist replacement was undertaken because the hoist was determined to be at end of life through both internal review and external assessment. The business case for this project, including estimated costs and options reviewed and the basis for the preferred option, was provided in the application at Section 5.2.1.9. The project was completed in 2015 with a total cost of \$2.7 million.

420. YEC stated that the Whistle Bend supply/Takhini upgrade was identified in the 2012/13 GRA. This project was for the reinforcement of transmission line L172 between Takhini and Whitehorse and to connect the Whistle Bend Subdivision to the Yukon grid. The business case for this project, including project elements, justification and estimated costs, was provided in the application at Section 5.2.1.10. Work was completed over three years with final connection occurring in early 2015. Total project costs were approximately \$11.4 million. This amount was \$0.600 million less than the original budget amount due to the use of internal YEC staff as well as the installation of a substation bypass which enabled reduced diesel generation and greater schedule flexibility.

Views of the Board

421. The Board has reviewed each of these major capital projects and the supporting evidence on the record of this proceeding. The Board considers that each of these projects is necessary and the associated costs are prudently incurred by YEC. However, the Board notes that the Hydro unit #WH4 overhaul, T&D – breaker replacements include 2017 costs that must be updated for actuals. Accordingly, the Board directs YEC to update its 2017 costs to reflect 2017 actuals for those projects, in its compliance filing to this decision.

422. The hydro unit #MH2 overhaul, T&D – line replacement, Wareham spillway gate hoist replacement and Whistle Bend supply/Takhini upgrade do not include costs for 2017. YEC is directed to reflect the 2018 forecast costs for these projects in its compliance filing.

6.1.2 Projects between \$100,000 and \$1 million

423. YEC submitted that the growth in net rate base due to projects between \$100,000 and \$1 million reflects the ongoing need to refurbish old assets and improve grid reliability. YEC's application included approximately \$6.3 million of previously deferred overhaul costs being brought into rate base as of January 1, 2017. YEC stated that no spending on overhauls is included for the test years.

424. Excluding overhauls, total spending on PP&E from 2013 to 2016 for these projects averaged \$6.770 million, with \$4.753 million for projects added to rate base in 2017 and \$5.933 million for 2018. Generation project expenditures are forecast at \$1.065 million in 2017 and \$1.094 million in 2018. Transmission project expenditures are forecast at \$1.615 million in 2017 and

\$1.625 million in 2018. Distribution projects are forecast at \$0.500 million in 2017 and \$0.715 million in 2018. General plant and equipment projects are forecast at \$1.574 million in 2017 and \$2.499 million in 2018.

6.1.2.1 Aishihik control structure refurbishment

425. YEC forecast \$325,000 in 2018 to assess the Aishihik lake auxiliary control structure, which YEC submitted is in very poor condition, to determine if it will be repaired or replaced.

Views of the Board

426. YEC provided no information on the specific activities that will be carried out as part of this assessment. Given that YEC has already observed that the deck timbers are worn and rotting and some of the support beams are crushed and “are in danger of failing completely,”²⁰⁴ the Board is of the view that the amount of \$325,000 simply to assess the structure is excessive and, in this case, is not necessary before taking action on the repairs or replacement. The Board is of the view that the funds would be better spent carrying out the repair or replacement. Therefore, the Board denies YEC’s proposed \$325,000 for the current test period and directs YEC to reflect this finding in its compliance filing.

6.1.2.2 Faro diesel building ventilation

427. YEC forecast \$100,000 for 2018 to install new exhaust fans to improve heat and smoke removal from the Faro diesel generating plant. YEC stated that the present extractor fan is inefficient and results in overheating when the outside temperature exceeds 10 C.

Views of the Board

428. In the 2016 Resource Plan, YEC lists two diesel units at Faro, one of which is scheduled to be retired in 2021 and the second in 2040.²⁰⁵ Interveners did not provide any comments on this project. YEC did not provide any evidence on the frequency of the overheating issue and did not indicate whether the project could be deferred until 2021 when one of the diesel units is to be retired. YEC is directed to provide information in its compliance filing on the frequency of the overheating issue and whether the project could be deferred until 2021 when one of the two diesel units is to be replaced. Further, YEC is to state in its compliance filing if the 2021 unit replacement will require additional alterations to the Faro diesel building.

6.1.2.3 Wareham dam blackstart generator

429. YEC forecast \$120,000 for 2017 to install a blackstart generator allowing for full operational power to the Wareham lake dam spill gates and head gates during an outage. YEC indicated that there is currently no method for manually opening the spill gates and that the potential exists for water to overtop the dam. YEC added that in the case of an extended cold

²⁰⁴ YEC application, page 5.3-2, Appendix 5.3, PDF page 245.

²⁰⁵ 2016 Resource Plan Part 1, page 4-40, Table 4.2, PDF page 138.

temperature outage, the generator would be able to power heaters and bubblers to prevent the spill gates from freezing shut.

430. Interveners did not provide any comments on this project. Although YEC has not provided information on the frequency of previous problems encountered due to the lack of a blackstart generator at this location or with respect to the likelihood of such problems arising in the future. The Board considers the potential of the spill gates freezing shut to be a significant event and therefore accepts the costs for this project as submitted by YEC.

6.1.2.4 Whitehorse Wind 1 decommission

431. YEC stated that it spent \$16,705 from 2013 to 2016 and forecast an additional \$111,557 for 2017 to decommission the Whitehorse wind 1 turbine, which was retired from service in 2014.

Views of the Board

432. The Board accepts that these costs are reasonable and prudent. Accordingly, the Board approves this project and directs YEC to update the associated costs to include 2017 actuals in the compliance filing to this decision.

6.1.2.5 Dawson P158 T1/T2 transformer

433. YEC forecast \$200,000 for 2018 to address safety concerns with the main transformer at the Dawson Diesel plant. Specifically, the project involves expanding the ground grid, moving the overhead express feeder connection lines underground and securing the area with an appropriately sized fence.

434. During the oral hearing, YEC was asked whether, at the time the transformer was built in 2004, there were ground clearance or fencing height standards for transformers. In an undertaking to provide that information, YEC stated:

YEC does not have ready access to the standards that would have applied at the time of construction (2004). However, YEC can confirm that the design-build contract with the constructor specified that all works were to be compliant with the Canadian Electrical Code, the Alberta Electrical and Communication Utility Code (Yukon does not have its own code) and the Building Code of Canada among others.

Views of the Board

435. The Board notes that this project was included and approved in YEC's 2012-13 GRA,²⁰⁶ however, it now appears that this work was not completed by YEC, and YEC has not provided any explanation for not carrying out this project. Given that YEC has provided no evidence indicating that the transformer was improperly constructed in 2004, and given that this project was approved but not carried out in the subsequent six years since approval, the Board does not accept YEC's submission that this project is necessary to address safety concerns. As such, the prudence of the related costs has not been shown. Consequently, the Board denies the inclusion

²⁰⁶ YEC 2012 GRA, page 5.4-10, PDF page 250.

in rate base of YEC's proposed \$200,000 for this project and directs YEC to reflect this finding in its compliance filing.

6.1.2.6 Substation protection and control minor upgrades

436. YEC stated that it spent \$212,607 from 2013 to 2016 and forecast \$50,000 in 2017 and \$100,000 in 2018 for this project. YEC submitted that its substations require a number of improvements to ensure continued safe and reliable service.

Views of the Board

437. The Board accepts that it is necessary for YEC to engage in ongoing work at its substations to ensure safe and reliable service and therefore approves this project as applied for by YEC. However, the Board directs YEC to update the costs for this project to include 2017 actuals in the compliance filing to this decision.

438. However, in subsequent GRAs, when requesting approval of any such upgrades, the Board directs YEC to include a detailed description of the work that has been carried out or will be carried out at each substation and more detailed explanations of the need for the work at each substation.

6.1.2.7 Transmission system protection upgrades

439. YEC forecast \$100,000 for 2017 to install a communications-assisted tripping scheme between Takhini, Minto Landing and Faro to reduce the extent of outages and eliminate grid separation caused by faults on transmission line L178.

Views of the Board

440. The Board considers that this project is necessary for the safe and reliable operation of the electrical system and that the costs are reasonable. Therefore, the Board approves this project and directs YEC to update the associated costs to include 2017 actuals in the compliance filing to this decision.

6.1.2.8 Callison voltage regulator automation

441. YEC forecast \$115,000 for 2018 to add automation that will allow operators at SCC or Dawson to remotely control RT1 without having to be physically present at the Callison substation six kilometers away. YEC submitted that this modification would speed up Dawson's restoration to hydro power following an outage, resulting in less diesel burned.

Views of the Board

442. The Board notes that YEC has not provided information on the amount of time that would be saved during outages nor the subsequent operating cost savings resulting from eliminating the need for an operator to travel six kilometers to the substation. Therefore, the Board finds that YEC has not sufficiently demonstrated that this project is reasonable and prudent and, as such, that it would be reasonable to incur such costs. Accordingly, the Board

denies YEC's proposed inclusion in rate base of the \$115,000 associated with this project and directs YEC to reflect this finding in its compliance filing.

6.1.2.9 Building condition report response

443. YEC forecast \$299,000 in 2018 to address concerns identified by a 2016 asset assessment on YEC-owned buildings and facilities in which components were identified as either being at end of life or not in compliance with applicable "code regulations."²⁰⁷

Views of the Board

444. The Board agrees that it is reasonable for YEC to replace end-of-life components in its buildings and facilities. However, in order to approve the related costs, additional information is needed on which of the replacements are needed as a result of components being at end of life and which are being upgraded only to meet changes to codes. Accordingly, the Board directs YEC to file, as part of its compliance filing, a detailed itemized list of the work done or proposed to be done as part of this project, a description of each item, the costs for each item and the reasons why each item must be done. The reasoning for each item should include an explanation of whether it is an end-of-life replacement or if it is bringing the component up to current codes and, in the case of the latter, a reference to the relevant code and an explanation of why the component needs to be brought up to code at this time.

6.1.2.10 Stewart-Minto local SCADA

445. YEC forecast \$165,000 in 2018 for installation of a SEL-RTAC data concentrator to allow improved SCADA control of the S251, S253 and S256 substations and allow remote diagnostic capability for engineering staff.

Views of the Board

446. YEC did not provide information on whether cost reductions would be achieved by installing the data concentrator. In addition, YEC did not explain the benefits of adding remote diagnostic capability at the substations. Therefore, the Board finds that YEC has not shown the need for the installation of the data concentrator. The Board therefore finds that the related costs are not reasonable. Accordingly, the Board denies YEC's proposal to include \$165,000 in its rate base related to the Stewart-Minto local SCADA project and directs YEC to reflect this finding in its compliance filing.

