Yukon Utilities Board

Board Order 2013-01
Appendix A: Reasons for Decision
March 25, 2013

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1 Introduction

1. On April 27, 2012, Yukon Energy Corporation (YEC, Company or Applicant) filed with the Yukon Utilities Board (the Board) an application, pursuant to the *Public Utilities Act* and *Order-in-Council 1995/90*, for approval of its forecast revenue requirements for the 2012 and 2013 test years, approval of interim retail rates for 2012, changes to update and reactivate the Diesel Contingency Fund (DCF) as of January 1, 2012, related rate adjustments to Rate Schedule 42 and required updates and changes to depreciation rates and planning cost accounting policies (Application).

2. YEC is the main generator and transmitter of electrical energy in the Yukon providing transmission facilities for the Whitehorse-Aishihik-Faro (WAF) and Mayo-Dawson (MD) grid systems which have been joined by the Carmacks-Stewart transmission system through stages 1 and 2 of the Carmacks-Stewart Transmission Project (CSTP). YEC supplies power through wholesale electricity sales to the Yukon Electrical Company Ltd. (YECL).

3. YEC is seeking approval of a revenue requirement of $39.859 million for 2012 and $45.641 million for 2013.[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 $2.203 million for 2012 and $3.113 million for 2013 plus approval to adjust diesel process used in setting fuel costs to reflect current forecast conditions, approving changes to the DCF as outlined in Appendix 3.2 of the Application, and accepting the diesel generation forecast at 66 percent of long-term average annual levels in 2012 and 59 percent of long-term average annual levels after 2012.
- Non-fuel operating and maintenance costs forecast of $17.496 million for 2012 and $18.385 million for 2013 including approval to apply $0.398 of the remaining Faro Dewatering Account liability amounts against the current outstanding balance in the Reserve for Injuries and Damages account (RFID), approval of a new RFID policy as outlined in Appendix 3.1 of the Application, and approval to directly credit any secondary sales revenue directly to the DCF.
- Approval of depreciation and amortization expense forecasts of $7.813 million for 2012 and $10.012 million for 2013 including approval for the new Planning Cost Accounting Policy and transition provisions contained therein as provided in Appendix 5.1 of the Application, approval for the new Demand Side Management Accounting Policy as provided in Appendix 5.2 of the Application. YEC further requested approval to reduce depreciation rates for fixed assets, an estimated placeholder of $1.100 million for the costs of the current GRA, and amortization of earlier regulatory and related costs as outlined on page 7 of the Application.
- Approval of mid-year forecast rate base costs of $223.020 million for 2012 and $241.738 million for 2013.

[1] Application, page 5. Amounts are before deductions of non-rate revenues.

- Approval of $12.345 million in 2012 and $14.130 million in 2013 for return on rate base based on an allowed rate of return on equity of 8.77 percent for each of 2012 and 2013 respectively.

4. The Application also sought approval of interim refundable rates effective July 1, 2012 through Rider J rate increases for retail and industrial customers. The Board approved interim rate adjustments of 6.4 percent for retail customers and 2.9 percent for industrial customers on a refundable basis effective July 1, 2012 by way of Rider J through Board Order 2012-05 issued June 7, 2012. YEC filed with the Board a further request for an interim refundable revenue shortfall rate rider (Rider R) of 6.5 percent effective January 1, 2013. The Board approved through Board Order 2012-10, an interim rate adjustment of 3.75 percent for firm retail and industrial customers on a refundable basis through implementation of Rider R effective January 1, 2013.

5. On May 4, 2012, the Board issued Board Order 2012-03 regarding the Application in which the Board ordered YEC to publish a Notice of Application and of a workshop for the General Rate Application (GRA) no later than May 9, 2012, 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 for inspection at its head office located at 2 Miles Canyon Road, Whitehorse, and to provide a copy of the Application and any supplemental information if requested by an intervener. Board Order 2012-03 proposed a proceeding schedule for the Application with a hearing to commence on September 17, 2012.

6. On May 22, 2012, 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 *Public Utilities Act* (Act).

7. YEC held a workshop on May 30, 2012 in Whitehorse, where the Application was reviewed and certain portions explained in greater detail.

8. The Board, through Board Order 2012-04, issued May 22, 2012, granted intervener status for this proceeding to the following:

- Yukon Electrical Company (YECL)
- John Maissan (Leading Edge or LE)
- Utilities Consumers' Group (UCG)
- Yukon Conservation Society (YCS)
- The City of Whitehorse (CW)

9. The proceeding schedule was amended due to a May 25, 2012 request by UCG and subsequent comments received by the Board from the applicant and registered parties. Board Order 2012-06, issued June 28, 2012, changed the process schedule and in turn the start date for the oral public hearing from September 17, 2012 to November 12, 2012.

10. The proceeding schedule was further amended through Board Order 2012-07, issued July 13, 2012, when YEC provided a request on July 3, 2012 for an extension for the time to answer information requests (IRs). The Board changed the dates for the

information responses from YEC, intervener evidence, IRs to interveners, information responses from interveners and YEC rebuttal evidence. The oral public hearing dates and the dates for final argument and reply argument did not change.

11. On August 1, 2013, UCG submitted a motion requesting that the Board issue an order requiring YEC to provide adequate responses to certain IRs submitted by UCG and identified in the motion. By way of memorandum dated August 3, 2012, the Board invited comments from YEC on the UCG motion and reply comments from UCG. The Board issued a further memorandum on August 15, 2012, suspending the proceeding schedule pending a ruling on the UCG motion. Board Order 2012-08, issued August 22, 2012, provided a ruling on the UCG motion and further amended the proceeding schedule by including steps for a second round of IRs to YEC, information responses by YEC on that second round of IRs as well as responses to IRs as directed by the Board in its ruling on the UCG motion. The proceeding schedule amendment also revised the dates for intervener evidence, IRs to interveners, information responses from interveners and YEC rebuttal evidence. The remainder of the proceeding schedule was unchanged.

12. On November 12, 2012, the Board held an oral public hearing in the City of Whitehorse, Yukon. The Board was comprised of the following: Bruce McLennan, Chair; Robert Laking, Vice-Chair; and members Andre Fortin and Naresh Prasad.

13. The Board directed parties to file final argument by November 28, 2012, and reply argument by December 12, 2012. The Board considers the proceeding closed on December 12, 2012.

14. 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.

2 Yukon energy system sales and generation

2.1 Overview

15. YEC is the main generator and transmitter of electricity in Yukon, accounting for over 90 percent of annual Yukon power generation and providing 138 kV and 69 kV transmission facilities for the integrated system (IS).[2]

16. Yukon Energy directly serves about 2,000 customers at the distribution (retail) level (about 11 percent of all electrical retail customers in Yukon), most of whom live in and around Dawson City, Mayo and Faro. Indirectly, Yukon Energy also provides power to Yukon retail customers served on the Integrated System (including those located in

[2] In June 2011, the Whitehorse-Aishihik-Faro and the Mayo-Dawson transmission grids were inter-connected through Stage 2 of the CSTP Stage 2.

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

17. YEC submitted that, since 2005, non-industrial grid load growth supplied by YEC to YECL and other grid retail customers has tended to be higher than forecast. YEC attributed the growth as an indicator of Yukon's economic expansion and other factors such as an increased reliance on electric heat.

18. Industrial sales under Primary Industrial Rate Schedule 39 currently include sales to the Capstone Mining Corp. (Minto mine) and Alexco Resource Corp. (Alexco mine). Industrial sales to Eagle Industrial Minerals (Whitehorse Copper Tailings or WHCT) are also forecast starting in 2013.

19. YEC hydro generation capability materially exceeded firm sales on both WAF and MD systems after the Faro mine closure in 1998 on the WAF system and the 1989 closure of the United Keno Hill mine on the MD system.

20. With continued load growth on the WAF system, YEC submitted that WAF surplus generation has declined markedly since the Faro and United Keno Hill mine closures. In the 2008-09 GRA, YEC noted that with the completion of CSTP Stage 1 and the connection of the Minto mine, the WAF system was reaching a point where the surplus hydro generation was almost depleted at certain times of the year.

21. YEC submitted that increasing reliance on diesel generation and the depletion of surplus hydro generation is evidenced by actual diesel generation exceeding forecast amounts over the period from 2009 to 2011.[3] Moreover, secondary sales have been interrupted on a sustained basis since September 2010, and as a result, a number of secondary sales customers have converted to primary supply for their electric heating loads.[4]

22. Notwithstanding the above, YEC submitted that the majority of grid generation requirements in the test years (over 97 percent) will continue to be met with hydro generation based on annual long-term average hydro generation capability. However, forecast diesel generation included in this Application is considerably higher than the levels approved in the 2009 GRA and the current Application marks a major transition in forecast annual long-term average baseload diesel generation needed to meet grid load growth. Anticipated continuing load growth beyond the test years is expected to result in continued material increases in diesel generation requirements, driving the need to secure new lower cost sources of supply by 2015 to displace continued increases in baseload diesel requirements.[5]

2.2 Sales forecast

23. YEC submitted that total forecast sales are 382.6 GW.h for the 2012 test year and 395.9 GW.h for the 2013 test year. In the table below, actual sales are indicated in

[3] Actual diesel generation exceeded forecast by 2.6 GW.h, 4.28 GW.h and 10.55 GW.h respectively in 2009, 2010 and 2011.

[4] Application, page 2-2.

[5] Application, page 2-3

the Ac column and approved sales in the Ap column for the years 2009 and 2010, preliminary actual sales are in the P column for 2011 and forecast sales are in the F column for the 2012 and 2013 test years.

Table 1. **Summary of energy sales (GW.h) 2009–2013**

Sales group	**2009** **Approved**	**2009** **Actual**	**2010** **Actual**	**2011** **Prelim.**	**2012** **Forecast**	**2013** **Forecast**
Industrial	29.0	29.4	30.3	43.3	52.3	62.4
Residential	11.2	11.7	11.4	12.7	12.3	12.4
General Service	19.5	19.7	22.7	21.3	21.7	22.6
Street & Space lights	.3	.5	.3	.3	.3	.3
Total YEC – Firm Retail	31.0	31.9	34.4	34.3	34.3	35.3
Total YEC – Firm Retail & Industrial	60.0	61.2	64.7	77.6	86.6	97.7
Wholesales	267.7	267.3	276.3	290.5	296.0	298.2
Total YEC - Firm	327.8	328.5	341.0	368.1	382.6	95.9
Secondary Sales	7.6	17.4	10.5	0.6	0.0	0.0
Total Company	335.4	345.8	351.5	368.7	382.6	395.9

Source: YEC Application, Table 2.1, page 2-17.

2.2.1 Wholesales sales to Yukon Electrical

24. As shown on the above table, YEC energy sales on the integrated system (IS) are primarily made up of firm wholesale sales to YECL.

25. YEC submitted that YECL each year provides YEC with an integrated system firm wholesale purchase power forecast that reflects YECL's forecast grid firm retail sales forecast less forecast generation from YECL's Fish Lake hydro plant. YEC subsequently reviews and adjusts YECL's forecasts in light of the most recent information available.

26. For this Application, YEC submitted that 2011 actual YECL wholesale sales were adjusted to reflect expected in-service of a new Fish Lake hydro Unit #1 in 2013, and to reflect adjustments for weather conditions based on 10-year average Heating Degree Days (HDD). A percentage growth increase of 2.26 percent per year was then applied to the adjusted 2011 actual wholesale sales (normalized assuming operation of both Fish Lake units) for each of 2012 and 2013 and additional sales were included for 2012, as a result of continuing shut down of Fish Lake Unit #1 until January 2013.