6.1.2.11 Other capital projects between \$100,000 and \$1 million

447. YEC proposed a number of other capital projects between \$100,000 and \$1 million. The Board has reviewed YEC's proposals for the Aishihik generator fire protection, Aishihik tailrace road and slope, Canyon Lake control structure and dyke refurbishment to implement dam safety recommendations, Whitehorse diesel system grounding for generators, Whitehorse local HMI/historian upgrade, L170 line access, S-150 – Whitehorse main RTU upgrade, Whitehorse-Aishihik-Faro transmission upgrades, 25 kV distribution cut-out replacement, customer extensions, Aishihik emergency signage and lighting upgrade, critical spares – system

²⁰⁷ YEC application, page 5.3-9, Appendix 5.3, PDF page 252.

requirement, Dawson derrick digger, fencing upgrades – various sites, Mayo B door installation for crane inspection, Mayo transient trailer unit, vehicle purchases, voice repeater site for Little Salmon Area, voice repeater site for Mendenhall/Champagne and WRGS hazardous materials containment projects. The Board is satisfied that these projects are needed to ensure safe and reliable electrical service and that the related costs appear to be reasonable. Accordingly, the Board approves these projects but notes that many of them include forecast costs for 2017 that must be updated to reflect 2017 actuals. Therefore, the Board directs YEC to update, in its compliance filing, 2017 costs to reflect 2017 actuals for all of the projects listed above that include forecast costs for 2017.

448. The projects listed above that do not include forecast costs for 2017 are: Whitehorse diesel system grounding for generators, 25 kV distribution cut-out replacement, Aishihik emergency signage and lighting upgrade, Mayo B door installation for crane inspection, Mayo transient unit, voice repeater site for Little Salmon area, voice repeater site for Mendenhall/Champagne and WRGS hazardous materials containment. The costs for these projects are approved for inclusion in rate base as applied for.

6.1.3 Deferred costs

449. This section reviews deferred-cost projects undertaken by YEC since the 2012/2013 GRA, including feasibility studies, continued relicensing work, regulatory work and dam safety review work.

450. Deferred costs in rate base, net of contributions approximated \$11.1 million at the end of 2013 and are forecast at approximately \$2.5 million at the end of 2016. Deferred costs in rate base are forecast at approximately \$13.9 million by the end of 2017 and \$15 million by the end of 2018, reflecting mainly the transfer of approximately \$13.9 million of deferred costs to rate base at the start of 2017.

6.1.4 Deferred - major projects over \$1 million

451. YEC submitted that the growth in rate base of \$64.9 million since 2013 includes \$9.8 million from three major deferred-cost projects, while ten other major deferred projects included in the application, with forecast costs in WIP of \$35 million at the end of 2018, do not affect rate base in the test years.

452. YEC characterized two projects (Stewart Keno City transmission project and Aishihik relicensing) as spending on sustaining capital, two projects (battery project and thermal plant project) as spending to address capacity planning requirements, and five projects (demand side management [DSM], resource plan update 2016, Gladstone diversion project, Marsh Lake storage enhancement project and Mayo Lake storage enhancement project) as spending on planning to meet other potential future generation and transmission requirements.

453. The Stewart Keno City transmission line project includes \$2.807 million in costs to the end of 2016, which are completely funded by contributions.

6.1.4.1 Aishihik generating station water use licence renewal project

454. This project includes deferred costs of \$2.899 million to the end of 2018, which are to remain in WIP with projected completion in 2019.

455. YEC stated that the Aishihik generating station's facility licence was last renewed in 2002 and will expire at the end of 2019. The total budget for the project is forecast at \$3.569 million, spread over the period from 2015 to 2019. YEC stated further that it and the Champagne and Aishihik First Nations (CAFN) are working in partnership on proposed terms and conditions for the new water license and that they entered into a protocol agreement that established shared objectives, procedures and governance in January of 2016.

456. The Board finds that renewing the Aishihik water license is a necessity for continued operation of the Aishihik generating station. Costs for the project are to remain in WIP, and prudence will be assessed at the time YEC applies to include these costs into rate base.

6.1.4.2 Battery energy storage system project

457. YEC forecast costs of \$0.500 million in 2017 and \$8.356 million in 2018, to remain in WIP with a planned in-service of 2019, for a project to create a battery energy storage system near the Takhini substation. The 2016 Resource Plan identifies a battery storage system as one of the preferred options for addressing a portion of the dependable capacity gap in a cost-effective manner. Other projects proposed to address this capacity gap are the third LNG engine (discussed in Section 6.1.1.6) and a new thermal plant (discussed in Section 6.1.4.3).

458. Depending on the type of battery selected, YEC forecasts the costs for the battery storage project of between \$21.7 million and \$27.4 million for an initial 15- to 20-year life, after which battery replacement is estimated to cost between \$17.4 million and \$22.1 million.

459. In response to a Board IR, YEC indicated that it is not aware of a northern utility using an energy storage system for electric supply capacity or energy time shift.²⁰⁸

460. During the oral hearing, YEC explained that it has applied to Natural Resources Canada (NRCan) for funding to cover the entire costs of the battery storage project. According to YEC, it has passed the initial screening process and is in the next step of NRCan's selection process.

Views of the interveners

461. Mr. Maissan submitted that the cost per MW for this project ranges from \$3.425 MW to \$5.425 MW. Mr. Maissan also noted that the Trans Grid Solutions evaluation of energy storage technologies mentioned several additional benefits of a battery storage system including power quality, grid support and possible integration of other renewables. Furthermore, Mr. Maissan estimated the annual savings resulting from offsetting diesel with LNG or LNG with hydro to be

²⁰⁸ Response to YUB-YEC-1-78 (b), PDF page 282.

approximately \$244,000. Based on his analysis, Mr. Maissan recommended that the Board support YEC's proposed battery storage project even if funding from NRCan is not received.²⁰⁹

Views of the Board

462. The Board is of the view that the estimated cost of between \$21.7 million and \$27.4 million for 4 MW of battery storage does not compare favourably to the \$6.2 million cost of the 4.4 MW third LNG engine or the \$60 million cost of a 20 MW thermal plant (discussed below) on a dollar-per-MW basis.

463. Further, the Board is of the view that, at this time, the technology used for battery storage has not been tested in northern climates such as Yukon and has not been shown to provide the benefits outlined by YEC in such jurisdictions. The Board finds that, given the costs and unproven nature of the technology in a northern environment, the project is not viable. If YEC did not have funding from NRCan, it was risky to undertake the project, considering that even the initial costs in the test years are forecast at over \$9 million dollars. For these reasons, the Board finds that expenditures on such a project are not warranted. As a result, the Board denies the inclusion of costs associated with the battery energy storage project in the revenue requirement for the test years and directs YEC to reflect this finding in its compliance filing.

6.1.4.3 Thermal plant

464. YEC forecast costs of \$0.750 million in 2017 and \$3.461 million in 2018, to remain in WIP with a planned in-service of 2020, for a thermal plant project providing up to 20 MW of new diesel or natural gas generation. This project is intended to assist in addressing the current dependable capacity shortfall by 2021. Forecast spending in 2017 and 2018 is for planning, preliminary engineering, environmental permitting and the start of detailed project design.

465. The 2016 Resource Plan identified a new 20 MW greenfield diesel plant as one of the preferred options for addressing the dependable capacity gap in a cost effective manner in the near term. YEC stated:

The 2016 Resource Plan identified a dependable capacity shortfall for the Yukon Integrated System under its single contingency (N-1) capacity reliability criterion that approximates 6 MW in 2017, increasing to about 13 MW by 2020 and 23 to 24 MW by 2021.³² Yukon Energy is required to provide sufficient dependable winter capacity to meet the single contingency capacity reliability criterion, i.e. there is no acceptable "do nothing" option given the need to maintain reliable service, and permanent solutions (rather than relying upon temporary options such as mobile diesel) are needed to address an ongoing and growing dependable capacity shortfall.²¹⁰

466. As part of the 2016 Resource Plan, Stantec Consulting Ltd. examined two sites for both diesel and natural gas plants at 5 MW, 10 MW and 20 MW. For the 20 MW option at Takhini, costs were estimated at \$62.2 million for diesel and \$100 million for natural gas. Given the

²⁰⁹ Maissan argument, Section 18, pages 10,11, PDF pages 11,12.

²¹⁰ YEC application, page 5-37, section 5.3.1.4, PDF page 208.

expected low levels of thermal generation, the present value of fuel savings with natural gas were not sufficient to offset the capital cost savings for diesel.

467. The budget for a 20 MW diesel plant for in-service by 2021 includes:

- a. \$0.75 million for completion of environmental and socio-economic baseline studies, stakeholder engagement and consultation, preliminary engineering and grid impact study in 2017;
- b. \$3.46 million for a Stagegate 3 project review followed by a YESAB proposal submission, start of detailed design and procurement of long lead equipment in 2018;
- c. \$38 million for permitting, procurement and start of construction in 2019; and
- d. \$20.1 million for construction and commissioning in 2020.

468. The 2017 work plan for the thermal project will also include a final review of all new fossil fuel generation options, including options not considered in the 2016 Resource Plan portfolio analysis, in order to confirm a final project that provides the needed capacity as soon as possible and at minimum costs.

469. Mr. Maissan submitted that it is appropriate to seriously consider the option of removing the retired Mirrlees generators and refurbishing the existing diesel plant with dual fuel engines. According to Mr. Maissan, this approach would eliminate the risks associated with permitting a new plant site and provide the advantage of using the existing diesel and LNG storage facilities. Accordingly, Mr. Maissan requested that the Board order YEC to provide a detailed comparison, including pros, cons, capital costs, operating costs and timeline to in-service for existing diesel plant refurbishment(s) and the two greenfield options (diesel and natural gas).²¹¹

Views of the Board

470. The Board is of the view that YEC has supported its case that adding capacity is needed to meet system reliability needs under the N-1 criterion and that a greenfield thermal generation plant is one of the preferred methods to add the needed capacity. However, YEC has not provided a business case in support of this project. YEC did not detail the costs and benefits associated with this project. The Board finds that it is not reasonable for YEC to proceed with the project without a detailed business case that considers the alternatives to the project. The Board notes that YEC forecast costs for 2019 and 2020 of \$38 million and \$20 million respectively. The magnitude of these costs alone is reason for proceeding cautiously. The Board is not persuaded that this project is the only way to address the predicted capacity shortfall and that the forecast costs are reasonable. The Board requires a detailed evaluation of alternatives to this project included in the business case.

²¹¹ Maissan argument, section 19, PDF page 13.

471. Given the above, the Board accepts Mr. Maissan's recommendation that YEC provide a detailed comparison of alternatives for this project, including the pros, cons, capital costs, operating costs and timeline to in-service and justification for its preferred option. Accordingly, before undertaking any further costs on this project, the Board directs YEC to provide this information in any future application for this project. Any costs incurred to date for this project are to be held in WIP until such time as a new application is brought before the Board and the Board makes a determination on that application and the prudence of the costs incurred.

6.1.4.4 Demand side management

472. YEC spent \$2.484 million up to the end of 2016 and forecast \$0.210 million in 2017 and \$0.625 million in 2018 for various demand side management (DSM) projects. YEC's DSM includes the inCharge Program (\$1.291 million to the end of 2016, \$0.190 million in 2017 and \$0.290 million in 2018), new program development (\$0.190 million in 2018), industrial DSM (\$0.082 million to the end of 2016), pilot DSM projects (\$0.051 to the end of 2016 and \$0.020 million in 2018), LED streetlight retrofits (\$0.142 million for piloting to the end of 2016, \$0.168 million in 2016 for Dawson and Mayo and \$0.080 million in 2018), internal energy conservation (\$0.353 million to the end of 2016 and \$0.025 million in 2018) and administration (\$0.397 million to the end of 2016, \$0.020 million in 2017 and \$0.020 million in 2018).

473. In response to a Board IR, YEC listed a number of DSM incentives provided by the Yukon Government.²¹²

474. YEC submitted that its DSM programs were evaluated by a third-party evaluation advisor and that they met or exceeded key performance indicators. YEC added that the 2016 Resource Plan recommends additional DSM as a cost effective way to meet energy and capacity demand.²¹³

Views of the interveners

475. The UCG submitted that there is no evidence demonstrating that any of YEC's DSM activities have been approved by the Board. The UCG added that the only approval YEC provided for DSM is Board Order 2014-06 which approved a budget of \$438,000 for DSM in 2014 and 2015. The UCG also submitted that YEC has provided no cost-benefit studies for its DSM programs that could be used to conduct a prudence analysis.²¹⁴

476. Mr. Maissan recommended that the Board approve the recovery of past DSM expenditures as requested by YEC and that the Board order YEC to proceed with capacity-focused DSM program design and implementation.²¹⁵

Views of the Board

²¹² YEC response to YUB-YEC-1-80, PDF page 292.

²¹³ YEC final argument, page 44, section 3.2.3, PDF page 46.

²¹⁴ UCG final argument, pages 69, 70, paragraphs 483- 490, PDF pages 70, 71.

²¹⁵ Maissan argument, page 13, section 20, PDF page 14.

477. In Board Order 2013-01, Appendix A: Reasons for Decision, the Board found that it was premature to approve or disallow DSM expenses until YEC and YECL jointly filed a DSM plan. Until that time, the Board directed YEC to hold all DSM-related costs in WIP.²¹⁶ YEC and YECL later submitted a five-year DSM plan, which the Board addressed in Order 2014-06. In that Order, the Board approved three DSM projects proposed by YEC and YECL: LED lighting, automotive heater timing rebates and low-cost energy efficient products. The Board also stated that it was not approving the DSM program for the five-year term and that YEC was to make a formal application to the Board before expanding the DSM program elements beyond that approved or beyond 2015.²¹⁷

478. Despite the Board determination that DSM projects were only approved up to 2015, YEC has continued with program expenditures beyond that point and has forecast continued DSM expenses during the test period. YEC did not make an application to the Board before expanding DSM programs beyond 2015. Accordingly, the Board finds that any DSM program expenditures that occurred after 2015 were not prudently incurred and are disallowed for inclusion in YEC's rate base.

479. YEC also incurred expenses on DSM projects that do not fall within the three projects approved by the Board in Order 2014-06, despite the Board's explicit statement that YEC must apply to the Board before expanding its DSM program beyond the elements approved in that order. Accordingly, the Board finds that YEC's DSM expenditures on programs not approved in Order 2014-06 (LED lighting, automotive heater timing rebates and low-cost energy efficient products) were not prudently incurred and are disallowed for inclusion in YEC's rate base.

480. Specific to LED streetlight retrofits, in Board Order 2017-01 the Board stated the following:

293. With respect to LED streetlight installations that are not end-of-life conversions, the Board directs AEY to treat the costs related to new installations or requested conversions as capital costs that attract a full customer contribution in aid of construction.²¹⁸

481. Although the Board made the above-noted finding in relation to AEY, YEC should have taken note of this finding, because such a finding equally applies to YEC. As a result, the Board considers that retrofitting streetlights at end of life with LED lights were prudent expenditures. Any LED installations that are not end-of-life conversions must not be included in YEC's rate base.

482. The Board is not persuaded that YEC should continue to operate DSM projects. YEC has indicated the benefits of expanding the program and submitted that its programs have met or exceeded key performance indicators. However, the Board notes that the Yukon government has DSM incentive programs in place, and the Board is of the view that it is better to leave DSM projects to government, rather than having ratepayers fund these projects. For these reasons, the Board is of the view that continuation of DSM programs by YEC is not necessary. Accordingly,

²¹⁶ Order 2013-01, Appendix A: Reasons for Decision, paragraph 367.

²¹⁷ Order 2014-06, Appendix A: Reasons for Decision, page 101, PDF page 106.

²¹⁸ Order 2017-01, Appendix A: Reasons for Decision, page 57, paragraph 293, page 58.

the Board denies YEC's requests to continue with any DSM programs other than end-of-life streetlight conversions as discussed above.

483. The Board directs YEC to reflect the Board's findings with respect to DSM programs, as detailed above, in its compliance filing.

6.1.4.5 Resource plan update

484. YEC completed a 20-year Resource Plan in late 2005, and the Board recommended that YEC update the plan within five years. The Resource Plan was updated in 2011 and 2016. YEC indicated that it had spent \$1.854 million up to the end of 2016 and forecast an additional \$0.150 million in 2017 for a total of \$2.004 million, which YEC proposed to amortize over five years, starting in 2017.

Views of the interveners

485. The UCG submitted that there are too many unanswered questions and not enough detail to allow the costs for the resource plan update to be recovered in the manner proposed by YEC.²¹⁹

486. The City of Whitehorse submitted that a resource plan that does not consider the possibility of disruptive technologies over a 20-year period provides an uncertain context from which capital expenditures are to be justified. Due to the omission of disruptive technologies, the City of Whitehorse submitted that the costs of the study should be excluded from rates and requested that the Board direct YEC to provide consideration of disruptive technologies in its forecast load requirements in all future rate and resource plan applications.²²⁰

487. YEC countered that longer term risks related to disruptive technology are not sufficiently defined at this time to merit changes to any of YEC's capital plans for the test years or the coming five-year period. Accordingly, YEC submitted that there is no basis for the Board to dismiss the 2016 Resource Plan or to disallow any associated costs.²²¹

Views of the Board

488. The Board agrees with YEC that any longer term risks posed by disruptive technology are not sufficiently defined to merit the exclusion of the costs for the 2016 Resource Plan from YEC's rate base. The Board finds that the evidence and submissions of CW were not of assistance to the Board on this issue.

489. The Board acknowledges that when the first resource plan was approved, the Board asked YEC to update it in five years. However, the Board also notes that the same was not requested when YEC updated the resource plan in 2016. The Board accepts that the 2016 update of the resource plan provided benefits in the form of long-term planning, risk assessment and stakeholder engagement. The Board therefore accepts that YEC's costs for the 2016 update were

²¹⁹ UCG final argument, page 69, paragraph 482, page 70.

²²⁰ Argument of the City of Whitehorse, page 6, paragraph 22, PDF page 7.

²²¹ YEC reply argument, page 33, PDF page 36.

prudently incurred and approves YEC's proposal to amortize those costs over five years. However, the forecast costs must be updated to reflect 2017 actual costs, and the Board directs YEC to do so in its compliance filing to this decision.

490. However, the Board is of the view that it is not prudent for YEC to continue with these significant expenses to update the resource plan every five years. Accordingly, the Board directs YEC to seek Board approval prior to any future updates of its resource plan. Any such application must be accompanied by a detailed proposal for both costs and scope of work, including a description of work to be carried out internally and by consultants. YEC must also include an explanation of why any work to be done by consultants cannot be carried out by internal staff.

6.1.4.6 Gladstone diversion

491. YEC spent \$4.429 million to the end of 2015 and \$0.092 million in 2016 for a total cost of \$4.521 million, to be amortized at the end of 2017 for the Gladstone diversion project.

492. YEC included this project in its 2012-2013 GRA, and the Board, in Order 2013-01, found that the project had the potential to be viable and directed that all costs be held in WIP until the project is completed or otherwise ended. At that time the project was in a prefeasibility stage. However, since that time both Champagne and Aishihik First Nations (CAFN) and the Kluane First Nation (KFN) indicated that they will not support the project. As directed by the Board in Order 2013-01, YEC has subsequently ceased work on the project and now proposes to amortize the project costs over 10 years, starting in 2017.

493. YEC noted that CAFN originally expressed opposition to the project in 2010 and 2011 and that Kluane confirmed their opposition in September 2014.

Views of the Board

494. The Board acknowledges that in Order 2013-01, it found the project to be potentially viable and directed YEC to hold its expenditures in WIP until the project was complete or otherwise ended. Given that the Board reviewed the Gladstone diversion project at that time and the project has since ended, it is reasonable to consider the approval of the costs to be added to rate base. Now the Board has to determine the prudence of the costs incurred.

495. The Board is of the view that conducting stakeholder engagement to obtain support for a project is an iterative and lengthy process. It is not therefore necessarily unreasonable or imprudent for a utility to pursue or continue to pursue a project in the face of resistance or opposition from stakeholders.

496. In this proceeding, the evidence established that by September 2014, the CAFN and KFN conclusively opposed the project and that, according to the YEC, their support was necessary for the project to proceed. No evidence was led to explain or justify why any expenditures on this project continued past September 2014. Therefore, it is the Board's view that the project was no longer viable as of September 2014. At that point, project expenditures should have stopped. For

these reasons, the Board finds that any costs incurred after September 2014 were not prudently incurred and are not recoverable from ratepayers.

497. Accordingly, the Board directs YEC to include in its compliance filing a detailed breakdown of any costs incurred after September 2014 for the Gladstone diversion project and to reflect the removal of those costs from the amount that YEC proposes to amortize for the Gladstone diversion project.

6.1.4.7 Marsh Lake Storage

498. YEC spent \$6.517 million to the end of 2015, \$0.365 million in 2016 and forecast costs of \$0.250 million in 2017 and \$1.025 million in 2018, to remain in WIP with a potential in-service date in 2022.

499. The Marsh Lake project (renamed the Southern Lakes Enhanced Storage Project) includes activities to enhance winter energy at the Whitehorse Rapids generating station. In the 2012-2013 GRA, this project had a forecast capital cost of \$10.5 million, with an earliest in-service in 2014, and was assumed to provide 1 MW of added peak winter capacity. At that time, YEC did not expect significant physical or environmental effects arising from the project but expected complex planning and permitting processes due to notable public concerns.

500. In Order 2013-01, the Board found that the Marsh Lake storage project was a viable project at the time and directed that related project costs were to be held in WIP until the project was completed.

501. Since the 2012-2013 GRA, YEC has continued to work on technical studies and assessments, stakeholder engagement and consultation, and meetings with directly affected property owners. YEC stated that the next major milestone is obtaining First Nations' support in order to progress to the YESAB assessment stage. YEC submitted that without First Nations' support, the project will be cancelled as there would be no reasonable possibility of successfully implementing the project. At the time of filing its application, YEC expected that a decision to proceed to the YESAB assessment phase would be made at a Stagegate 3 project review planned for the fourth quarter of 2017.

502. In response to a Board IR, YEC provided updated actual costs for the Marsh Lake project. YEC indicated that it had spent almost \$6.8 million to date and was forecasting an additional \$8,577,830, for a total cost almost 50 per cent higher than the 2012-2013 GRA forecast.²²²

503. During the oral hearing, YEC submitted that the Carcross/Tagish First Nation is a decision body in the YESAB process, making their support a critical component of YEC's evaluation of project risks.²²³ YEC also stated during the oral hearing that they received conditional support from the Carcross/Tagish First Nation to proceed to YESAB but that any

²²² Response to YUB-YEC-1-84, PDF page 313.

²²³ Transcript Volume 3, June 28, 2018, page 502, lines 5-13, PDF page 71.

benefits agreement has not been completed²²⁴ and that YEC also needs to bring the project back to its board to reassess public, First Nation and government support for the project.