27. CW submitted that there were "…significant discrepancies between the Wholesale Sales of YEC and the wholesale Purchases of YECL"[6] and argued that YECL's was the more accurate forecast. Given the importance of wholesale sales to system sales, CW recommended that YEC should make an effort to understand and validate YECL's retail customer sales forecasts. As a result, CW requested that the Board direct YEC to adjust its total sales forecast of diesel generation[7], the DCF and any other adjustments that may be necessary.

6 CW final argument, section 5.

7 The City submitted that the wholesale sales forecast be 286,357 and 289,755 MWh, respectively for 2012 and 2013; CW final argument, section 6.

28. YECL submitted that it had reviewed YEC's wholesale sales forecast and was unable to reconcile it with its own forecasts. YECL pointed out that YEC's wholesale sales forecast did not properly account for the unavailability of Fish Lake generation. Moreover, YECL stated that YEC had applied weather normalization to a portion of the total sales leading to an understatement of wholesale sales volumes.[8]

29. UCG submitted that there was not enough information on the record to confirm YECL's agreement or disagreement respecting changes that YEC has made to YECL's forecast.[9] UCG pointed out YEC's acknowledgement that the Board has "…never approved the use of 10 year average Heating Degree Days as a method of normalizing temperature-sensitive sales forecasts."[10] UCG further submitted that YEC has not justified the use of a 10-year average and has not presented other methodologies to demonstrate that the 10-year average is superior to other methodologies.[11]

30. YEC submitted the intervener arguments that stated YECL was in the best position to forecast its retail customers' needs was not consistent with the evidence in the proceeding and should be rejected by the Board. The methods used for YEC's forecasts and the related interactions with YECL are on the record and have not been substantively challenged by interveners. Accordingly, YEC submitted that the forecasts as provided in the Application should be adopted by the Board, subject only to the correction noted in YEC's final argument.[12]

31. In reply argument, CW submitted that YECL had supported its argument regarding the inaccuracy of the wholesale sales forecast in that only YECL has the right to serve WHCT. Moreover, CW pointed out that, prior to the Order-In-Council, YECL had provided service to Whitehorse Copper. CW added that "…YEC has not cited any legislation regulation or Order-In-Council that may have amended or otherwise affected the scope of YEC's franchise." CW recommended that this issue be resolved as part of YECL's 2013 GRA proceeding if timing permits.[13]

32. In its reply argument, UCG submitted that the record of this proceeding shows that YECL is not in agreement with changes made by YEC to YECL's forecast. UCG further stated that this raises the issue as to how the Board should establish the load forecast associated with the wholesale class. UCG added that YECL, in its 2008-09 GRA, included "…statistical methods and weather normalization which makes it superior to YEC's."[14] Given the Board's acknowledgement of this statement in that decision, UCG submitted that either the Board should give more weight to YECL's forecast or direct the utilities to establish an agreed upon forecast. UCG also submitted

[8] YECL final argument, paragraph 19.
[9] UCG final argument, paragraph 148.
[10] CW-YEC-1-6(d). UCG final argument, paragraph 151
[11] UCG final argument, paragraph 151.
[12] "The forecast sales in the Application exclude provision for wheeling power over YECL's distribution system to serve WHCT… and this will be corrected in the compliance filing (along with the related correction to provide for increased purchased power by YEC to recover the power required for YEC's sales to WHCT)."; YEC final argument, wholesale sales forecast, page 15.
[13] CW reply argument sections 11 and 13
[14] UCG reply argument, paragraph 29.

that YEC should wait for a Board decision regarding who should be serving Whitehorse Copper Tailings.[15]

33. YEC argued that the methods used for YEC's forecasts and the related interactions with YECL are clearly on the record and have not been substantively challenged by intervener arguments or the evidence.

Views of the Board

34. In making its decision on the wholesale sales forecast, the Board considered YEC's submission that its "…updated wholesale forecasts for 2012 and 2013 using the best available information… [and] …adopting YECL's forecast … would result in a less accurate forecast … than that provided by YEC in the Application."[16] Moreover, the Board is not convinced by the evidence of the interveners that YEC's wholesale sales should not be adopted. The Board finds YEC's wholesale forecast reasonable.

35. However, the Board is of the view that YECL may have more up-to-date information regarding the unavailability of Fish Lake Hydro during the 2012-13 test period. The Board directs YEC to consult with YECL regarding the unavailability of Fish Lake Hydro during the 2012-13 test period and adjust its forecast if necessary in its compliance filing.

2.2.2 Major industrial sales

36. Table 1 shows that the majority of the energy sales increases over the 2012-13 test period is attributable to major industrial sales. The major industrial customers include:

- Minto mine, which came into service in late 2008
- Alexco mine, which came into service in late 2010[17]
- Whitehorse Copper Tailings (WHCT), which has forecast a mid-2013 in-service date

37. YEC submitted that no other new mine loads were forecast to connect to the IS within the test period. However, prior to filing this Application, YEC was informed that a developer near Dawson City "…would like to discuss connection to the grid … potentially by as soon as mid-2013."[18] Thus YEC submitted that it was pursuing this potential connection and would update the Board when there is more definitive information.

38. Interveners only took issue with WHCT, which will be discussed in the following section. Respecting the forecast Minto mine load, YEC submitted that there has been a material change to the 2012 and 2013 Minto sales forecasts. However, YEC was not amending its Application because cost and sales forecasts in an application should not to be adjusted to reflect events subsequent to the filing of the application.

15 UCG reply argument, paragraph 30.
16 YEC reply argument, pages 7 and 8.
17 Application, page 2-6; At this time due to uncertainty regarding the timing of future developments, power requirements for additional mines have not been included in the load forecast.
18 Application, page 2-7.

Views of the Board

39. 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. This allows all parties to make submissions on any new information. Accordingly, the Board directs YEC to update its major industrial sales forecast in its compliance filing to account for the change to the 2012 and 2013 Minto sales forecasts referred to in the hearing.

2.2.2.1 Whitehorse Copper Tailings

40. YEC acknowledged the key issue regarding WHCT relates to which utility should serve this industrial load.

41. In an interrogatory, YEC stated that it intended to supply WHCT and use the wheeling approach because "… It is Yukon Energy's view that Yukon Electrical does not have a franchise to serve industrial customers."[19]

42. Furthermore, YEC added that YEC has consistently served all major industrial customers in Yukon since securing its franchise in 1987. YEC submitted that YEC's 2013 revenue requirement will need to be increased if YECL, rather than YEC was to serve WHCT.[20]

43. CW submitted that it takes no position as to which utility should serve WHCT. Notwithstanding, CW submitted that the serving arrangements should be based on the most efficient and effective service to the customer with regard to net benefits to all customers of both utilities. However, CW stated that there was insufficient evidence for the Board to make a determination and CW recommended that the issue be resolved in a separate written proceeding wherein the net costs and benefits to end-use customers could be evaluated. Accordingly, CW recommended that the costs and revenues attributable to serving WHCT should be removed from the forecast in the compliance filing pending a Board hearing and decision on this matter.[21]

44. LE indicated that there appears to be no documentation or legislation as to which utility should serve WHCT. LE noted that YEC's evidence as to a necessary increase to its 2013 revenue requirement if YECL were to serve WHCT was predicated on YECL not filing a GRA. LE opined that the additional source of revenue might enable YECL to defer a GRA and thereby save the ratepayers some money. Moreover, the Board may have some options respecting the treatment of the additional YECL revenues. Accordingly, LE recommended that the Board decide which utility serves WHCT to ensure that ratepayers are not disadvantaged either way.[22]

45. UCG noted that YEC could not identify any legislation or documentation regarding its perceived entitlement to serve WHCT. In light of this, UCG submitted that it was redundant to have YEC serve a load to which YECL already has an existing line.[23]

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[19] YECL-YEC-1-20.
[20] YEC final argument, pages 18 to 19.
[21] CW final argument, Section 2.2, pages 4 to 5 3 to 4.
[22] LE final argument, page 5, section 7.
[23] UCG final argument, paragraph 167.

Further, UCG submitted that, to better inform its decision, the Board should direct both YEC and YECL to submit details of the costs and benefits to Yukon ratepayers if they are selected to be the service provider to WHCT.

46. YECL submitted that WHCT is located within YECL's deemed franchise area under Section 77(2) of the Act and that Section 1 of the Yukon Power Corporation Regulation (1987), O.I.C. 1987/071, that YEC may only have served in "…areas where the production, generation, storage, transmission, sale, delivery or furnishing of electricity is not already being provided by Yukon Electrical."[24]

47. YEC submitted in its reply argument that, without evidence that YECL will file a 2013 GRA, the only evidence on the record is YEC's which highlights the material benefits that ratepayers receive in having YEC serve WHCT.

Views of the Board

48. In making its determination, the Board considered Section 77 of the Act and Section 1 of the Yukon Power Corporation Regulation (1987). The Board also took note of YEC's acknowledgement that wheeling power over another's facilities can introduce some inefficiencies, i.e. administrative matters such as billing, as well as potential for duplication of work.[25] Further, in its testimony, YEC could only state that "…in general terms [YEC] believe[s] that industrial customers are customers of the generating utility, Yukon Energy."[26]

49. As a result of the above, the Board finds that YEC is not entitled to serve WHCT because it is a customer within the YECL franchise area and under Section 1 of the regulation, YEC cannot provide electrical service in areas where it is already provided by YECL. The Board therefore directs YEC in its compliance filing to remove WHCT volumes from its industrial sales forecast and include those volumes in its wholesale sales forecast for the test years and to adjust its revenue requirement accordingly.

2.2.3 Secondary sales

50. Since the Faro mine closure in 1998, WAF surplus hydro generation has been available for secondary sales; however, load growth over the period up until 2010 has reduced available surplus hydro. YEC submitted that, as a result, secondary sales have been interrupted on a sustained basis since September 2010, except briefly in September 2011 due to higher water in Aishihik Lake, which otherwise would have been spilled. Total secondary sales in 2011 were only 0.6 GW.h.

51. To the extent secondary sales become available in the test years, YEC proposed to credit the secondary sales revenue directly to the Diesel Contingency Fund (DCF). It is expected that secondary sales would only become available if there are higher water flows. YEC submitted that crediting any additional revenues on this basis is consistent with the principles underlying the DCF and would serve to stabilize revenues and rates in the test years.

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24 YECL final argument, paragraph 5.
25 YECL final argument, paragraph 8; Hearing Transcript Volume 1, November 12, 2012, page 116, line 25 to page 118, line 6.
26 Hearing Transcript, Volume 1, November 12, 2012, page 114, lines 9 to 11.

Views of the Board

52. The Board denies YEC's request to credit secondary sales revenue directly to the DCF for the reasons set out in Section 3.6 below. As a result, the Board directs YEC to forecast, manage and account for secondary sales (if there are any) as part of its energy sales. The Board directs YEC to reflect this finding and direction in its compliance filing.