Views of the interveners

504. The UCG submitted that it is highly unlikely that this project will move forward due to the homes and businesses on a flood plain on the Marsh/Tagish system and that it is “past the time to cut this project loose.” The UCG added that YEC must take on responsibility for the poor planning of this project and pay at least half the costs that are determined to be prudent and qualify for recovery from ratepayers.²²⁵

505. Mr. Maissan recommended that the Board support the proposed ongoing work on the Marsh Lake storage project.²²⁶

Views of the Board

506. YEC stated that it will not proceed without obtaining support from First Nations for this project. A significant amount of time has elapsed on this project, and YEC has spent almost \$7 million up to the end of 2016, with another \$1.275 million forecast to be spent in 2016 and 2017. Despite this time and effort, YEC has not been able to obtain the firm support of First Nations or the local community and is planning to take this project back to its own board for a reassessment. Furthermore, the Stagegate 3 project review, including a decision to proceed to the YESAB assessment phase which YEC stated was planned for the fourth quarter of 2017,²²⁷ had not yet happened at the time of the oral hearing in late June 2018.²²⁸

507. The costs to date for this project represent an increase of almost 50 per cent, with the project not yet nearing completion. While the Board is of the view that this project may still be viable, the Board is concerned with the amount of time and expenditures to date with little apparent progress. The Board reminds YEC that if it chooses to continue developing this project, the onus will be on YEC to demonstrate the prudence of all expenditures related to the project.

6.1.4.8 Mayo Lake Storage

508. For the Mayo Lake storage project, YEC has spent \$2.121 million to the end of 2015 and \$0.285 million in 2016, and forecasts \$0.100 million in 2017 and \$0.850 million in 2018, to remain in WIP with a potential in-service of 2022.

509. This project was reviewed during the 2012-2013 GRA as a major deferred project requiring a licence amendment without any physical works. In Order 2013-01, the Board approved the project, noting that it would increase renewable power generation capability

²²⁴ Transcript Volume 3, June 28, 2018, page 505, lines 19-23, PDF page 74.

²²⁵ UCG final argument, page 76, PDF page 77.

²²⁶ Maissan argument, section 21, page 13, PDF page 14.

²²⁷ YEC application, page 5-47, PDF page 218.

²²⁸ Transcript Volume 3, June 28, 2018, page 506, line 16, PDF page 75.

without requiring any physical works and would be amortized over the term of the Mayo generation facility water use licence.

510. A subsequent study by external engineers showed that sediment in the Mayo Lake outlet channel is constraining water flow through the channel at the low end of the licensed storage range, preventing realization of any benefits from the Mayo Lake Storage project. YEC determined that removal of sediment deposits is required in order to utilize the additional storage and that a separate design, assessment and regulatory review process was required to do so.

511. The project was submitted to the YESAA Designated Office in August 2015, which suggested that the project be reviewed with an unrelated project proposed for the lower Mayo River. YEC withdrew the Mayo Lake storage project to allow the other project to move forward in a timely manner, on the understanding that it would be resubmitted at a later date.

512. Mr. Maissan recommended that the Board support the proposed ongoing work on the Mayo Lake storage project.²²⁹

Views of the Board

513. The Board approved the Mayo Lake storage enhancement in Order 2013-01. Given that sediment removal is necessary to realize any benefits from this project, the Board considers that it is prudent to expand the scope of work for this project accordingly. Therefore, the Board approves the Mayo Lake storage enhancement project as applied for. The costs for this project are to remain in WIP, and the prudence of the costs will be assessed at the time the project is complete and YEC applies to add the costs to rate base.

6.1.5 Deferred - Projects Between \$100,000 and \$1 million

514. YEC forecast total spending on deferred-cost capital projects between \$100,000 and \$1 million at \$2.2 million in 2017 and \$2.9 million in 2018. The total increase in rate base from deferred projects between \$100,000 and \$1 million, including transfers from WIP spending prior to 2017, is \$4.9 million in 2017 and \$3.3 million in 2018.

Table 24. Deferred – projects between \$100,000 and \$1 million (\$ million)

Project	Year-end 2016	2017	2018	Totals
Feasibility	\$0.712	\$0.888	\$2.250	\$1.984
Hearing reserve account	\$0.105	\$0.713	\$0	\$0.818
Relicensing	\$0	\$0.25	\$0.25	\$0.5
Regulatory and dam safety review	\$0	\$0	\$0	\$0
Totals	\$0.817	\$1.851	\$2.500	\$3.302

²²⁹ Maissan argument, section 21, PDF page 14.

6.1.5.1 Mayo and Aishihik Climate Change Study

515. For the Mayo and Aishihik climate change study, YEC spent \$121,530 prior to 2017 and forecast \$160,000 for each of 2017 and 2018. This project will deliver research and modelling to better understand how climate change will impact the Aishihik and Mayo drainages to help inform inputs to YEC's generation model.

Views of the Board

516. In response to a UCG IR, YEC indicated that the 35 years of data inflows into YECSIM reflect what was recorded over the 35 years, including any climate change impacts relevant to those years.²³⁰ Given YEC's statement that its YECSIM model includes climate change impacts, the Board finds that YEC has not adequately demonstrated that it is necessary to engage in a separate study specifically on climate change impacts. Accordingly, the Board finds there is no justification for this project and directs YEC to remove these costs from its revenue requirement for each of 2017 and 2018 and not recover the 2016 costs. The Board directs YEC further to reflect this finding in its compliance filing.

6.1.5.2 Time-of-use rate structure and smart grid

517. YEC forecast costs of \$100,000 in 2017 to assess the potential for a time-of-use rate structure and associated smart grid.

518. In paragraphs 453 to 456 of Board Order 2017-01, the Board stated that it is of the view that studies related to smart grid are best conducted by industry or funded by government initiatives and directed AEY to remove forecast expenditures and cost recovery related to its proposals.

519. The Board finds that YEC has not provided information that persuades the Board that a study on smart grid and time-of-use rates is useful or needed. Accordingly, the Board directs YEC to remove any forecast expenditures and cost recovery related to this project in its compliance filing to this decision.

6.1.5.3 Mt Sumanik Wind Feasibility Study

520. For the Mt Sumanik wind feasibility study, YEC spent \$540,280 prior to 2017 and forecast \$50,000 in 2017 and \$250,000 in 2018. This project will collect data that will allow YEC to confirm the validity of potential wind generation options.

521. YEC has not stated the endpoint of this project or what the potential benefits will be. The Board is not prepared to accept these costs until YEC provides a business case and a full justification of these costs.

²³⁰ Consolidated round 2 IR responses, UCG-YEC-2-8, PDF page 97.

6.1.5.4 Northern Diesel Plant Location Study

522. YEC has forecast \$100,000 for 2018 to assess the options of moving the Dawson and Mayo diesel plants from their present locations due to concerns over flood risk and plant noise, and stated that such moves would bring the generators closer to substations. YEC stated that the study will determine the costs, impacts and options and then make a recommendation of relocating each diesel plant.

523. In an IR, the Board asked YEC if it has investigated any alternatives to relocation to mitigate the flood and plant noise issues. YEC's response was:

The test year spending does not include physically moving the plants, only studying the various options. The study will investigate alternatives to moving the plants, other mitigation options to address noise and flood risk, and potential uses for the space if the plant(s) are moved.²³¹

524. During the oral hearing, YEC explained that there are “a couple of drivers” for this project, including complaints from the community that the Dawson plant is located in downtown Dawson, the age and condition of the physical infrastructure, and the location of generating assets. YEC added that it is at a “juncture” and needs to look at a long-term strategy for where the two diesel units might be located. Lastly, YEC stated that at this time it does not see any immediate need for investment and that this study is looking at the future long-term location.²³²

Views of the Board

525. Given that YEC has indicated that it will not be taking any action to move the two plants in the near future, the Board considers that YEC has not sufficiently demonstrated the need for the study at this time and that the associated costs are reasonable. Accordingly, the Board directs YEC to remove any forecast expenditures and cost recovery related to the northern diesel plant location study.

6.1.5.5 Whitehorse hydro uprate

526. YEC is forecasting \$450,000 in 2018 to select an alternative to uprate the Whitehorse hydro units. This project will select an owner's engineer and create a scope of work and is expected to be complete by 2020. In response to a Board IR, YEC stated that it has never completed a hydro uprate project.²³³

527. The Board considers YEC has not adequately quantified the expected benefits and costs of uprating the Whitehorse hydro units in order to justify an expense of this magnitude for an investigation. Accordingly, the Board denies YEC's proposed Whitehorse hydro uprate project and directs YEC to remove any forecast expenditures and cost recovery related to this project in its compliance filing.

²³¹ YEC response to YUB-YEC-1-86 (d), PDF page 322.

²³² Transcript Volume 3, June 28, 2018, pages 444-446, lines 24-3, PDF pages 13-15.

²³³ YEC response to YUB-YEC-1-86 (e), PDF page 322.

6.1.5.6 Small hydro

528. YEC forecast \$625,000 in 2018 for a prefeasibility stage assessment to confirm site selection and project need.

529. The Board finds that YEC has not adequately quantified the benefits and costs of a small hydro project in order to justify an expense of this magnitude on the prefeasibility stage assessment. The Board is of the view that small hydro is better left to other entities such as independent power producers. Accordingly, the Board denies YEC's proposed small hydro project and directs YEC to remove any forecast expenditures and cost recoveries related to this project in its compliance filing.

6.1.5.7 Other deferred projects between \$100,000 and \$1 million

530. YEC also proposed a number of other deferred projects between \$100,000 and \$1 million. The Board has reviewed the detailed line inspection, development of asset management program, forecasting model integration, asset appraisal, general rate application - 2017-2018 and Aishihik remediation work projects and finds that these projects are reasonable and the associated costs prudent. Accordingly, the Board approves these deferred projects as filed.

6.2 Policies

6.2.1 Planning cost accounting policy (PCAP)

531. In its application,²³⁴ YEC explained that in Order 2013-01, the Board rejected the planning cost accounting policy (PCAP) that had been filed in its 2012-2013 GRA. In the current application, YEC submitted an updated PCAP²³⁵ intended to reflect the Board's directions from Order 2013-01.

532. Specifically, in Order 2013-01, the Board determined that the proposed policy would not have allowed the Board and interveners sufficient opportunity to test the prudence of all expenditures incurred by YEC with respect to deferred costs.²³⁶

533. In order to address these concerns, YEC submitted a revised PCAP which took into consideration the comments of the Board. Wording within the policy was changed or added to provide greater clarity to support YEC's assertion that it was "not seeking to, and has never intended to, include in rates any deferred or other costs that had not been subject to review and approval by the Board."²³⁷

534. In response to an IR,²³⁸ YEC outlined key changes made to the new PCAP as follows:

- a. Removal of a reference to "reasonable assurance test" in Section 2.3.

²³⁴ YEC application, page 1-10, PDF page 26.

²³⁵ YEC application, Appendix 5.1, PDF pages 237-239.

²³⁶ Board Order 2013-01, Appendix A: Reasons for Decision, March 25, 2013, page 83, paragraph 405, PDF page 84.

²³⁷ YEC final argument, page 49, section 3.2.4, PDF page 51.

²³⁸ YEC response to YUB-YEC-1-75, PDF pages 268, 269.