2.3 Power generation

53. 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 diesel generation as required. Total generation is based on the sum of total sales plus losses, which are forecast at 8.7 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 – 2012-13**

Description	2009 Approved	2009 Actual	2010 Actual	2011 Prelim.	2012 Existing Forecast	2012 Proposed Forecast	2013 Existing Forecast	2013 Proposed Forecast
Sales and Losses								
Total Energy Sales	335,373	345,839	351,492	368,665	382,621	382,621	395,913	395,913
Losses - MWh	28,359	28,007	30,764	32,101	33,288	33,288	34,444	34,444
Losses -%	8.50%	8.10%	8.80%	8.70%	8.70%	8.70%	8.70%	8.70%
Total Generation	363,732	373,846	382,255	400,766	415,909	415,909	430,357	430,357
Source-MWh								
Hydro Generation								
Whitehorse	228,573	223,775	233,806	231,501	232,207	229,245	232,231	230,124
Aishihik	103,110	118,680	111,710	132,340	121,661	120,109	130,037	128,857
Mayo	30,613	28,507	31,528	20,588	59,533	58,774	60,977	60,424
Total Hydro	362,296	370,962	377,044	384,429	413,402	408,128	423,244	419,405
Wind Turbine	491	238	85	402	239	239	238	238
Diesel Generation								
Whitehorse	0	1,722	2,417	6,571	1,142	3,878	3,462	5,510
Faro	550	413	272	1,654	323	1,142	980	1,622
Dawson	395	509	2,404	7,170	802	2,522	2,432	3,583
Mayo	0	1	34	539				
Total Diesel	945	2,645	5,127	15,935	2,268	7,542	6,875	10,714
Source -%								
Hydro Generation	99.60%	99.20%	98.60%	95.90%	99.40%	98.10%	98.30%	97.50%
Diesel Generation	0.30%	0.70%	1.30%	4.00%	0.50%	1.80%	1.60%	2.50%
Wind Generation	0.10%	0.10%	0.00%	0.10%	0.10%	0.10%	0.10%	0.10%

Source: YEC Application, Table 2.2, page 2-18.

54. YEC forecast generation for the test years, as proposed in Table 2 above, is made up of 98.1 percent and 95.7 percent hydro, respectively in 2012 and 2013, with diesel comprising 1.8 to 2.5 percent of total system generation throughout the test period.

55. YEC submitted that the integrated WAF and MD system has 92 MW of installed YEC hydro generation, of which approximately 72 MW can be relied upon for the winter peak load. Furthermore, because of the predominance of hydro generation on the Yukon system and the isolation of the integrated grid from other grids outside the territory, YEC submitted that other forms of backup capacity are required to supplement hydro in order to meet the integrated system's winter or spring seasonal generation constraints and to provide reliable energy generation in drought years. As grid load increases, YEC submitted that there is an increased reliance on diesel generation to meet baseload energy requirements in winter and early spring.[27]

56. Between 1998 and 2008, the existing diesel infrastructure was utilized primarily as reserve capacity to meet peak or short-term emergencies. YEC forecast diesel generation to be on the margin during the 2012-13 test period. As a result, YEC submitted that past stabilization mechanisms such as the DCF, the energy reconciliation adjustment (ERA) provisions of rate schedule 42, or other rate design mechanisms were once again relevant and important. However, because of significant changes to the integrated grid, YEC submitted that the DCF and ERA provisions require updating prior to their reactivation. YEC, in the Application, therefore, included steps to update the DCF and ERA and proposed that the DCF and ERA mechanisms be reactivated effective January 1, 2012.

57. To provide for a transition from 2009 GRA rates to once again setting rates based on annual long-term average hydro generation (as was done in 1996/97, the last time diesel was on the margin), YEC submitted that the diesel generation under its proposed forecast in Table 2.2 for the test years is set at about 59 to 66 percent of what would be required at annual long-term average hydro generation and hydro generation accordingly set at slightly above (approximately 101 to 102%).[28] YEC added that this approach takes advantage of current favorable water supply conditions, providing an opportunity to begin replenishing the DCF funds immediately, increasing rates, and reflecting the cost of diesel generation requirements with hydro generation levels set at long-term average levels.

58. Noting YEC repeated claims in another proceeding[29] before the Board that diesel was not on the margin, LE submitted that there was no justification for a transition as proposed by YEC. LE further submitted that using above long-term average hydro generation subsidizes rates with funds that should be going into the DCF. Considering the potential for a drought year wherein ratepayers will be paying large sums of money, LE suggested that "…we should be building up the DCF at every opportunity."[30] Accordingly, LE recommended that the Board order YEC to base its hydro and diesel

[27] Application, page 2-11.
[28] Application, page 2-13.
[29] YEC-YECL Rider F application.
[30] LE final argument, page 6, section 8.

energy generation requirements on 100 percent of long-term hydro generation for the test years.

59. YEC argued that LE's recommendation fails to recognize that current rate increases for the test period are capped at 6.4 and 6.5 percent, for 2012 and 2013 respectively.

Views of the Board

60. Based on its findings respecting the DCF and ERA in Section 3.6 below, the Board does not accept the proposed transition from 2009 rates. The Board directs YEC to base its hydro and diesel energy requirements on 100 percent of long-term average hydro generation for the forecast load in its compliance filing. In that compliance generation forecast, YEC is to confirm whether the effect of the Mayo A runner improvements have been included in the forecast. If not, YEC is to update its generation forecast accordingly.

3 Revenue requirement

3.1 Overview

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

- operating and maintenance expenses, including fuel costs, labour costs and costs for administering the utility;
- depreciation and amortization of assets and deferred costs included in rate base; and
- 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.

62. YEC stated that the forecast 2012 and 2013 revenue requirements primarily resulted from the proposed adjustments to diesel generation requirements and fuel prices, changes in fixed asset depreciation and amortization rates, planning cost study policy changes, changes to the proposed return on equity (including increases in mid-year rate base) as well as changes to labour and non-labour costs relative to the 2009 GRA approved forecast.[31]

[31] Application , pages 3-2 and 3-3.

Table 3. **Yukon Energy Revenue Requirement ($000)**[32]

				Forecast		Forecast	
	Actual 2009	**Actual 2010**	**FYF 2011**	**Existing 2012**	**Proposed 2012**	**Existing 2013**	**Proposed 2013**
Fuel and Purchased Power	658	1,183	2,746	642	2,203	1,866	3,113
Non-Fuel Operating and Maintenance	14,401	14,353	15,943	17,365	17,496	18,254	18,385
Depreciation and Amortization	6,555	6,656	6,901	9,988	7,813	13,177	10,012
Return on Rate Base	10,095	10,185	8,704	8,407	12,345	4,658	14,130
Revenue Requirement	31,709	32,377	34,294	36,402	39,857	37,956	45,641

3.2 Fuel and purchased power

63. Fuel and purchased power costs increase to $2.2 million and $3.1 million for 2012 and 2013 respectively. YEC submitted that the increased costs result from forecast higher loads, adjusted fuel prices and provisions for diesel being required based on annual long-term hydro generation. The following table illustrates fuel and purchased power costs for the period from 2009 to 2013.

Table 4. **Fuel and purchased power ($000)**

	2009 GRA Compliance	**Actual 2009**	**Actual 2010**	**FYF 2011**	**Existing 2012**	**Proposed 2012**	**Existing 2013**	**Proposed 2013**
Fuel	443	622	1,145	2,708	602	2,163	1,826	3,073
Purchased Power	54	26	38	38	40	40	40	40
TOTAL	497	658	1,183	2,746	642	2,203	1,866	3,113

Source: YEC Application, Table 3.2, page 3-4.

64. YEC submitted that diesel generation increased from the 2009 approved forecast amount of 0.945 GW.h to 4.2 GW.h in 2010, and to approximately 10.55 GW.h in 2011. YEC explained that the diesel generation in 2010 and 2011 reflected below average water conditions as well as non-activation of the DCF. Nonetheless, YEC forecast that diesel would be on the margin at annual long-term average hydro generation levels because of reduced surplus hydro generation caused by material increases in load.

65. Forecast fuel prices for the test period are $1.0513 per litre for Whitehorse, $1.0885 per litre for Faro, $1.168 per litre for Dawson, and $1.0966 per litre for Mayo, and are based on the most recent fuel prices paid by YEC. YEC average fuel efficiency forecasts of 3.77 kWh/litre in Whitehorse, 3.83 kWh/litre in Faro, 3.72 kWh/litre in

32 Application, page 3-2 – Table 3.1.

Dawson and 3.37 kWh/litre in Mayo were based on 2011 averages. YEC forecast total diesel generation of 7.5 and 10.7 GW.h, respectively for 2012 and 2013, which requires 2.0 million and 2.85 million litres of diesel fuel (including diesel fuel for mechanical maintenance purposes).

66. UCG noted that for 2009, the difference between the Board-approved price and the actual price for diesel fuel was 20 cents per litre, which equates to $97,000. UCG submitted 2009 rates have over-recovered on allowed diesel fuel costs and the Board should direct YEC to identify the over-recovery since 2009 and ensure that this over-recovery is added to the DCF. UCG further submitted that the Board direct YEC to report quarterly on any over- or under-recovery of allowed diesel fuel expense. Moreover, this difference should be tracked in a variance account that can be addressed at a later date.[33]

67. YEC replied that there was no merit to UCG's argument that YEC had over-recovered 2009 diesel fuel costs. Rider F captures all variations in fuel price per litre for each actual litre consumed, compared to the most recent GRA-approved fuel prices. Moreover, diesel fuel supply is procured by competitive public tender and prices are generally updated monthly for market price fluctuations. Respecting Rider F, YEC submitted that the rider is meant to only address the variations in fuel price per litre consumed; YEC remains at risk for changes in fuel volumes.[34]

Views of the Board

68. The Board has reviewed YEC's 2012 and 2013 fuel and price forecast and finds the forecast reasonable. However, the Board notes that directions in other areas of this decision, including the sales forecast section, may have an impact on YEC's fuel and purchase forecast. The Board directs YEC to review and explain the impacts of the changes in other sections on the fuel and purchased power forecast in YEC's compliance filing.

69. The Board believes it is important to address the UCG submission regarding Rider F. The Board considers that Rider F captures all variations in fuel price per litre for each actual litre consumed. The Board notes that diesel fuel supply is procured by competitive public tender and prices are generally updated monthly for market price fluctuations. The Board is not persuaded by the UCG submissions on Rider F that 2009 rates have over-recovered on allowed diesel fuel costs.

3.3 Non-fuel operating and maintenance expenses

70. YEC sought approval to include in revenue requirement, non-fuel operating and maintenance (O&M) expenses totalling $17.496 million and $18.385 million in 2012 and 2013 respectively. This represents a $4.3-million increase in 2012 over 2009 approved rates and a further $0.89-million increase in 2013 over the 2012 forecast.

[33] UCG final argument, paragraphs 192 to 194.
[34] YEC reply argument, section 3.2, pages 15 to 17.

Table 5. **Non-Fuel Operating, Maintenance Expenses ($000)**[35]

					Forecast		Forecast	
	2009 GRA Compliance	**Actual 2009**	**Actual 2010**	**FYF 2011**	**Existing 2012**	**Proposed 2012**	**Existing 2013**	**Proposed 2013**
Labour*	6,880	7,663	7,720	8,343	9,185	9,185	9,378	9,378
Production	798	963	1,236	1,478	1,449	1,449	1,437	1,437
Transmission	612	755	476	714	760	760	853	853
Distribution	178	114	111	184	201	201	226	226
General O&M	858	1,002	1,010	1,195	1,094	1,094	1,154	1,154
Administration	2,544	2,729	2,621	2,859	3,429	3,429	3,885	3,885
Insurance and Reserve for Injuries/ Damages	1,052	887	887	874	935	1,066	995	1,126
Property Taxes	256	288	291	297	312	312	326	326
Total O&M	13,178	14,401	14,353	15,943	17,365	17,496	18,254	18,385
*YEC noted during cross-examination that labour expenses should be $0.030 lower due to a larger allocation to YDC.								

3.3.1 Labour

71. YEC's 2012 forecast labour expenses increased by $2.305 million over 2009 approved rates. YEC's 2013 forecast labour expenses increased by an additional $0.193 million over its 2012 forecast. YEC noted that the labour expense increases are due to additional positions, as well as negotiated and stepped increases. The average annual increase in salaries per full-time employee (FTE) is 4.3 percent from 2009 to 2013. In response to an interrogatory, YEC noted that the Consumer Price Index (CPI) increases for Whitehorse were 0.4, 0.8, and 3.0 percent in 2009, 2010, and 2011 respectively.[36]

72. During the oral hearing, YEC revised their FTE allocation to Yukon Development Corporation (YDC) from 0.55 to 0.71. The forecast labour expenses for 2012 and 2013 were subsequently reduced by $0.03 million less than originally applied for in the Application.[37]

[35] Application, page 3-6, Table 3.3.
[36] YUB-YEC-1-13(e).
[37] Hearing Transcript, Volume 3, November 14, 2012, pages 539-540.

73. YEC's employee complement (FTE) for the period 2009 to 2013 is as follows:

Table 6. **Employee Complement History (FTEs)*[38]**

	2009 GRA Compliance	Actual 2009	Actual 2010	FYF 2011	GRA 2012	GRA 2013
President	2.50	4.5	5.50	5.50	4.50	4.50
Communications	1.00	1.00	1.00	1.00	1.00	1.00
Human Resources & Info. Mgmt.	7.00	5.00	6.00	7.10	6.25	6.25
Resource Planning and Environment	1.00	2.00	2.00	6.00	7.00	7.00
Finance, Cust. Acct'g & Purchasing	12.81	14.08	13.69	15.75	17.00	17.00
Operations	40.10	40.61	41.49	41.44	41.25	41.25
Engineering Services	12.00	12.00	15.44	14.00	13.00	13.00
Health, Safety & Environment	3.33	2.00	2.00	2.00	2.00	2.00
Total	79.74	81.19	87.12	92.79	92.00	92.00
* The employee complement numbers are net of allocation to YDC.						

74. LE argued that the increases to YEC staff were at a much higher rate than Whitehorse CPI, that 71 YEC employees will receive compensation packages in excess of $100,000, and that virtually all of the growth in labour costs originated from the office or upper levels of the corporation as opposed to the operational and maintenance end. LE did not believe that the increasing labour costs were supported but admitted that it had not analyzed the matter in detail and would defer to the recommendations of other parties.[39]

75. UCG stated that it was unrealistic to argue that higher wages need to be offered to attract qualified employees when concessions were the rule in other jurisdictions in this shrinking economy.[40] UCG submitted that the evidence contradicts YEC's claim that significant forecast growth in assets has required material increases in the size of YEC's labour and non-labour expenses. UCG suggested that at least nine of the positions identified in YEC's forecast do not relate to growth in assets. More specifically, UCG identified the following positions:[41]

- Network Administrator to Manager of IT
- IT Help Desk
- SQL/Sharepoint Administrator
- Manager, Energy Conservation
- Energy Conservation Administrator
- Backfill Controller
- Communications and Protection Control Technologist
- Permanent Part Time Plant Operator - Faro
- Term SCC Operator

76. Also, UCG submitted that no cost/benefit or business case analyses were provided for the additional positions.

38 Application, page 3-7, Table 3.4.
39 LE final argument, page 7, section 11
40 UCG final argument, page 41
41 UCG reply argument, page 5

77. UCG also expressed concern with the growing number of YEC staff positions that earn more than $100,000 per year (i.e. 77 percent of the proposed staffing level in 2012 and 2013).[42] UCG recommended that the Board disallow all proposed labour cost increases associated with salaries of YEC employees[43] and that all costs related to new staff positions in resource planning or energy conservation be split 50/50 between the shareholder and ratepayers.[44]

78. UCG also commented on YEC's retention of InterGroup for consulting services totalling $0.983 million during the 2009 to 2011 period. Further, UCG noted that for the amount spent on InterGroup, YEC could have provided incentive and training to have qualified staff based in the Yukon. UCG recommended YEC be directed to curb the duplication of costs incurred for these regulatory oversight services and that the budget for this type of consulting work be reduced by 50 percent for the 2012 and 2013 test years.[45]

79. In its argument, YEC responded that labour cost increases were extensively reviewed in interrogatories and in cross-examination. Further, YEC indicated that the labour cost increases were based on collective bargaining agreement rates and, as such, inflation is not a relevant indicator for the test years.[46]

80. YEC also stated that detailed justification for each additional position was provided in the Application. In the absence of the additional staff positions, YEC argued that they would have had to engage higher-cost consultants to deal with the utility's increased growth, increased assets, increased regulatory requirements, and need to perform detailed and multi-year planning.[47] YEC submitted that it is experiencing fairly significant potential retirements over the next few years and trying to make sure the right structure is in place for a smooth transition.[48]

81. In response to UCG's recommendation to reduce the costs spent on InterGroup by 50 percent, YEC reiterated that it does not have the specialized expertise and that it is difficult to hire or secure the breadth of expertise required to file applications and deal with the volume of information required. Further, YEC noted that it is currently taking steps to reduce its reliance on external consultants for regulatory purposes. More specifically, it has hired employees with transferable skills that may be able to take over some of the regulatory work previously sent to consultants in the future.[49]

Views of the Board

82. The Board acknowledges that labour cost increases were based on collective bargaining agreement rates. Without evidence to the contrary, the Board accepts that

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42 UCG reply argument, page 10.
43 UCG final argument, page 41, paragraph 228.
44 UCG final argument, page 44.41, paragraph 227.
45 UCG final argument, pages 39 - 40.
46 YEC reply argument, page 17.
47 YEC reply argument, pages 18 and 20.
48 YEC reply argument, page 18.
49 YEC reply argument, pages 20-21.

negotiations were conducted in good faith. Accordingly, the Board accepts the annual labour increases forecast by YEC for the 2012 and 2013 test years.

83. Further, the Board is of the view that interveners have not brought forward evidence in support of their position that the FTE additions are unreasonable. The Board notes that YEC has provided justification for these positions which has not been contradicted.

84. Based on evidence on the record, the Board is satisfied with YEC's forecast FTE complement with two provisos. The first, with the exception of positions related to demand-side management (DSM) and the ECD which are discussed below, the Board approves YEC's FTE complement for the 2012 and 2013 test years. The second is that YEC is to demonstrate in its next GRA that the complement levels approved in this GRA will have effectively reduced the costs or use of outside consultants.

85. The Board directs YEC to remove all labour costs attributable to DSM and the ECD from the revenue requirement for the 2012 and 2013 test years in its compliance filing. The Board directs YEC to track and defer these costs until the Board approves a final DSM policy for YEC, as discussed in Section 5.3.

86. The Board approves a complement of 90 FTEs for YEC's revenue requirement for the 2012 and 2013 test years.

3.3.2 Production

87. YEC's total production costs in 2012 are forecast to increase by $1.48 million over 2009 approved costs, and by an additional $0.042 million in 2013 over the 2012 forecast. YEC submitted that approximately 56 percent of the forecast increase in 2012 over 2009 approved costs is due to higher labour costs, with the balance of the increase due to ongoing increases on materials, supplies and services as well as increases due to the new hydro units in service.

Table 7. **Production Costs ($000)**[50]

	2009 GRA Compliance	Actual 2009	Actual 2010	FYF 2011	GRA 2012	GRA 2013
Labour	2,179	2,796	2,943	5.50	4.50	4.50
Diesel	194	333	297	615	425	425
Hydro	560	602	895	852	938	938
Wind	8	6	6	5	27	18
Oper. Sprvsn	36	22	38	6	59	59
Total Production	2,977	3,759	4,179	4,472	4,452	4,452

88. In argument, LE recommended that the Board approve the requested wind production costs of $0.027 million and $0.018 million in 2012 and 2013 respectively. LE also recommended the Board order YEC to increase the time and attention spent on the

50 Application, page 3-7, Table 3.5.

Haeckel Hill wind facility to improve production to at least 0.80 GW.h per year in 2013 and to budget up to $100,000 in 2013 to achieve this.[51]

89. YCS commented on the performance of the Haeckel Hill Wind facility and claimed that the poor performance was a "…result of purposeful neglect of wind facilities, and is another tactic – whether conscious or otherwise – employed by YEC to sway public opinion to match its own – that wind is not viable or feasible in the Yukon." YCS recommended that the Board direct YEC to give the wind facilities the same level of care and attention afforded to the other generation facilities.[52]

90. In its reply argument, YEC disagreed with the interveners that it was neglecting its wind generation facility at Haeckel Hill to "sway public opinion" against wind generation. YEC noted the work that it has already done related to wind generation.[53]

91. YEC submitted that LE has not provided any evidence that Haeckel Hill has been ignored or that the performance at Haeckel Hill has resulted in more winter diesel generation than necessary. YEC also argued that LE has not provided any evidence to support the proposed costs, generation benefits, revenue savings, or even considered the other required maintenance or operations work that may need to be deferred in favour of LE's recommendation.

Views of the Board

92. The Board considers that interveners have not provided convincing evidence that increased investments in wind generation assets beyond the levels requested in the Application are in the best interest of ratepayers. Accordingly, the Board does not accept the intervener recommendations. Further, the Board accepts YEC's explanations of the reasons for its level of investment in its wind generation assets.

93. No evidence was put forward to dispute the other requested production costs.

94. Accordingly, the Board accepts YEC's applied-for production increases that form a part of YEC's Non-Fuel Operating, Maintenance and Administration Expense budget for the test years, as reflected in Table 7 above.

3.3.3 Transmission

95. YEC's total transmission costs in 2012 are forecast to increase by $0.096 million over 2009 approved costs, and by an additional $0.103 million in 2013 over the 2012 forecast. YEC submitted that the increases are due to the completion of CSTP Stage Two and connection of the MD and WAF grids, as well as brushing activities. Overall brushing costs increase by $0.128 million in 2012 forecast over 2009 approved costs with an additional $0.134 million increase in 2013 forecast over the 2012 forecast.

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[51] LE reply argument, page 6, section 9.
[52] YCS final argument, page 6
[53] YEC reply argument, page 22.

Table 8. **Transmission Costs ($000)**[54]

	2009 GRA Compliance	Actual 2009	Actual 2010	FYF 2011	GRA 2012	GRA 2013
Labour	482	453	319	396	431	440
Brushing	377	387	268	434	505	639
Other Non-Labour	235	369	208	280	255	214
Total Transmission	1,094	1,208	795	1,110	1,190	1,293

96. YEC stated in the Application that in compliance with Board Order 2009-8,[55] YEC undertook a brushing survey of North American utilities on industry best practices and commissioned a quantitative audit and assessment of their vegetation control practices with the objective of developing a cyclical brushing strategy.[56] The survey which was conducted by the Centre for Energy Advancement through Technological Innovation (CEATI) International cost $0.025 million. The audit and assessment work done by Environmental Consultants, Inc. (ECI) cost $0.105 million with an additional $0.027 million in helicopter fees for aerial surveys.[57] The two studies were attached to the Application as Appendix 12.1 and Appendix 12.2.