- b. Addition of Section 4 to confirm that while YEC will close out and begin amortization of studies as prescribed by the PCAP, all deferred costs will be subject to a prudence review by the YUB prior to any change in customer rates.
- c. Insertion of a new Section 2.3 to address how viability of planning cost projects will be assessed on an ongoing basis.
- d. Addition of new Section 2.5 wording to clarify how planning costs will be amortized in the event a project does not proceed. The specific provisions state that: accumulated planning and studies costs which are less than \$1 million will be amortized over a period of five years; whereas accumulated planning and studies costs which have exceeded \$1 million will be amortized over a period of 10 years.

535. In its argument, UCG made various statements implying that the proposed policy should be rejected but did not express or identify concerns with specific sections or language within the proposed PCAP. The UCG questioned in general the capitalization of transfers of (deferred) project costs between WIP and rate base and whether cancelled projects are, in fact, a cost to YEC of “rendering the public utility service for the test period.” The UCG argued that the deferred costs of cancelled projects should not be added to rate base as they do not render any public service. The UCG also stated it was imperative for YEC to provide evidence from other jurisdictions with respect to the treatment of planning study costs, and without such information, the Board is not able to fulfill its mandate to establish process and policy based on a consideration of the policies across Canada.²³⁹

536. YEC countered that UCG’s comments on the proposed PCAP provide no assistance to the Board and that UCG has had ample opportunity to review and seek clarifications on the proposed policy. YEC further stated that it continues to follow the historical practice of closing out projects from WIP when a project is completed or otherwise cancelled and there is “no impact on rates until and unless YEC applies for and is granted leave to include these costs in rates by the YUB.”²⁴⁰

537. The UCG in reply argument continued to assert there is insufficient evidence on the impact of the proposed policy and that it is impossible for the Board to approve changes to a policy without knowing the impact those changes will have on ratepayers, particularly if practices in other Canadian jurisdictions is unknown.²⁴¹

538. No other party raised any issues with respect to YEC’s proposed PCAP.

Views of the Board

539. The Board does not agree with UCG that it is necessary to canvas other Canadian utilities for the purpose of establishing a PCAP relevant to the operations of YEC. While it may be beneficial in specific circumstances to solicit information from other utilities in other jurisdictions on a specific business practice, ultimately, the YUB is able to assess and determine issues related to its rate-setting responsibilities under the *Public Utilities Act*. In the case of YEC,

²³⁹ UCG final argument, pages 48, 49, paragraphs 314-321, PDF pages 49, 50.

²⁴⁰ YEC reply argument, page 38, PDF page 41.

²⁴¹ UCG reply argument, pages 20, 21, paragraph 88, PDF pages 21, 22.

the Board sees no significant gains to be achieved in following the suggestion of UCG with respect to the PCAP when the purpose of the revisions conducted by the YEC was to address specific shortcomings elucidated by the YUB in Board Order 2013-01 in its earlier draft policy.

540. The Board finds that the proposed PCAP, as submitted in its revised form in the current application, has addressed the specific concerns raised by the Board in Order 2013-01. The Board approves the PCAP submitted by YEC in its application as Appendix 5-1.

6.2.2 New Vegetation Management Policy

541. In Board Order 2013-01, YEC was directed to provide a completed transmission Vegetation Management policy for review in its next GRA. Specifically, the Board stated:

108. However, for the period beyond the test years (future years), the Board directs YEC to create a transmission vegetation management deferral account. In future years, distribution and transmission vegetation management-related costs greater than 2011 actual brushing costs are to be held in the newly created vegetation management deferral account.

109. The Board further directs in its next GRA to provide its transmission vegetation management policy. At that time, the Board and interveners will have the opportunity to test the reasonableness of the proposed policy and the costs held in the vegetation management deferral account.

...

118. The Board further directs that, in its next GRA, YEC is to provide its distribution and transmission vegetation management plan. At that time the Board and interveners will have the opportunity to test reasonableness of the proposed policy and the costs held in the vegetation management deferral account.²⁴²

542. In the current application, YEC submitted its integrated Vegetation Management policy to address the Board's directions from Order 2013-01.²⁴³

543. In response to an IR, YEC stated that beyond the application of a registered herbicide requiring certain permits, there were certain conditions under which YEC would consider an herbicide application program:

- a. The program is considered to be safe by regulators;
- b. The program achieves the required vegetation management to safely maintain transmission line right of ways;
- c. The herbicide program is cost effective in comparison to traditional mechanical methods or as a combination of traditional mechanical methods and herbicide program; and
- d. The program has stakeholder acceptance.

²⁴² Board Order 2013-01, Appendix A: Reasons for Decision, March 25, 2013, pages 24-26, paragraphs 108, 109 and 118, PDF pages 25, -27.

²⁴³ YEC application, page 1-10, PDF page 26 and Appendix 3.1, PDF pages 75-79.

544. Despite past studies demonstrating that herbicide application could be very effective and cost-efficient, if stakeholder acceptance is not achievable, YEC stated it would continue with traditional mechanical methods of vegetation management.²⁴⁴

545. In response to an IR from UCG,²⁴⁵ YEC explained its goal of achieving 10 or fewer controllable outages annually, which includes vegetation-caused outages, and its goal to sustain this level of reliability on an ongoing basis. Further, YEC provided a chart illustrating the effects of its vegetation management policy on reliability statistics, which is reproduced in the following table:

Table 25. Tree-caused outages

Year	Outages
2012	24
2013	22
2014	7
2015	8
2016	3

Source: UCG-YEC-1-38, PDF page 174.

546. CW filed evidence stating its concern that, in addition to the Vegetation Management policy being YEC’s “first version”, the policy had been developed with minimal input from other utilities. CW recommended that “YEC be directed to compare its vegetation management policy to that of other utilities and provide a report in the compliance filing... [and]... if it proves that YEC’s vegetation management policy drives costs that are higher than required the budget for vegetation management should be reduced.”²⁴⁶

547. In its evidence, CW implied it had significant experience with the review of Vegetation Management policies over the last 15 years, but during the hearing, CW could not identify specific areas of concern or a specific section within the policy that required revision.

548. CW was questioned on how the Board could determine in a compliance filing a causal link between costs and vegetation policies in other jurisdictions. The Board also questioned the implementation of the CW recommendations (on what appeared to be a retrospective basis) given the timing of the hearing and potential for a compliance filing. CW responded that the causal link would be the type of vegetation management done and that, given the utility would be providing 2017 actuals, it may “be late to ask for forecast cuts,” but it would still be useful to understand how YEC’s vegetation policy lines up with others that are in a similar area.²⁴⁷

549. YEC countered that CW’s evidence ignored relevant history on YEC’s due diligence with respect to the development of its vegetation management policy. YEC provided details of the

²⁴⁴ YEC response to YUB-YEC-1-19, PDF pages 57, 58; JM-YEC-1-14, PDF pages 63, 102, 104.

²⁴⁵ YEC response to UCG-YEC-1-38, PDF pages 173, 174.

²⁴⁶ CW evidence, page 10, Q&A 17, PDF page 11.

²⁴⁷ Transcript Volume 3, June 28, 2018, pages 668, 669, lines 12-16, PDF pages 237, 238.

development of its policy beginning with Board Order 2008-09 which directed YEC to develop a comprehensive brushing policy, which YEC undertook by way of an independent study conducted in 2010. During the time of YEC's 2012-2013 GRA, field testing of the recommendations arising from the study were being completed, with the development of the policy anticipated in 2013. In Order 2013-01, the Board recognized the work completed thus far by YEC with respect to industry best practices and directed YEC to provide its transmission Vegetation Management policy in its next GRA, anticipating that the Board and interveners would have the opportunity to test the reasonableness of the proposed policy.²⁴⁸

550. Mr. Maissan agreed that YEC has studied the vegetation management issue for some time and has now established a regular brushing program that does not include the use of herbicides. The result has been reflected in reduced outages and the lowering of the cost of brushing. Mr. Maissan recommended that the Board approve YEC's Vegetation Management policy.²⁴⁹

551. In argument, CW stated its recommendation that "the Board direct YEC in its future GRA to provide a comparison of its vegetation management policy with utilities of similar size or facing similar geographical issues," such as those in northern British Columbia or Alberta. CW also requested that the vegetation management plan not include the use of herbicides within the City of Whitehorse boundaries.²⁵⁰

552. YEC argued that the Board and interveners have had the opportunity to review the Vegetation Management policy and associated costs as part of the current application which are consistent with the policy and studies previously reviewed by the Board. YEC stated it fully complied with previous Board directives related to brushing and vegetation management and the associated policy is prudent and was informed by a review of industry best practices and YEC's own operating experience.²⁵¹

553. CW acknowledged that, in YEC's rebuttal, YEC clarified that it had conducted a multi-utility survey of best practices through CEATI International Inc. in 2012 and that this survey of best practices informed the development of the brushing policy. CW argued that the best practices information was six years out of date and recommended that YEC be "directed to update its analysis of vegetation management best practices of North America utilities on a more frequent basis going forward and to make the results of those studies publicly available."²⁵²

554. The UCG expressed similar concern with YEC's Vegetation Management policy. It argued that it was not sufficient to rely on a six-year-old study given the evolving needs of utilities in the area of vegetation management.²⁵³ Expanding on this in reply argument, UCG stated that while comparisons of vegetation policies with other jurisdictions could be instructive, it was the actual results and costs of operating under such policies that could determine best practices in Yukon. The UCG stated that any flaws in the proposed Vegetation Management

²⁴⁸ YEC rebuttal, page 6, PDF page 8, and Board Order 2013-01 Appendix A: Reasons for Decision, March 25, 2013, pages 24, 25, paragraph 109, PDF pages 26, 27.

²⁴⁹ Mr. Maissan final argument, page 4, PDF page 5.

²⁵⁰ CW final argument, paragraphs 45, 46, pages 12, 13, PDF pages 13, 14.

²⁵¹ YEC final argument, page 25, PDF page 27.

²⁵² CW reply argument, page 8, paragraph 32, PDF page 9.

²⁵³ UCG final argument, page 26, paragraph 180, PDF page 27.

policy must be addressed before the policy is approved rather than directing a follow-up as suggested by CW. The UCG added that “repercussions” were missing from YEC’s proposed Vegetation Management policy, addressing if the policy was not followed, or if YEC was not effective in achieving its outages goals which should have metrics assigned and upon which the policy’s effectiveness would be measured.²⁵⁴

555. YEC summarized that “[o]verall, the process that resulted in the current Vegetation Management policy displayed ample and appropriate due diligence, including adequate research into other utility policies and practices with involvement of jointly funded external expertise, and there is no need for further reporting or review to compare YEC’s Vegetation Management policy to other utilities.”²⁵⁵

556. YEC concluded by stating that vegetation management is not an area subject to rapid changes in methodology or technology and that the cost of another comparison of industry best practices would not be an effective use of resources.

557. Addressing UCG, YEC clarified that it is expected to disclose its policies because once policies are adopted by the management of YEC, they are implemented and do not “wait upon YUB review.”²⁵⁶ The Board will refer to a corporate policy when assessing the prudence of forecast costs.

Views of the Board

558. The Board is satisfied that YEC conducted sufficient research into other jurisdictions and best practices and agrees that changes in brushing techniques and methodologies do not evolve rapidly enough to render the policy obsolete.

559. The Board considers that it is always incumbent upon YEC to review and update where and when necessary any policy it adheres to in providing service to its customers and this fact alone addresses any concerns expressed by parties. YEC’s Vegetation Management policy is not an exception to this concept. The Board expects that any necessary revisions to any policy under which YEC operates would be put forward in a future GRA.

560. The Board agrees with the position of YEC that the current Vegetation Management policy reflects the brushing and vegetation practices of YEC that are relevant to the testing of the prudence of the associated costs. The Vegetation Management policy included in YEC’s application as Appendix 3.1 is approved.

6.2.3 DSM accounting policy

561. In its application, YEC submitted its updated DSM accounting policy in accordance with Board Order 2013-01.

²⁵⁴ UCG reply argument, page 5, paragraphs 14, 15, PDF page 6; page 14, paragraph 62, PDF page 15.

²⁵⁵ YEC final argument, page 26, PDF page 28.

²⁵⁶ YEC reply argument, page 10, section 3.3.2, PDF page 13.

562. In the Order, the Board deferred its findings and directions with respect to the DSM accounting policy until the time both YEC and ATCO Electric Yukon had jointly filed a DSM plan as directed. In AEY's 2013-2015 GRA, the utilities' joint DSM plan was filed and subject to review by the Board and intervening parties. The Board's comments on the DSM plan were provided in Order 2014-06, and as a result, YEC's updated DSM plan was submitted in the current application as Appendix 5.2.²⁵⁷

563. In response to YUB-YEC-1-75, YEC clarified that the only change to the DSM accounting policy from the version filed in its 2012-2013 GRA was an edit to Section 2.3 noting that "qualifying expenditures will be closed out on an annual basis," as opposed to earlier wording now deleted.

564. In argument, YEC reiterated that the DSM accounting policy was essentially unchanged from the version reviewed as part of the 2013-2013 GRA and further confirmed that the "policy addresses only the accounting treatment of DSM costs. For deferred costs to be included in rates these costs must first be reviewed by the Board as part of a GRA process. YEC is required to file an application with the YUB any time it seeks to adjust rates due to changes in revenue requirement."²⁵⁸

565. No party raised any issues with respect to YEC's proposed changes to its DSM accounting policy.

Views of the Board

566. The Board finds that the proposed DSM accounting policy, as submitted in its revised form in the current application, has addressed the comments of the Board in Order 2013-01. The Board approves the DSM accounting policy submitted by YEC in its application as Appendix 5-2.

²⁵⁷ YEC application, pages 1-10, PDF page 26 and Appendix 5.2, PDF pages 241, 242.

²⁵⁸ YEC final argument, page 45, PDF page 46.

Appendix A – Summary of Directions

This section is provided for the convenience of readers. In the event of any difference between the directions in this section and those in the main body of the decision, the wording in the main body of the decision shall prevail.

1. The Board is of the view that the information to be used in setting rates should reflect the best information available at the time of the hearing. While the Board understands that YEC determines the wholesale forecast after running its own regression analysis and management's own growth expectations, the Board is of the view that AEY may have more up-to-date information that may more accurately reflect the expected actuals. As a result, the Board directs YEC to use the actual wholesale sales to AEY for 2017 in the amount of 328.4 GW.h. For the 2018 wholesale forecast, the Board observes the difference of 19.4 GW.h between the 2017 actuals and the 2018 forecast. No explanation was provided for this difference. Considering that wholesales were forecast at 309 for 2017 and 309.5 for 2018, the Board is concerned about the reasonableness of the forecast for 2018. Therefore, the Board directs YEC to use the 2018 AEY Compliance amount of 314.7 GW.h for the 2018 forecast.....Paragraph 38
2. Additionally, several interveners expressed concern regarding the communication between YEC and AEY. While YEC submitted that additional communication would not have resulted in better forecasts for 2017 and 2018, the Board has noted the differences in the forecasts of YEC and AEY. Therefore, the Board directs YEC to refine its methodology to ensure its forecasts align closely with AEY's forecasts in future GRA submissions. Consequently, YEC is directed in its compliance filing to this decision to reflect actual wholesale sales of 328.4 GW.h for 2017 and forecast wholesale sales of 314.7 GW.h. for 2018. Paragraph 39
3. The Board is of the view that the most accurate and current information available at the time of the hearing should be used to make a decision on an application. Accordingly, the Board directs YEC to update its major industrial sales forecast in its compliance filing to account for the 2017 actuals and the updated 2018 Minto sales forecasts indicated in the undertaking.....Paragraph 46
4. The Board is of the view that the most accurate and current information available at the time of the hearing should be used to make a decision on an application. Accordingly, YEC is directed to update 2017 for the actual firm retail sales. For 2018, the Board accepts the explanations given by YEC and finds that YEC's firm retail sales forecast for 2018 is reasonable.....Paragraph 51
5. While YEC explained that it, and not ratepayers, will bear the total impact of these sales revenues being less than forecast, the Board is of the view that the most accurate and current information available at the time of the hearing should be used to make a decision on an application. As a result, the Board directs YEC to update the secondary sales forecast in its compliance filing to reflect the 2017 actuals and updated 2018 forecast that

YEC indicated it used in its updated revenue requirement in Undertaking 36.
.....Paragraph 55

6. Based on its view that the most accurate and current information available at the time of the hearing should be used to make a decision on an application, the Board directs YEC to update the generation forecast in its compliance filing to reflect the 2017 actuals and updated 2018 forecast that YEC indicated it used in the updated revenue requirement in Undertaking 35 and 36.....Paragraph 60
7. Given the above-noted advantages and disadvantages of LTA and ST hydro generation forecasts, the Board finds that, for purposes of this proceeding, it will not use the ST forecast for forecasting levels of hydro electric generation and thermal generation nor direct its use for future GRAs. In determining the revenue requirements for these and future test years, the Board is focusing on the reasonableness of the forecasts and forecasting accuracy. Further, the onus is on YEC to adequately explain any variance between actual results and its forecast amounts. For these reasons, the Board directs YEC in future GRA filings to show actual hydro and thermal generation results when comparing previous and forecast test years. Paragraph 77
8. The Board finds that proceeding in this manner will afford parties with the opportunity to examine any variances between 2016 and 2017 actual results, as well as variances between 2017 actual and forecast results in the compliance filing while still maintaining the ability of the Board to rely on the best available information at the time it renders its decision. To that end, where the discussion contained in subsequent sections of this decision has observed measurable variances between 2016 and 2017 actual results, or variances between 2017 actual and forecast results, YEC is directed to provide the applicable variance explanations in its compliance filing to this decision. ...Paragraph 88
9. As earlier stated in paragraphs 87-89, the Board is relying on 2017 actual results for the 2017 test year. However, the 2017 thermal generation amounts must be based on actual thermal generation fuel costs, not modelled results. Thermal generation fuel costs will be based on actual thermal generation output for the year and the costs required to produce that output. It is unclear if the fuel costs in Table 3 above represent actual costs or modelled costs. Therefore, YEC is directed in its compliance filing to this decision to reflect actual fuel costs for 2017. For the 2018 test period, YEC is to use the fuel costs related to YEC's forecast for 2018. Paragraph 100
10. In terms of the fuel mix, several different fuel mixes have been presented to the Board for the 2018 forecast. Consequently, the Board directs YEC, in its compliance filing, to state which fuel mix it is using for its 2018 forecast.....Paragraph 102
11. With respect to FTEs, notwithstanding that the table above (Table 11) illustrates that there have been minimal FTE increases forecast between 2016 actual and 2017 forecast, the Board considers that it requires actual 2017 FTE information in order to make a final determination on FTEs. YEC is directed to provide this information by way of updating the information found in Table 8 for 2017 actual FTE results. Paragraph 129

12. Further, the Board agrees in principle with YEC’s proposed update to its capital-to-maintenance allocation to a ratio of 18:82 based on recent trends. However, the Board directs this ratio be determined based on the inclusion of 2017 actual capital-to-maintenance results and for YEC to provide the updated 2017 ratio and, further, to clarify whether, based on this updated ratio, a change from its proposed 18:82 capital-to-maintenance ratio is required for the year 2018 in its compliance filing to this Order.
.....Paragraph 130
13. With respect to the labour escalation per cents relied on for labour-cost forecasting purposes in the amounts of 2.0 per cent and 1.75 per cent for the years 2017 and 2018 respectively, the Board directs YEC to provide 2017 actual labour escalation amounts for information purposes in its compliance filing to this Order. Paragraph 131
14. Where the directions contained in this order result in measurable FTE variances between 2017 actual results and 2016 actual or 2017 forecast results, YEC is directed to provide the applicable variance explanations in its compliance filing to this decision.
.....Paragraph 132
15. Finally, concerning the CW’s request for a more complete picture of YEC’s total labour costs and FTE count, the Board agrees it would be helpful to have this supplementary labour information available in a central location from the outset of YEC’s application. The Board directs YEC in its next GRA to complete the labour schedule identified by CW in its evidence in as much detail (for both cost and FTE) as is applicable to YEC and to submit the information as an additional schedule within YEC’s existing Tab 7 format.
.....Paragraph 133
16. Based on the evidence and variance explanations provided therein, the Board is prepared to accept both YEC’s 2017 actual results and the 2018 forecast. However, in the compliance filing to this decision, YEC is directed to update the information found in Table 12 for 2017 actual production costs by cost category.....Paragraph 140
17. YEC is directed to provide this detail by way of updating the information found in tables 13, 14 and 15 for 2017 actual transmission and distribution results in its compliance filing to this decision and to explain any variances as directed by the Board in paragraph 89. YEC is also directed to provide in its compliance filing the Actual 2017 closing balance of its Deferred Vegetation Management account and to clarify whether YEC deferred any 2017 actual costs in excess of \$0.502 million.....Paragraph 161
18. YEC is directed to provide this detail by way of updating the information found in Table 17 for 2017 actual results in its compliance filing to this decision and to explain any variances. Paragraph 167
19. Given the variance explanation provided by YEC and the minimal variance between 2016 and 2017 actuals, the Board is prepared to accept YEC’s 2017 actual administration cost amounts. However, in the compliance filing to this decision, YEC is directed to update

the information found in Table 18 for 2017 actual administration costs by cost category for information purposes. Paragraph 172