97. YEC submitted that the estimate for the 2012 brushing costs was based on testing the recommendations in the ECI study[58] and that the results of this work would form part of the brushing policy to be developed in 2013.[59]

98. In response to an IR, YEC provided its annual transmission costs on a per-kilometre-of-transmission-line basis.

Table 9. **Transmission Costs per km of Transmission Line ($000)**[60]

	2009 GRA Compliance	Actual 2009	Actual 2010	FYF 2011	GRA 2012	GRA 2013
Labour	0.57	0.53	0.34	0.42	0.46	0.47
Brushing	0.44	0.46	0.29	0.46	0.54	0.68
Other Non-Labour	0.28	0.43	0.22	0.30	0.27	0.23
Total Transmission	1.29	1.42	0.85	1.19	1.27	1.38

99. CW noted that during cross-examination, YEC explained that the transmission brushing costs in recent years have increased due to excess precipitation creating more undergrowth. CW acknowledged that YEC's overall transmission brushing costs should

54 Application, page 3-8, Table 3.6.
55 The Board therefore directs YEC to undertake a study into brushing activities of similar utilities and report its findings to the Board at the time of its next GRA. Further, the Board directs YEC in its report to include a written brushing policy that describes comprehensively YEC's approach and explains the manner in which the budget for any year is derived.
56 Application, page 3-8 to 3-9.
57 YUB-YEC-1-17(c).
58 Application, page 3-9.
59 YUB-YEC-1-17(b).
60 CW-YEC-1-18(b), Table 3.6.

increase due to completion of the CSTP. However, CW stated that on a per-kilometre basis, it appears that YEC's unit brushing costs are related more to rate applications than precipitation. CW recommended the Board reduce YEC's forecast brushing costs to the average per-unit brushing costs between 2010 and 2011 of $375/km for the test years.[61]

100. LE commended YEC on the progress it has made on its vegetation management practices and recommended the Board approve YEC's proposed vegetation plans and budgets.[62]

101. UCG noted that while YEC provided copies of the brushing studies undertaken and completed in December 2010 and January 2012, YEC did not intend to develop a formal brushing policy until 2013, which means that there is nothing upon which the Board and interested parties could base the escalating brushing costs for 2012 and 2013. UCG recommended that the 2012 and 2013 budgets for brushing should not be any more than the amount allowed for 2009. This would reduce the revenue requirements for 2012 and 2013 by $175,000 and $329,000 respectively.

102. Further, given the fact that YEC has not developed a policy based on the consultant studies related to brushing, UCG submitted that the $173,227 cost of these studies should not be allowed to be recovered until after the policy has been reviewed by the Board and implemented.[63]

103. YEC stated that it has provided full explanations and support in the Application, IRs, and cross-examination for its forecast transmission and distribution brushing costs. Further, YEC argued that the interveners' arguments as to why the increase in the test years is not justified fail to recognize the extensive brushing study undertaken by ECI which YEC argued forms the basis for its 2012 transmission brushing estimate.

104. Further, YEC submitted that brushing costs could not be maintained at the same levels as in 2010 for a number of reasons which included:

- The 2010 brushing program was affected by a significantly increased fire season in comparison to 2011. Based on the daily fire danger rating, YEC policy is to suspend brushing to mitigate potentially starting fires using mechanical equipment.
- Maintaining brushing expenses at a level of spending as low as 2010 would create problems in the future.
- The cyclic brushing plan and Integrated Vegetation Management Plans have identified a need for a substantial increase of funds to the transmission brushing program in order to deal with a backlog of brushing that is urgently required.
- In 2012, management intends to advance herbicide application, which was one of the key recommendations in the brushing study.

61 CW final argument, page 7.
62 LE final argument, page 7.
63 UCG final argument, page 39, paragraph 218.

105. In response to UCG's recommendation that the recovery of the cost of the brushing studies should not be allowed until a brushing policy had been developed, reviewed, and approved by the Board, YEC noted that it has fully explained in the Application why a brushing policy is not yet available. Further, YEC submitted that the results of the brushing study undertaken by ECI are currently in the process of being tested and implemented and it had provided full support for the test-year spending. As such, the brushing expense for the test years should be approved as proposed and the costs for the brushing studies undertaken by YEC to comply with the Board direction provided in Order 2009-8 should be approved and included in rate base as proposed in the Application.[64]

Views of the Board

106. With respect to vegetation management test-year costs, the Board took note of YEC's submission that:

> Pursuant to direction provided in Order 2009-8, Yukon Energy commissioned a quantitative audit and assessment of its vegetation control practices with the objective of developing a cyclical brushing strategy which met YEC's goals of cost effectiveness, safety, and security of energy transmission.
>
> - The study recommended an annual brushing plan which would allow YEC to meet these goals.
> - The study has also identified several risk areas for lines that will need immediate attention in 2012.
> - The transmission brushing estimate for 2012 is based on working to this plan and to these cost estimates.[65]

107. The Board accepts that test-year brushing costs are related to testing the ECI brushing study results. Further, the Board notes that YEC intends to complete a study to select and test an appropriate herbicide, which "…will form part of the brushing policy to be developed in 2013."[66] Moreover, the cyclic brushing and the integrated vegetation management plans have identified a need for a substantial increase of funds to the transmission brushing program in order to deal with a backlog of brushing that is urgently required.[67] Considering the above, the Board considers the test-year costs to be reasonable.

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

[64] YEC reply argument, page 24 to 25
[65] YEC reply argument page 24.
[66] YUB-YEC-1-17 (b).
[67] YEC reply argument, page 24.

test the reasonableness of the proposed policy and the costs held in the vegetation management deferral account.

3.3.4 Distribution

110. YEC's total distribution costs in 2012 are forecast to increase by $0.081 million over 2009 approved costs, and by an additional $0.039 million in 2013 over the 2012 forecast.

Table 10. **Distribution Costs ($000)**[68]

	2009 GRA Compliance	Actual 2009	Actual 2010	FYF 2011	GRA 2012	GRA 2013
Labour	521	546	477	473	579	592
Brushing	46	17	16	68	93	113
Other Non-Labour	132	97	96	116	108	113
Total Transmission	699	660	588	657	780	819

111. In response to an IR, YEC stated that brushing and other non-labour expenses declined relative to the 2009 forecast due to the use of internal labour for brushing, as opposed to contractors, and that both meter and street light maintenance were lower than planned. YEC also provided its annual distribution costs on a per-kilometer-of-distribution-line basis.[69]

Table 11. **Distribution Costs per km of Distribution Line ($000)**[70]

	2009 GRA Compliance	Actual 2009	Actual 2010	FYF 2011	GRA 2012	GRA 2013
Labour	1.28	1.34	1.17	1.16	1.43	1.46
Brushing	0.11	0.04	0.04	0.17	0.23	0.28
Other Non-Labour	0.32	0.24	0.24	0.29	0.27	0.28
Total Transmission	1.72	1.62	1.45	1.61	1.92	2.01

112. CW pointed out that YEC submitted: "In 2011, an external contractor was hired to brush about 20 km in Dawson, as well as a number of critical sites in Mayo. For 2012 and 2013 YEC intends to continue this approach and would expect to achieve similar results."[71] CW highlighted the following YEC response during cross-examination:

> **YEC PANEL CROSS-EXAMINED BY MR. MARRIOTT VOLUME 1**
>
> **Q. If we can expect similar results from the contractor in 2012 and 2013 as we experienced in 2011, how do we go from a 2011 forecast of $68,000 to the $93,000 in 2012 and $113,000 in 2013?**

68 Application, page 3-9, Table 3.7.
69 CW-YEC-1-19.
70 CW-YEC-1-19(b), Table 1.
71 Exhibit B5, YECL-YEC, 1-28(a)

> A. MR. MOLLARD: It's the same contractor, it's the same approach. It would be just a different volume of brushing that we would be doing.
>
> A. MR. MORRISON: Brushing is not a black-and-white concept. Brushing from one year to the next is very different based on the trees in the area, how much they've grown, the cycle of when we've been back there last. One area of one community can be much different than another area of that one community. So there is no-- there's no formulaic approach that it costs this much, and it's this much per kilometre every place you go all the time. It's just not that precise. [72]

113. CW acknowledged that YEC has contracted out its distribution brushing function and that distribution brushing costs may not be comparable in 2011 to years when distribution brushing was done internally. However, CW submitted that it appears that the cycle of brushing seemed to include difficult communities during rate applications. CW recommended that the Board reduce YEC's forecast distribution brushing costs to $0.068 million since YEC expects similar results in 2012 and 2013 as in 2011.[73]

114. For both transmission and distribution brushing costs, UCG argued that without a brushing policy, the Board could not approve an increase in brushing costs or the costs related to the brushing studies. UCG recommended that the 2012 and 2013 budgets for brushing should not be any more than the amount allowed for 2009.[74]

115. YEC responded to interveners' arguments regarding transmission and distribution brushing costs concurrently. To reiterate, YEC argued that they have fully explained in the Application why a brushing policy is not available and that brushing costs cannot be maintained at 2010 levels for a number of reasons.[75]

Views of the Board

116. In making its determination, the Board considered that YEC contracted out its distribution brushing function in 2011 and that, going forward, distribution brushing expenses would be higher. However, as noted by CW, if YEC expects the same results in the test period as in 2011, the costs should be the same.

117. As was done respecting transmission vegetation management costs, the Board accepts YEC's proposed distribution brushing costs for the test years. However, for the period beyond the test years (future years) the Board directs YEC to create a distribution vegetation management deferral account. In future years, distribution vegetation management related costs greater than 2011 actual brushing costs are to held in the newly distribution created 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.

72 Hearing Transcript, Volume 1, November 12, 2012, page 70, line 15 to page 71, line 5.
73 CW final argument, page 8.
74 UCG final argument, page 39, paragraph 217.
75 YEC reply argument, page 24.

3.3.5 General operation and maintenance

119. YEC's total general O&M costs in 2012 are forecast to increase by $0.384 million over 2009 approved costs, and by an additional $0.066 million in 2013 over the 2012 forecast. YEC submitted that the total forecast cost increases relate largely to escalations in non-labour expenses. More specifically, YEC stated that the forecast costs for the maintenance of company owned property, transportation, and SCADA communication would increase by $0.197 million, $0.033 million, and $0.006 million in 2012 over 2009 approved costs.

Table 12. **General Operating and Maintenance ($000)**[76]

	2009 GRA Compliance	Actual 2009	Actual 2010	FYF 2011	GRA 2012	GRA 2013
Labour	94	143	184	141	245	250
Transportation	394	401	419	449	427	451
Maintenance of Company Owned Properties	384	471	489	650	581	611
SCADA Communication	80	130	102	96	86	93
Total General O&M	952	1,145	1,194	1,336	1,339	1,405

Views of the Board

120. No evidence was put forward to dispute YEC's general O&M forecast. The Board has reviewed these costs and considers them reasonable based on the evidence provided by YEC. Accordingly, the Board accepts YEC's applied-for general O&M forecasts that form a part of YEC's Non-Fuel Operating, Maintenance and Administration Expense budget for the test years.

3.3.6 Administration

121. YEC's total administration costs in 2012 are forecast to increase by $2.209 million over 2009 approved costs, and by an additional $0.566 million in 2013 over the 2012 forecast.

[76] Application, page 3-10, Table 3.8.

Table 13. **Administration ($000)**[77]

	2009 GRA Compliance	Actual 2009	Actual 2010	FYF 2011	GRA 2012	GRA 2013
Labour	3,605	3,725	3,797	4,338	4,927	5,038
Resource Planning	17	18	24	128	26	26
Communications	105	98	119	98	306	295
Customer Accounting	206	182	185	194	190	191
Environmental Mgmt	52	50	82	152	338	569
General	734	886	611	804	910	1,099
Information Systems	425	595	548	388	569	607
Fish Hatchery	136	159	176	140	182	187
Fish Ladder[1]	26					
Safety	162	187	201	177	177	189
Training	211	205	150	184	260	260
Recruitment	169	138	192	83	120	120
Board of Directors	148	113	100	289	180	168
Union	26	9	72	25	23	23
Regulatory Affairs	57	27	77	156	34	34
Material Management	43	-6	64	18	33	35
Contracting	11	60	17	8	15	16
Professional Development	15	9	2	15	17	17
DSM Administration					49	49
Total Administration	6,148	6,453	6,418	7,197	8,357	8,923
[1]Fish ladder cost for 2009-2013 included in Production Function.						

122. CW, LE, and UCG all commented on different components of YEC's Administration expenses. Each party's arguments and Board findings on the disputed components are discussed below. Administration accounts which are not discussed in this decision are approved as applied-for by the Board for the 2012 and 2013 test years because the Board reviewed the amounts forecast in this section and considers the forecasts to be reasonable.