20. The Board is not persuaded by the UCG argument that a problem exists with respect to YEC’s “depreciation rates.” In response to an IR, YEC clarified that, with the exception of the two LNG assets discussed above, it has used only depreciation parameters and the implied depreciation rates that had been previously presented in a depreciation study, tested in a GRA, or specifically approved by the Board. The Board considers that YEC did not make a formal request for approval of its “depreciation rates” because it had not requested a change to any of the depreciation parameters that inform an implied depreciation rate. For these reasons, the UCG recommendation for denying a change in YEC’s depreciation rates is moot. Nonetheless, the Board considers that, given it has been eight years since the time of YEC’s last full depreciation study, it would be beneficial for a full depreciation study to be completed, so as to avoid the potential for large changes to depreciation expense that could be associated with incorporating material changes to asset service lives. YEC is directed to submit a full depreciation study at the time of its next GRA. Paragraph 212
21. The Board, however, does agree with the UCG observation that detail with respect to YEC’s depreciation expense calculations was not easily obtained. It was not until asked a second time to provide the detailed depreciation and amortization expense calculations that YEC responded with the requested information. The Board considers this information to be essential in facilitating a review of YEC’s depreciation and amortization expense irrespective of whether or not a change in depreciation parameters has been requested. YEC is directed to provide detailed depreciation and amortization calculations in all future GRAs consistent with the attachments provided with its response to YUB-YEC-2-27. This information may be included as an additional schedule within YEC’s existing Tab 7 format. Paragraph 213
22. The Board approves YEC’s actual 2017 and forecast 2018 depreciation and amortization expense amounts, subject to any findings made elsewhere in this decision with respect to capital additions or specific deferral or reserve accounts. The Board directs that any findings made elsewhere in this decision that will affect YEC’s depreciation and amortization expense calculation to be incorporated in its compliance filing to this decision. Paragraph 214
23. It is the Board’s view that YEC’s management and reporting of deferral and reserve accounts has led to unnecessary inefficiencies and confusion with respect to the processing of its application. For this reason, the Board directs YEC to re-establish its standard of disclosure to one that is transparent, consistent and provides cross-referencing among each of the interrelated rate base and revenue requirement items and the individual components comprising each item. This applies equally to the disclosure on YEC’s Tab 7 schedules and any supplementary information within YEC’s application. Paragraph 226

24. In Board Order 2013-01, the Board directed that a formulaic approach be used for forecasting future costs of debt. This direction was not followed. The Board reiterates the direction and expects this direction to be followed. In future GRAs, both Yukon utilities are to provide their cost-of-debt forecast based on the formulaic approach (long-term Canada bonds plus 120 basis points). If a utility chooses to employ a market-based approach, that utility must also provide a forecast based on the approved formulaic approach. Paragraph 238
25. Based on principles developed in Decision 2017-01²⁵⁹ and in terms of risk premium relative to the BCUC benchmark utility (FEI), the Board awards YEC 25 basis points for its small size. Further, in recognition of YEC's risks for generation, isolated grid and customer diversity, the Board awards YEC an additional 20 basis points for a total risk premium of 45 basis points above the BCUC benchmark utility. The Board finds that the additional 20 basis points acknowledges the overall risk of YEC as being greater than that of FortisBC (Electric) and greater than that of AEY. The Board does not accept the 57 basis point premium requested by YEC, because the Board, based on the evidence in this proceeding, does not accept PNG-West as an appropriate comparator to YEC. The Board considers, relative to the BCUC benchmark, that a 45 basis point risk premium for YEC is fair and reasonable. Paragraph 283
26. Lastly, YEC has stated it will assume all risk with respect to the thermal fuel mixture (LNG versus diesel). Therefore, the Board directs YEC to ensure that any variances due to changes in the thermal fuel mixture (forecast versus actual) are not included in the DFPVA. YEC is to indicate, in its compliance filing to this application, the steps it will take to prevent changes in the thermal fuel mixture from appearing in the DFPVA. Paragraph 293
27. For these reasons, the Board directs YEC to create a deferral account that records the variance between actual thermal generation fuel costs (based on volume only) and the GRA forecast thermal generation fuel costs (based on volume only) that are due to changes in water conditions. Factors such as equipment failure, force majeure, capital or planned maintenance events are not to be included in the calculations for this deferral account. YEC is directed, in its compliance filing to this decision, to propose trigger levels (+/-) that will initiate a rider proceeding to dispense with the balance in the deferral account. Paragraph 321
28. The difference between the directed deferral account above and YEC's proposed DCF is that the deferral account will be adjusted for those variances between approved forecast and actual, not modelled, results. In other words, the deferral account will be adjusted for changes in hydro generation that are a result of changes in water availability. YEC is directed, in its compliance filing, to explain the method it will use to determine the variance in hydro generation due to water availability. The Board directs that the deferral account be named the Low Water Reserve Fund (LWRF) as it will incorporate a broader

²⁵⁹ Board Order 2017-01, Appendix A: Reasons for Decision, AEY 2016-2017 GRA, April 27, 2017, page 40, section 8.1.4.3 starting at paragraph 202, PDF page 41.

range of thermal generation. YEC will adjust the balance in the LWRF on an annual basis for the difference in forecast thermal generation from actual thermal generation based on forecast load and only adjusting for the changes in hydro generation that are a result of changes in water availability.....Paragraph 322

29. To draw from the LWRF due to low water levels, YEC will have to submit an application to the Board requesting a drawdown of the fund indicating that the application is due to changes in hydro generation because of changes in water levels from those contained in the last Board-approved forecast. YEC will take the forecast risk for incremental generation costs for incremental loads outside of the forecast period with the exception of incremental load covered by the ERA. YEC is directed to amend its DCF term sheet to comply with these directions. Conversely, when the fund requires replenishment, YEC can apply to the Board for rate rider to replenish the LRWF. YEC, in its compliance filing, may submit any potential ceiling for the LWRF rate rider. Paragraph 323
30. YEC's DCF is currently at or around its cap of \$8,000,000. This balance in the DCF is to be transferred in its entirety to the LWRF. The Board is not persuaded by the submissions of parties that a change in the cap is required because to date it has not been used to refund customers, and customers would have to wait longer for such refunds if the cap was increased. This would not be a fair outcome. Paragraph 324
31. YEC is directed, in its compliance filing to this decision, to provide further details on how this LWRF will operate.....Paragraph 325
32. The Board accepts the submissions of YEC on wholesale rate matters. The UCG submissions ignore the requirements of OIC 1995/90 and is therefore rejected by the Board. The AEY position of paying YEC ERA amounts as it collects those amounts from customers lacks detail as to how such a process would be implemented and is also rejected by the Board. Given the Board's determinations with respect to the LWRF, YEC is directed to amend the ERA portion of Rate Schedule 42 to ensure it is in compliance with those directions. Paragraph 341
33. To be clear, ERA billing or refund amounts will be based on a consistent definition of costs. In this decision, the Board has clarified that actual costs for both the LWRF and the ERA are those costs related to actual thermal generation and not forecast thermal generation. Further, if significant industrial load enters or leaves the Yukon Integrated System or there are material changes in generation assets where either or both of these factors change the baseload generation mix, YEC can propose changes as to how the LWRF and the ERA operate at that time. Paragraph 342
34. YEC is directed to make the changes requested in this section in its compliance filing to this decision. Paragraph 343
35. The Board also notes that, in Undertaking 35, YEC noted that mid-year net rate base is within 0.2 per cent of the GRA forecast. However, YEC did not provide 2017 actuals for

capital costs on a project-by-project basis. Accordingly, the Board directs YEC to update its costs for each project in the compliance filing to this decision. Paragraph 356

36. However, any portion of this project that results from improper work done as part of the 2011 project requires further consideration. As noted by YEC during the oral hearing and in IR responses, some of the work in the current project is to replace the clamps used to mount the cabling, because the clamps used did “not meet modern standards for supporting long runs of vertical rise cable, nor is it appropriate for keeping the cables in place under the significant magnetic forces of a major fault.” In the view of the Board, it was imprudent of YEC, as part of its 2011 project, to use clamps that do not meet modern standards for this use. Accordingly, the Board disallows \$200,000 of the costs for the Aishihik elevator shaft steel rehabilitation project. The Board directs YEC to reflect this direction in its compliance filing to this decision. Paragraph 369

37. With respect to the AH reactor cable replacement, YEC stated that the cables were replaced in 2011 but that the cables are undersized and needed to be replaced. In response to a Board IR, YEC stated that the reactor cable replacement was not part of the original 2011 project scope of work and was the result of a change order caused by design complications. According to YEC, a length of wire removed as part of the project was repurposed for the reactor cable. The wire was deemed to be adequate for an air-free installation but was instead placed in an underground conduit. The Board is of the view that YEC acted imprudently in its 2011 replacement of the reactor cable and that ratepayers should not be asked to pay the costs of fixing work that was improperly done only seven years ago. Accordingly, the Board disallows the \$0.075 million that YEC has proposed to include in its rate base for the AH reactor cable replacement and directs YEC to reflect this in its compliance filing. Paragraph 373

38. With respect to the AH3 lube oil pump battery installation, YEC submitted that failure to install this backup installation increases the risk of the AH0 backup battery bank being drawn down too quickly, which could compromise the ability to recover the plant following an extended outage. In response to a Board IR, YEC added that the main battery is designed to last 16 hours, but the additional draw of the lube oil pump reduces that to approximately one hour. YEC added that a one-hour station service outage is unlikely, but the consequences of fully discharging the battery are severe. The Board accepts that the estimated 15-hour reduction in the backup battery bank’s ability to service station components is significant and warrants installation of a battery dedicated to the lube oil pump. Accordingly, the Board finds that the lube oil pump battery installation is needed and approves this component of the project. However, before approving the reasonableness of the costs, the Board directs YEC in its compliance filing to provide the 2017 actual costs for this component of the project. Paragraph 378

39. The Board directs YEC to update its 2017 costs for these projects to reflect 2017 actuals and to reflect the other findings in this section in its compliance filing. YEC, in the compliance filing, is also to indicate when it proposes to add these costs to rate base. Paragraph 381

40. In the application, oral hearing and IR responses, YEC clearly linked the satellite installations for SCADA and fibre communications upgrades to creating redundancy for disaster planning. YEC’s application also states that the network access controls are needed due to changes resulting from the satellite installations and that the SCADA communications upgrades will facilitate satellite communication at YEC’s various sites. Therefore, the Board finds that the satellite installations for SCADA, fibre communications upgrades and network access controls are necessary as part of YEC’s disaster recovery planning and approves these projects. The Board notes that, based on the response to YUB-YEC-1-67, there have been no cost changes since the estimates provided in the BBA assessment. Nonetheless, the Board directs YEC to include all actual costs for 2017 for all capital projects as part of its compliance filing to this decision. Paragraph 395
41. The Board has reviewed each of these major capital projects and the supporting evidence on the record of this proceeding. The Board considers that each of these projects is necessary and the associated costs are prudently incurred by YEC. However, the Board notes that the Hydro unit #WH4 overhaul, T&D – breaker replacements include 2017 costs that must be updated for actuals. Accordingly, the Board directs YEC to update its 2017 costs to reflect 2017 actuals for those projects, in its compliance filing to this decision. Paragraph 421
42. The hydro unit #MH2 overhaul, T&D – line replacement, Wareham spillway gate hoist replacement and Whistlebend supply/Takhini upgrade do not include costs for 2017. YEC is directed to reflect the 2018 forecast costs for these projects in its compliance filing. Paragraph 422
43. YEC provided no information on the specific activities that will be carried out as part of this assessment. Given that YEC has already observed that the deck timbers are worn and rotting and some of the support beams are crushed and “are in danger of failing completely,” the Board is of the view that the amount of \$325,000 simply to assess the structure is excessive and, in this case, is not necessary before taking action on the repairs or replacement. The Board is of the view that the funds would be better spent carrying out the repair or replacement. Therefore, the Board denies YEC’s proposed \$325,000 for the current test period and directs YEC to reflect this finding in its compliance filing. Paragraph 426
44. In the 2016 Resource Plan, YEC lists two diesel units at Faro, one of which is scheduled to be retired in 2021 and the second in 2040. Interveners did not provide any comments on this project. YEC did not provide any evidence on the frequency of the overheating issue and did not indicate whether the project could be deferred until 2021 when one of the diesel units is to be retired. YEC is directed to provide information in its compliance filing on the frequency of the overheating issue and whether the project could be deferred until 2021 when one of the two diesel units is to be replaced. Further, YEC is to state in its compliance filing if the 2021 unit replacement will require additional alterations to the Faro diesel building.....Paragraph 428