3.3.6.1 DSM administration

123. CW submitted that DSM administration appears to cover costs that should be incorporated into other accounts. CW stated that YEC proposed significant increases in the Communications, Training, and General accounts, all of which appear to describe the types of expenses set out in Section 2.2 of the DSM policy. CW further submitted

77 Application, page 3-11, Table 3.9.

that the breakdown of 2012 DSM administration expenses incurred to date confirms that expenses under the DSM administration account already have corporate accounts or are not covered by the DSM policy (e.g. rent). CW argued that including DSM administration expenses in corporate accounts ensures that DSM thinking is incorporated into all activities undertaken by YEC. Further, CW stated that it is concerned that DSM administration expenses have no definable benefits, unlike projects that are amortized.

124. CW recommended that the Board direct that all DSM administration expenses be excluded from 2012 and 2013 revenue requirement and the DSM policy be modified by including the underlined wording in Section 2.2:

> 2.2 The following DSM-related costs shall be expensed <u>to the appropriate corporate account</u> as incurred[78]

125. In reply argument, LE argued that DSM is a vitally important initiative and that the disallowance of DSM costs would be a strong negative signal to the utilities and would further discourage much needed progress on this front. Further, LE argued that it is very important for all costs attributable to DSM to be tracked so that the costs and benefits of DSM will be clearly apparent.

126. YEC strongly disagreed with CW's recommendation to eliminate the DSM Administration expense in revenue requirement. YEC stated that none of the costs included under DSM administration are currently accounted for under the Communications, Training or General expense budgets and if the DSM administration account were to be eliminated, amounts specific to DSM would have to be added to each of these separate accounts. YEC added that they are treating the DSM administration expense as a separate item in order to show how these costs are being accounted for according to the policy and that its approach fosters transparency.

Views of the Board

127. The Board has considered CW's argument; however, the Board does not agree with CW's approach and recommendation. The Board discusses YEC's DSM deferred costs in the deferred costs section later in this decision.

3.3.6.2 Communication

128. YEC's communication costs are forecast to increase from $0.105 million to $0.306 and $0.295 million in 2012 and 2013 respectively over the 2009 approved communication budget. YEC stated that the increased costs relate to implementation of an ongoing public information campaign which accounts for approximately $0.200 million of the total budget and $0.05 million for upgrading YEC's website.[79]

129. In response to an IR, YEC submitted that they had included the information regarding the website upgrade in error since it was never approved.[80]

[78] CW final argument, page 8.
[79] Application, page 3-11 to page 3-12.
[80] YUB-YEC-2-13(d).

130. LE supported YEC's communication initiatives that included the improved website, the social media initiative, and the "Ask Janet" feature. However, LE was of the opinion that there has been far more YEC newspaper advertisements than necessary to make people aware of YEC. LE also submitted that it was concerned with what appears to be a fair bit of "spin doctoring" going on which, in LE's view, is inappropriate for a public utility. Further, LE believed that an increase of about $200,000 over previous annual budgets of about $100,000 at a time when rates are increasing is inappropriate. LE recommended that the Board order YEC to limit communications spending to $0.175 million in each of 2012 and 2013.

131. In response to LE, YEC noted that it completely rejected LE's assertion that YEC's evidence was in any way misleading or "spin doctoring." YEC argued that LE had not provided any substantive detail or basis regarding what the appropriate level of advertising would be or how this has been exceeded. YEC further argued that LE has not provided any evidence to support the $0.175 million budget recommended for each of the test years. YEC submitted that the Board should not adopt LE's recommendation.[81]

132. UCG submitted in reply argument that YEC had stated in support of its communication budget that "Public input helps Yukon Energy make decisions regarding energy investments and strategic planning and also provides valuable input towards project planning."[82] However, UCG submitted that YEC confirmed during its testimony that it did not conduct stakeholder consultations with interveners, YECL, First Nations, municipalities, etc. on the contents of the GRA.[83]

133. UCG recommended that if a portion of the communication budget in 2012 had been earmarked to gather public input on the strategies and investment decisions proposed in the Application, a portion of that budget should be denied.

Views of the Board

134. The Board agrees with LE that a $0.201-million increase (i.e. a 191-percent increase over the 2009 approved forecast) in discretionary spending when rates are increasing is not acceptable. Further, the Board finds that YEC has not provided adequate evidence to satisfy the Board that ratepayers would exchange more communication for higher utility rates. The Board directs YEC in its compliance filing to reduce the communication forecasts to $0.105 million for each of the 2012 and 2013 test years.

3.3.6.3 Board of Directors

135. In the Application, YEC forecast Board of Directors costs to increase to $0.180 million and $0.168 million in 2012 and 2013 respectively. This represents a $0.032-million and $0.020-million increase over the 2009 approved forecast.

81 YEC reply argument, page 26.
82 YEC final argument, page 29.
83 UCG reply argument, page 11, paragraph 50.

136. In response to an IR, YEC provided the total honoraria paid to YEC Board Members from 2009 to forecast 2013.

Table 14. **Total Honoraria Paid to YEC Board Members for 2009 – Forecast 2012-13 ($)**[84]

Position	2009	2010	2011	2012	2013
Director 1	1,100	3,400	6,600	6,500	6,500
Director 2	1,100	4,400	7,100	6,500	6,500
Director 3	4,000	200	7,700	6,500	6,500
Director 4	7,500	4,200	3,300	6,500	6,500
Director 5	8,300	5,200	8,800	6,500	6,500
Director 6	8,350	7,350	8,300	6,500	6,500
Director 7	15,200	9,500	10,600	11,000	11,000
Chair	17,900	27,100	54,900	54,000	54,000
Total	65,459	63,360	109,311	104,000	104,000

137. UCG stated in final argument that according to the respective websites of YEC and YDC, the two organizations share a member on their respective Board of Directors. Given the overlap, UCG recommended the Board carefully consider the payments being made by ratepayers to members of YEC's Board of Directors. More specifically, UCG recommended that the Board remove the direct and indirect costs related to this board member from the 2012 and 2013 revenue requirement to avoid ratepayers paying for inherent bias.

138. Further, UCG recommended that $0.030 million in fees related to the YEC Chair should be removed from the 2012 and 2013 revenue requirement for work that appears to be more politically based than utility based to ensure that ratepayers only pay for services rendered with respect to utility services.[85]

139. YEC argued that UCG had not provided any explanation about what it meant by "inherent bias" or how it relates to YEC's revenue requirement. YEC further submitted that there is no basis to remove the $0.030 in fees related to the YEC Chair from the revenue requirement. YEC reiterated that the amount of work done by the Chair has increased significantly due to the undertaking of several large projects which required more board involvement and a new government which required more briefings.

Views of the Board

140. The Board accepts that the forecast costs for 2012 and 2013 are reasonable in that the increase in honoraria is a small increase in relation to the increase in the work undertaken by the board members due to several large projects that required more board involvement. UCG has not explained its allegation of inherent bias in relation to YEC and YDC having board members in common or provided any satisfactory evidence in support of its allegation. The Board approves YEC's applied-for forecast Board of Directors costs for the test years.

84 UCG-YEC-1-26(b), Table 2.

85 UCG final argument, page 41, paragraph 234.

3.3.7 Insurance and reserve for injuries and damages

141. YEC's total insurance and reserve for injuries and damages (RFID) forecast costs in 2012 are to decrease by $0.117 million over 2009 approved costs, and then increase by $0.060 million in 2013 over the 2012 forecast costs.

142. The RFID is an account maintained as approved by the Board, to address uninsured and uninsurable losses as well as the deductible portion of insured losses. The RFID allows:

a. for a balance to be struck between purchasing additional insurance vs. using a self-insurance type approach via the RFID; and
b. the costs of unforeseen events to be smoothed out over a number of years to avoid rate instability for ratepayers.

143. YEC indicated that the RFID has grown to negative $0.578 million by end of year 2011. YEC proposed and requested approval for a three-part solution to avoid similar negative balance issues in the future which, if approved, would increase YEC's total cost for insurance and RFID by $0.014 million in 2012 over 2009 approved costs and by an additional $0.060 million in 2013 over the 2012 forecast. More specifically, YEC proposed[86]:

i. increasing RFID appropriations to $0.195 million from the currently approved $0.100 million;
ii. transferring the $0.398 million of one-time funds from the Faro Mine Dewatering Deferral Revenues against the RFID balance; and
iii. amortizing the negative balance of $0.180 million over a five year period.

144. YEC noted that in compliance with Board Order 2009-8, it had completed the risk-management studies and developed a written policy outlining the criteria for charging items to the RFID:

a. The proposed Finance Policy FA-014 (RFID policy) is provided as Appendix 3.1 to Tab 3; and
b. The directed studies are provided in Tab 12 Appendix 12.3 and Appendix 12.4.

145. In response to CW-YEC-1-43(c), YEC stated that "based on the actuarial methods explained in the report, the adjustment to the RFID threshold to $10,000 would reduce the annual charge to approximately $190,000 or about $5,000 less than the recommendation in the report." Based on this, YEC proposed in reply argument to reduce the annual appropriation to $0.190 million and to address this in the compliance filing.[87]

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[86] Application, page 3-18 to 3-19.
[87] YEC reply argument, page 29.

Table 15. **Insurance and Reserve for Injuries & Damages ($000)**[88]

	2009 GRA Compliance	Actual 2009	Actual 2010	FYF 2011	GRA 2012		GRA 2013	
					Existing	Proposed	Existing	Proposed
Insurance	952	787	787	774	835	835	895	895
Reserve Appropriation (RFID)	100	100	100	100	100	231	100	231
Total	1052	887	887	874	935	1066	995	1126

146. CW supported YEC's proposal to transfer funds to RFID from the Faro Dewatering Fund and to close the account, to amortize the remaining deficit in RFID over five years, and to increase annual appropriations to the fund. However, CW argued against the actuary's recommendation that the annual appropriation, net of any deficit amortization, be increased to $195,000.

147. CW stated that based on the RFID policy,[89] the value of any loss above $10,000 would be charged to the reserve. CW argued that self-insurance should be treated consistently with commercial insurance and should bear an effective deductible. CW submitted that the RFID policy should be amended to charge the first $10,000 of the qualifying loss to the department incurring the loss. CW argued that this would induce employees and managers to employ practices that will reduce claims.

148. Further, CW recommended that the annual RFID appropriation be reduced by $0.030 million to reflect the proposed deductible. CW provided a table illustrating the history of RFID claims to support their recommendation.[90]

149. In argument, LE submitted that it supports YEC's proposal to transfer funds remaining in the Faro Mine Dewatering Account into the RFID; however, LE did not agree with amortizing the $0.180 million negative balance in the RFID over five years. Instead, LE recommended increasing the annual appropriations into the RFID to $0.210 million. LE argued that this alternative would reduce the short-term negative rate impact on ratepayers (compared to amortization) and hopefully make the annual appropriation more realistic.[91]

150. UCG submitted that YEC had not provided enough information on the record to justify any of the expenses that have been charged to the RFID. More specifically, UCG submitted that they were uncertain as to why charges related to what appear to be operation expenses, capital projects and/or warranty work were charged to the RFID at all. UCG argued that there was no need to transfer funds from the Faro Dewatering Account to amortize costs that have not been adequately explained or justified.

151. UCG added that standard business practice would suggest that the $10,000 minimum threshold, below which a loss is considered operational risk, proposed by YEC is too low. UCG submitted that the average of the 13 charges to the RFID over the last three years was $64,000; therefore, the minimum threshold should be at least $50,000.