45. The Board accepts that these costs are reasonable and prudent. Accordingly, the Board approves this project and directs YEC to update the associated costs to include 2017 actuals in the compliance filing to this decision. Paragraph 432
46. The Board notes that this project was included and approved in YEC’s 2012-13 GRA, however, it now appears that this work was not completed by YEC, and YEC has not provided any explanation for not carrying out this project. Given that YEC has provided no evidence indicating that the transformer was improperly constructed in 2004, and given that this project was approved but not carried out in the subsequent six years since approval, the Board does not accept YEC’s submission that this project is necessary to address safety concerns. As such, the prudence of the related costs has not been shown. Consequently, the Board denies the inclusion in rate base of YEC’s proposed \$200,000 for this project and directs YEC to reflect this finding in its compliance filing.
.....Paragraph 435
47. The Board accepts that it is necessary for YEC to engage in ongoing work at its substations to ensure safe and reliable service and therefore approves this project as applied for by YEC. However, the Board directs YEC to update the costs for this project to include 2017 actuals in the compliance filing to this decision. Paragraph 437
48. However, in subsequent GRAs, when requesting approval of any such upgrades, the Board directs YEC to include a detailed description of the work that has been carried out or will be carried out at each substation and more detailed explanations of the need for the work at each substation. Paragraph 438
49. The Board considers that this project is necessary for the safe and reliable operation of the electrical system and that the costs are reasonable. Therefore, the Board approves this project and directs YEC to update the associated costs to include 2017 actuals in the compliance filing to this decision. Paragraph 440
50. The Board notes that YEC has not provided information on the amount of time that would be saved during outages nor the subsequent operating cost savings resulting from eliminating the need for an operator to travel six kilometers to the substation. Therefore, the Board finds that YEC has not sufficiently demonstrated that this project is reasonable and prudent and, as such, that it would be reasonable to incur such costs. Accordingly, the Board denies YEC’s proposed inclusion in rate base of the \$115,000 associated with this project and directs YEC to reflect this finding in its compliance filing..Paragraph 442
51. The Board agrees that it is reasonable for YEC to replace end-of-life components in its buildings and facilities. However, in order to approve the related costs, additional information is needed on which of the replacements are needed as a result of components being at end of life and which are being upgraded only to meet changes to codes. Accordingly, the Board directs YEC to file, as part of its compliance filing, a detailed itemized list of the work done or proposed to be done as part of this project, a description of each item, the costs for each item and the reasons why each item must be done. The reasoning for each item should include an explanation of whether it is an end-of-life

replacement or if it is bringing the component up to current codes and, in the case of the latter, a reference to the relevant code and an explanation of why the component needs to be brought up to code at this time. Paragraph 444

52. YEC did not provide information on whether cost reductions would be achieved by installing the data concentrator. In addition, YEC did not explain the benefits of adding remote diagnostic capability at the substations. Therefore, the Board finds that YEC has not shown the need for the installation of the data concentrator. The Board therefore finds that the related costs are not reasonable. Accordingly, the Board denies YEC's proposal to include \$165,000 in its rate base related to the Stewart-Minto local SCADA project and directs YEC to reflect this finding in its compliance filing. Paragraph 446

53. YEC proposed a number of other capital projects between \$100,000 and \$1 million. The Board has reviewed YEC's proposals for the Aishihik generator fire protection, Aishihik tailrace road and slope, Canyon Lake control structure and dyke refurbishment to implement dam safety recommendations, Whitehorse diesel system grounding for generators, Whitehorse local HMI/historian upgrade, L170 line access, S-150 – Whitehorse main RTU upgrade, Whitehorse-Aishihik-Faro transmission upgrades, 25 kV distribution cut-out replacement, customer extensions, Aishihik emergency signage and lighting upgrade, critical spares – system requirement, Dawson derrick digger, fencing upgrades – various sites, Mayo B door installation for crane inspection, Mayo transient trailer unit, vehicle purchases, voice repeater site for Little Salmon Area, voice repeater site for Mendenhall/Champagne and WRGS hazardous materials containment projects. The Board is satisfied that these projects are needed to ensure safe and reliable electrical service and that the related costs appear to be reasonable. Accordingly, the Board approves these projects but notes that many of them include forecast costs for 2017 that must be updated to reflect 2017 actuals. Therefore, the Board directs YEC to update, in its compliance filing, 2017 costs to reflect 2017 actuals for all of the projects listed above that include forecast costs for 2017. Paragraph 447

54. Further, the Board is of the view that, at this time, the technology used for battery storage has not been tested in northern climates such as Yukon and has not been shown to provide the benefits outlined by YEC in such jurisdictions. The Board finds that, given the costs and unproven nature of the technology in a northern environment, the project is not viable. If YEC did not have funding from NRCan, it was risky to undertake the project, considering that even the initial costs in the test years are forecast at over \$9 million dollars. For these reasons, the Board finds that expenditures on such a project are not warranted. As a result, the Board denies the inclusion of costs associated with the battery energy storage project in the revenue requirement for the test years and directs YEC to reflect this finding in its compliance filing. Paragraph 463

55. Given the above, the Board accepts Mr. Maissan's recommendation that YEC provide a detailed comparison of alternatives for this project, including the pros, cons, capital costs, operating costs and timeline to in-service and justification for its preferred option. Accordingly, before undertaking any further costs on this project, the Board directs YEC to provide this information in any future application for this project. Any costs incurred

to date for this project are to be held in WIP until such time as a new application is brought before the Board and the Board makes a determination on that application and the prudence of the costs incurred. Paragraph 471

56. Despite the Board determination that DSM projects were only approved up to 2015, YEC has continued with program expenditures beyond that point and has forecast continued DSM expenses during the test period. YEC did not make an application to the Board before expanding DSM programs beyond 2015. Accordingly, the Board finds that any DSM program expenditures that occurred after 2015 were not prudently incurred and are disallowed for inclusion in YEC’s rate base. Paragraph 478

57. YEC also incurred expenses on DSM projects that do not fall within the three projects approved by the Board in Order 2014-06, despite the Board’s explicit statement that YEC must apply to the Board before expanding its DSM program beyond the elements approved in that order. Accordingly, the Board finds that YEC’s DSM expenditures on programs not approved in Order 2014-06 (LED lighting, automotive heater timing rebates and low-cost energy efficient products) were not prudently incurred and are disallowed for inclusion in YEC’s rate base. Paragraph 479

58. Although the Board made the above-noted finding in relation to AEY, YEC should have taken note of this finding, because such a finding equally applies to YEC. As a result, the Board considers that retrofitting streetlights at end of life with LED lights were prudent expenditures. Any LED installations that are not end-of-life conversions must not be included in YEC’s rate base. Paragraph 481

59. The Board is not persuaded that YEC should continue to operate DSM projects. YEC has indicated the benefits of expanding the program and submitted that its programs have met or exceeded key performance indicators. However, the Board notes that the Yukon government has DSM incentive programs in place, and the Board is of the view that it is better to leave DSM projects to government, rather than having ratepayers fund these projects. For these reasons, the Board is of the view that continuation of DSM programs by YEC is not necessary. Accordingly, the Board denies YEC’s requests to continue with any DSM programs other than end-of-life streetlight conversions as discussed above. Paragraph 482

60. The Board directs YEC to reflect the Board’s findings with respect to DSM programs, as detailed above, in its compliance filing. Paragraph 483

61. The Board acknowledges that when the first resource plan was approved, the Board asked YEC to update it in five years. However, the Board also notes that the same was not requested when YEC updated the resource plan in 2016. The Board accepts that the 2016 update of the resource plan provided benefits in the form of long-term planning, risk assessment and stakeholder engagement. The Board therefore accepts that YEC’s costs for the 2016 update were prudently incurred and approves YEC’s proposal to amortize those costs over five years. However, the forecast costs must be updated to reflect 2017

actual costs, and the Board directs YEC to do so in its compliance filing to this decision.
.....Paragraph 489

62. However, the Board is of the view that it is not prudent for YEC to continue with these significant expenses to update the resource plan every five years. Accordingly, the Board directs YEC to seek Board approval prior to any future updates of its resource plan. Any such application must be accompanied by a detailed proposal for both costs and scope of work, including a description of work to be carried out internally and by consultants. YEC must also include an explanation of why any work to be done by consultants cannot be carried out by internal staff. Paragraph 490

63. Accordingly, the Board directs YEC to include in its compliance filing a detailed breakdown of any costs incurred after September 2014 for the Gladstone diversion project and to reflect the removal of those costs from the amount that YEC proposes to amortize for the Gladstone diversion project. Paragraph 497

64. In response to a UCG IR, YEC indicated that the 35 years of data inflows into YECSIM reflect what was recorded over the 35 years, including any climate change impacts relevant to those years. Given YEC's statement that its YECSIM model includes climate change impacts, the Board finds that YEC has not adequately demonstrated that it is necessary to engage in a separate study specifically on climate change impacts. Accordingly, the Board finds there is no justification for this project and directs YEC to remove these costs from its revenue requirement for each of 2017 and 2018 and not recover the 2016 costs. The Board directs YEC further to reflect this finding in its compliance filing. Paragraph 513

65. In response to a UCG IR, YEC indicated that the 35 years of data inflows into YECSIM reflect what was recorded over the 35 years, including any climate change impacts relevant to those years. Given YEC's statement that its YECSIM model includes climate change impacts, the Board finds that YEC has not adequately demonstrated that it is necessary to engage in a separate study specifically on climate change impacts. Accordingly, the Board finds there is no justification for this project and directs YEC to remove these costs from its revenue requirement for each of 2017 and 2018 and not recover the 2016 costs. The Board directs YEC further to reflect this finding in its compliance filing. Paragraph 516

66. The Board finds that YEC has not provided information that persuades the Board that a study on smart grid and time-of-use rates is useful or needed. Accordingly, the Board directs YEC to remove any forecast expenditures and cost recovery related to this project in its compliance filing to this decision. Paragraph 519

67. Given that YEC has indicated that it will not be taking any action to move the two plants in the near future, the Board considers that YEC has not sufficiently demonstrated the need for the study at this time and that the associated costs are reasonable. Accordingly, the Board directs YEC to remove any forecast expenditures and cost recovery related to the northern diesel plant location study. Paragraph 525

68. The Board considers YEC has not adequately quantified the expected benefits and costs of uprating the Whitehorse hydro units in order to justify an expense of this magnitude for an investigation. Accordingly, the Board denies YEC's proposed Whitehorse hydro uprate project and directs YEC to remove any forecast expenditures and cost recovery related to this project in its compliance filing.....Paragraph 527
69. The Board finds that YEC has not adequately quantified the benefits and costs of a small hydro project in order to justify an expense of this magnitude on the prefeasibility stage assessment. The Board is of the view that small hydro is better left to other entities such as independent power producers. Accordingly, the Board denies YEC's proposed small hydro project and directs YEC to remove any forecast expenditures and cost recoveries related to this project in its compliance filing.....Paragraph 529