88 Application, page 3-17, Table 3.10.
89 Application, Appendix 3.1, page 3.1-1.
90 CW final argument, pages 14 to16.
91 LE final argument, pages 7 to 8.

UCG also submitted that if the Board sets a new threshold that is higher than $10,000, then all charges to the RFID below this new threshold amount should be eliminated from the RFID.

152. UCG added that the proposed RFID policy should be changed as follows:

i. Paragraph 4.1 should be changed from "Uninsured and uninsurable losses and associated costs will be charged to the RFID if they meet the following criteria:" to "Uninsured and uninsurable losses and associated costs will be charged to the RFID if they meet each of the following criteria:"

ii. The criteria for charging to the RFID should include "insurance policy deductible exceeds total value of loss;" and

iii. The policy should stipulate that where unanticipated insurance proceeds related to any items that have been included in the RFID will be applied against the RFID.

153. UCG also submitted that the Faro Dewatering Account has been used to the benefit of ratepayers in that it has provided YEC with a source of no-cost capital, thereby reducing current revenue requirements through a lower rate base than otherwise would occur. UCG recommended that the Board should direct YEC to provide a thorough reconciliation of the actual impact of the proposed drawdown of the Faro Dewatering Account.[92]

154. In response to UCG, CW stated that it did not oppose a higher threshold to the RFID, but the RFID policy would still require changes to ensure that the portion of all losses charged to the RFID that are below any new threshold would be to YEC and not to the customer. CW noted that UCG's RFID threshold proposal would also require alteration to the RFID appropriation to reflect the higher appropriation.[93]

155. YEC argued that both CW and LE did not accept the results of the actuarial evaluation by AON but provided no supporting factors or evidence to contradict the conclusions outlined in the AON study. Therefore, YEC argued that the recommendation by CW to reduce the annual appropriations by $0.030 million and the recommendation by LE to deny the amortization of the remaining $0.180-million deficit but instead increase the annual appropriation to $0.210 million should be ignored.

156. YEC stated that there is no precedent in support of YEC absorbing the first $10,000 of all losses charged to the RFID. YEC noted that if this concept were to be accepted as recommended, an offset to the revenue requirement in the test years would need to be approved as the line departments would need to absorb on average $30,000 of losses.

157. Similarly, YEC noted that increasing the minimum threshold to $50,000 as UCG recommended would require an increase in non-labour O&M in the test years. YEC also

[92] UCG final argument, page 36 – page 38.
[93] CW reply argument, page 7.

noted that there is no basis to suggest that the expenses charged to the RFID were not prudently incurred and provided the following response to UCG's argument that there was insufficient information on the record to justify the items charged to the RFID:[94]

a. This hearing has involved an extensive Application that included detailed actuarial studies filed in support of the RFID proposals as appendices to the Application.[95]

b. The hearing process included two rounds of interrogatories where interveners such as UCG had the full opportunity to ask questions regarding the Application, including follow up questions related to the first round of interrogatories.

c. Further, UCG had an opportunity to test YEC's revenue requirement at the oral hearing. UCG does not provide any factual basis to support the denial of these costs (beyond questions outlining rhetorical questions in argument).

d. Full descriptions to support items charged to the reserve was provided in YECL-YEC-1-51(c). This response fully explains the nature of the loss and why each individual item meets the criteria for inclusion in the reserve.

e. Based on a review of past charges to the account YEC wrote off amounts in 2011 (see Note on Table 1 in YECL-YEC-1-51(b)). The toolkit was written off as part of the 2011 adjustment to accounts.

158. YEC also argued that there was no basis for the proposed wording changes recommended by UCG. YEC noted that they have already indicated in response to interrogatories from the Board,[96] that an item must meet the listed criteria in the RFID policy before being charged to the RFID.

159. Further, YEC argued that to include the criterion that "insurance policy deductible exceeds total value of loss" is unnecessarily restrictive. YEC stated that YEC, with the assistance from insurance specialists, makes assessment of the appropriate treatment of each loss and that interested parties have an opportunity to test these determinations at each GRA before the costs are included in rate base. YEC argued that to force certain losses to be absorbed by YEC when it may make sense to charge these to the reserve to protect against possible premium increases is not reasonable or fair to the utility or its ratepayers.

160. YEC added that it was not aware of any circumstances where unanticipated insurance proceeds would arise.

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94 YEC reply argument, page 30.

95 Application, Appendix 12.3 and Appendix 12.5.

96 YUB-YEC-1-28(b).

Views of the Board

161. The Board notes CW's recommendation that the first $0.01 million of any qualifying loss should be charged to the department causing the loss. The Board understands the appeal of making self-insurance consistent with commercial insurance; however, the Board finds this practice impractical for the following reasons:

a. With commercial insurance, an entity has the option of increasing its deductible in exchange for more attractive premiums or, vice versa, decreasing its deductible in exchange for higher premiums. Theoretically, an entity should be able to enter into an arrangement where no deductible is paid but much higher insurance premiums are required. Under a self-insurance model, the utility does not get this consideration. Whether there is no deductible, a $0.030-million deductible, or a $0.050-million deductible, there is no premium that can be reduced to offset this additional burden. Therefore, it would be unfair to impose this additional cost on the utility.

b. It is a longstanding regulatory principle that any costs incurred prudently in the operation of utility services are recoverable. If a deductible were put in place, an offset would be required in the revenue requirement for the test years.

162. The Board, therefore, does not accept CW's recommendation to implement a deductible of $0.010 million on charges to the RFID. Further, the RFID appropriation reduction of $0.030 million rests upon the assumption that the Board accepts the recommendation of CW to implement the deductible; therefore, the Board rejects CW's recommendation to reduce the applied-for RFID appropriation.

163. The Board has considered LE's recommendation but finds that without further evidence to support the proposed $0.210 RFID appropriation or how this level of funding is more acceptable than the amount proposed by YEC, the Board cannot fully assess LE's recommendation. Therefore, LE's recommendation is rejected.

164. The Board also considered UCG's argument that the minimum threshold for charging costs to the RFID should be changed from $0.010 million to at least $0.050 million because the average charge to the RFID over the past three years was $0.064 million. The Board is of the view that UCG has not demonstrated the significance of the $0.064-million statistic or why the minimum threshold should be set at this number. In the Board's view, this statistic only demonstrates that roughly half of the charges to the RFID are below and half are above $0.064 million. The Board, therefore, rejects this recommendation.

165. The Board rejects UCG's recommendation that it deny the transfer of funds from the Faro Dewatering Account and amortize the $0.180-million deficit from the RFID due to a lack of information on the record. The Board considers that the record contains sufficient information for it to make a decision on this topic. The Board has reviewed the RFID policy put forward by YEC as well as the changes proposed by UCG. The Board is of the view that the proposed changes would make the criteria for charging costs to the RFID too restrictive, which may hinder the effectiveness of self-insurance altogether.

Further, the Board notes that interveners will have the opportunity to test any future changes in the RFID in future GRAs.

166. The Board understands that the RFID helps mitigate rate instability. In light of the growing deficit in the account, the Board recognizes that the RFID in its current state is not working. Further, any plans to reform the RFID must address the current deficit in the account and balance the appropriations from customers with the charges to the RFID over time, which means either appropriations must increase or the criteria for charging items to the RFID must be tightened. In the Board's view, the purpose of an RFID is to create flexibility so the utility can choose the lower cost option between making a claim and writing off losses. To make the RFID criteria too restrictive would hinder the purpose of maintaining an RFID. Therefore, the only other option is to increase the annual appropriations.

167. Further, the Board recognizes that the current deficit in the RFID arises from charges made either to pay for the deductibles for insurable incidents or uninsurable incidents. In either case, the Board finds that customers have benefitted from the RFID either through lower insurance rates or a lower revenue requirement. Since customers have benefitted from the RFID, the Board finds it fair that customers pay for the deficit.

168. Therefore, the Board accepts YEC's proposed three-part solution and directs YEC to make the $0.005-million reduction to the RFID appropriation it noted in reply argument in the compliance filing.

169. No intervener directly challenged the annual insurance premiums forecast by YEC for these test years. The Board has considered the annual insurance premium forecast for the test years and considers the levels of insurance premiums as reasonable in light of the evidence on the record.

3.3.8 Property taxes

170. YEC's property taxes are forecast to increase by $0.056 million in 2012 over 2009 approved costs, and by an additional $0.014 million in 2013 over the 2012 forecast. No objections or concerns were brought forward by any party with respect to property taxes.

Table 16. **Property Taxes ($000)**[97]

	2009 GRA Compliance	Actual 2009	Actual 2010	FYF 2011	GRA 2012	GRA 2013
Property Taxes	256	288	291	297	312	326

Views of the Board

171. The Board accepts the amount for property taxes as filed by YEC for the 2012 and 2013 forecast years as these increases are reasonable based on the information provided on the record.

[97] CW final argument, page 16.

3.4 Rate base, depreciation and amortization

172. YEC stated in its Application that rate base "…includes all investment providing service to ratepayers, as well as components of necessary working capital. It comprises property, plant and equipment (net of depreciation), deferred study and other costs, reserves set aside for various purposes and working capital…"[98]

173. Capital additions, including deferred charges and reserves (stabilization mechanisms) are discussed in Section 5 below. YEC proposed a forecast mid-year rate base of $223.0 million for 2012 and $241.7 million for 2013.

174. Mid-year net plant in service [unamortized deferred costs (excluding rate case expense) plus physical plant net of depreciation] is forecast at $383.13 million for 2012 and $399.57 million for 2013. The increases to net plant in service over the 2009 GRA are due to the inclusion of the Mayo B hydro generation facility, the second stage of the Carmacks-Stewart Transmission Project and the Aishihik Third Turbine.

175. Proposed forecast depreciation charges are $7.813 million for 2012 and $10.012 million for 2013. The changes in the amounts compared to the forecast 2009 GRA amount reflect the additions to net plant in service as well as YEC new depreciation study.

176. YEC undertook a review of its depreciation rates and provisions. The review resulted in a material change in YEC's service lives for certain major assets. Certain assets, including certain hydro plant, diesel production and main transmission assets were determined to have longer service lives than calculated in YEC's prior depreciation study.[99] The implementation of the study findings resulted in decreases to depreciation expenses of $2.307 million (net of customer contributions and amortization of fire insurance recoveries) for 2012 and a decrease to depreciation expense (net of customer contributions and amortization of fire insurance recoveries) for 2013 of $2.392 million based on forecast amounts.

177. LE noted that the new depreciation study undertaken by KPMG resulted in a 33-percent[100] reduction in depreciation expense. The reduced depreciation rates chiefly stemmed from increasing the amortization period for structures and improvements from 40 years to 72 years and for reservoirs, dams and waterways from 50 years to 103[101] years. LE noted that "The small hydro facilities in Yukon probably should not be compared to the very large facilities that Manitoba Hydro, BC Hydro and other provincial utilities have, so I believe that 103 years is too long when in a review only 7 years ago the number was left unchanged at 50 years. Similarly "structures and improvements" at 72 years appears to be too long compared to 40 years as reviewed just 7 years ago."[102]

98 Application, page 3-20.
99 YEC's 2005, Required Revenues and Related Matters Application.
100 LE final argument, page 8, section 14.
101 CW-YEC-1-22-Revised, Table 1.
102 LE final argument, pages 8-9, section 14.

178. UCG requested that the Board direct "YEC to specifically identify the net impact that the proposed change to depreciation will have in each of the test years and going forward since the rate base will remain higher for an extended period of time."[103]

179. Further, UCG questioned the comparability of some of the companies listed in the depreciation study.[104] UCG argued that if all the comparable companies were not listed in the study, then how could anyone confirm that all the utilities used in the study are actually comparable to YEC.[105] It submitted that the Board could not base its decision on depreciation rate changes on the KPMG study since there is no evidence that the companies are comparable to YEC.

180. In reply, YEC stated that any issues or queries related to the depreciation study were addressed in the first round of IRs. There were no follow-up questions on the depreciation study in the second round of IRs. No parties required KPMG to attend the hearing and no parties filed evidence regarding depreciation.[106]

181. YEC noted that KPMG was provided with YEC's asset information and retirement history in the Application, in the IR responses and in the hearing.[107] With respect to the comparability of the utilities used in the study, no evidence was proffered to contradict the evidence of the KPMG study.

182. Finally, YEC stated that the net impact of depreciation changes was fully addressed in response to UCG-YEC-1-36.[108]

Views of the Board

183. The Board observes that there is no evidence on the record to contradict the KPMG study that the revised amortization periods for structures and improvements should change from 40 years to 72 years, and for reservoirs, dams and waterways from 50 years to 103 years.

184. Regarding the concerns related to the comparability of the utilities used in the KPMG study and the net impact resulting from the depreciation changes, the Board is satisfied with the responses to UCG-YEC-1-38(b)[109] and Attachment 1[110] to YECL-YEC-1-55 (a), that those concerns have been adequately addressed by YEC. Therefore, the Board accepts the depreciation study and adjustments employed by YEC for this test period.

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103 UCG final argument, paragraph 249.
104 Application, page 10-10.
105 UCG final argument, paragraph 251.
106 YEC reply argument, page 79.
107 Application page 10-9; YECL-YEC-1-58; and Hearing Transcript Volume 3, November 14, 2012, pages 509 and 510.
108 YEC reply argument, page 81.
109 In this response, YEC noted that "Comparable companies were selected on the basis of owning and operating the same type of hydro and electrical generation and transmission assets as YEC."
110 In Attachment 1, the discussion of the comparable company method provides further insight as to the methodology and the comparable utilities.

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

185. Capital structure, return on equity (ROE) and return on debt are discussed in Section 3.5 and Tab 8 (ROE) of the Application. YEC proposes a return on rate base of $12.345 million for 2012 and $14.130 million for 2013.

186. In its Application, YEC stated that its rate base is financed by two main sources of capital.[111] Those sources are long-term debt and shareholder equity. The equity return is partially governed by Section 2 of OIC 1995/90 as amended by OIC 1998/32. Since the 1998 rate revision, YEC's return on equity has been set by reference to the British Columbia Utilities Commission (BCUC) formulaic approach.

3.5.1 Costs of debt

187. Long-term debt for YEC arises from the following sources:

- Yukon Development Corporation (YDC) Refinancing
- YDC Mayo B Promissory Note
- New YDC Loan (2011)
- New YDC Loan (2012)
- New YDC Loan (2013)
- TD Canada Trust Note

Details on the above are contained on pages 3-25 to 3-27 inclusive and Schedule 11 (page 7-15) of the Application. YEC forecasts year-end long-term debt levels of $142.813 million for 2012 and $144.090 million for 2013.[112]

188. CW stated that the forecast rate of new debt of five percent was based on the rate obtained for debt issued in 2010. CW added that, in the past, YEC forecast its debt at the long-term Canada bond rate plus 120 basis points[113] (a formulaic approach). CW submitted that based on the formulaic approach, the 2012 cost of debt should be a maximum of 3.97 percent. Similarly for 2013, the forecast cost of new debt should be 3.58 percent.

189. In its argument[114], UCG mirrored the submissions of CW.

190. LE, in its reply argument, said "A formulaic approach to setting the cost of debt from YDC would be appropriate if YDC was supplying this debt from its internal cash resources; however, YDC has had to borrow money at 5%. If this is the money that YDC is now loaning to Yukon Energy the actual cost of that debt should be used as YEC's debt cost."[115]

191. YEC argued the approach suggested by CW and UCG was "cherry picking". YEC maintains the percent cost of debt forecast in the Application is based on the bond secured by YDC in June of 2010, and was the best market information available to YDC

[111] Application, page 8-1.
[112] Application, page 7-15.
[113] CW final argument, paragraph 49.
[114] UCG final argument, pages 65 and 66.
[115] LE reply argument, section 9.

at the time that the Application was prepared. YEC noted that if the cost of debt was to be lowered based on information available subsequent to the Application, then other information such as lower Minto mine loads should also be considered.[116]

Views of the Board

192. 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.[117]

193. The Board has a concern with YEC's use of the cost-of-debt rate from the issuance of a $100-million 30-year bond secured by YDC in June of 2010. This concern is that the issuance of the 30-year bond was nearly two years before YEC's Application was filed with the Board and, based on that timing, does not reflect market conditions at the time of the Application. Using rates that reflect market conditions at or about the time of the Application reflects consistency in the Application process, as the costs for debt will coincide on a similar timeframe basis with the other costs and revenues in the Application. With this particular case, the Board is of the view that better information was available to YEC, in terms of cost of debt, and this information should have been included in the Application. The evidence on the record is:

> New YEC debt required at the end of each fiscal year has typically been provided by YDC. Since the early 1990s, interest rates on such new YDC debt have been set each year based on a proxy for market conditions (i.e., long-term Canada bond rates plus 120 basis points to reflect the estimated spread for YEC debt guaranteed by the Yukon Government).
>
> In 2010, YDC went to market for new long-term debt ($100 million bond with a 30 year term) and secured an interest rate of 5%. When preparing the current GRA forecasts in late 2011, YEC used this 5% most recent market-based long-term interest rate for the new long-term debt forecast for the test years. No other forecasts or analysis were employed.[118]

194. Based on the above, the Board finds that there is little reason to depart from the previous approach and YEC has not provided any explanation for not conducting any further analysis or departing from the previous approach. The Board accepts the recommendation of CW, which was supported by UCG, and directs YEC in its compliance filing to use 3.97 percent as the forecast cost for new debt for 2012 and 3.58 percent as the forecast cost for new debt for 2013.

116 YEC reply argument, page 37.
117 CW reply argument, paragraph 28.
118 CW-YEC-2-3(a).

3.5.2 Capital structure and return on common equity

195. YEC has maintained the same capital structure since 1992.[119]. Thus the capital structure has remained at 60-percent long-term debt and 40-percent equity.

196. CW argued that YEC's capital structure was based on a 1990 study by RBC Dominion Securities and that the financial risks for YEC in 1990 are different than those for YEC in 2012. Given the time lapse since that 1990 capital structure study, CW submitted that now is the time to re-evaluate the capital structure.[120]

197. Referencing AUC Decision 2011- 474 as a guide, CW submitted that since YEC's distribution assets are relatively small compared to generation and transmission assets, distribution did not add to YEC's risk profile. CW added that YEC's generation risks are no different than a transmission facility owner in Alberta and therefore submitted that YEC's capital structure should not contain more than 37-percent equity.[121]

198. YEC, in its argument, maintained that it wanted to retain its simplified ROE approach based on available benchmarks for capital structure and ROE. YEC stated it was not seeking any adjustment to its longstanding capital structure of 40-percent equity and 60-percent long-term debt.[122]

199. CW, in reply, noted that its recommendation is "… consistent with the AUC's methodology of setting a generic rate of return and adjusting a utility's equity thickness for the risks the utility faces."[123] CW further argued that YEC's past practice regarding capital structure is irrelevant to this Application, as the financial risks faced by YEC are different today than they were in 1990 and that CW's recommendations are consistent with the AUC.

200. YEC replied that "… the current proceeding provides no reasonable or tested evidence upon which the Board could support a revision of YEC's capital structure, or assess YEC's capital structure based on AUC methods."[124] YEC further submitted that there is no practical basis for comparing YEC with the Alberta utilities and that the assertions in CW's argument are either of no help to the Board or wrong.[125]

Views of the Board

201. The Board observes the following from YEC:[126]

> Yukon Energy notes that the current proceeding provides no reasonable or tested evidence upon which the Board could support a revision of YEC's capital structure, or assess YEC's capital structure based on AUC methods. Specifically, Yukon Energy submits that the Board must reject CW's argument that YEC's risk

119 Application, page 3-24, footnote 18.
120 CW final argument, paragraph 44.
121 CW final argument, paragraph 46.
122 YEC final argument, page 10.
123 CW reply argument, paragraph 26.
124 YEC reply argument, page 76.
125 YEC reply argument, page 77.
126 YEC reply argument, pages 76-77.

> can be re-evaluated according to AUC's evaluation in 2011-474 of appropriate capital structures of the utilities it regulates as provided in response to CW-YEC-1-41.

202. YEC's capital structure of 60-percent debt and 40-percent equity has been previously approved by the Board, most recently through Board Order 2009-8. Nothing on the record of this proceeding persuades the Board to alter the applied-for and previously approved capital structure for YEC.

Return on common equity

203. For the 2005 Required Revenues and Related Matters proceeding and the 2008-2009 YEC GRA, YEC proposed that the return on equity, set in reference to the benchmark BCUC, should attract a risk premium. A risk premium for a low-risk utility was set for YEC at 52 basis points above the BCUC generic amount and then was reduced by 0.5 percent in accordance with the OIC. Board Order 2009-8 stated that the BCUC approach including the 52 basis point risk premium would continue to be a precedent for Yukon until otherwise ordered.[127]

204. In its Application, YEC noted that the BCUC has initiated a generic cost-of-capital proceeding but that an up-to-date benchmark for a low-risk utility is not expected to be available before the end of 2012.[128]

205. YEC added that:

> Since the late 1990's Yukon Energy has relied upon a low risk utility benchmarking approach along with a reasonable risk premium of 52% (based on BCUC precedents for similar electric utilities) as a simplified approach that reduces overall cost to the ratepayer through eliminating the requirement of costly expert assessment and testimony.[129]

206. YEC said that the BCUC low-risk utility benchmark had not been reviewed since 2009, and therefore, YEC looked at the AUC Generic Cost of Capital proceeding, for which a decision was issued in December of 2011[130], for a more up-to-date comparable.

207. Using the AUC ROE benchmark of 8.75 percent, YEC added the 52-basis-point risk premium as was applied in YEC's 2008-09 GRA, and then subtracted 50 basis points pursuant to the direction provided in OIC 1995/90. The result proposed by YEC is a ROE of 8.77 percent for both 2012 and 2013.

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127 Application, page 8-2.
128 Application, page 8-2.
129 Application, footnote 20, page 3-27.
130 AUC Decision 2011-474, released December 8, 2011; 2011 Generic Cost of Capital.

208. In argument, CW said it continues to support the formulaic approach to determining ROE that it supported in YEC's 2008-09 GRA and quoted from its argument in YEC's 2008-09 GRA:[131]

> A generic formula provides a fair and objective method of determining what can be a contentious issue that can be costly to the utility and customers to resolve. The City considers that the formulaic approach to ROE provides for an efficient process and serves to reduce regulatory costs.

209. CW further added that it supported YEC's decision to change the benchmark from that used by BCUC to that used by AUC as "The timing of the BCUC's process is inconvenient for these proceedings."[132] However, it argued that YEC had cherry picked features of the BCUC and AUC methods and had incorrectly applied the AUC method because in the AUC method, capital structure is adjusted for YEC specific risks and not to provide a 52-basis-point premium to ROE as compensation for those risks. Therefore, CW recommended that ROE for YEC be 8.25 percent for 2012 and that same amount be a placeholder for YEC's 2013 ROE, pending the results of the AUC's 2013 final generic return-of-equity determinations are made.[133]

210. UCG stated:

> It is clear in the evidence that YEC did not do cost of capital studies that would justify a mix and match approach between B.C. and Alberta precedents to arrive at a final figure. Without a risk comparison between the low risk utility used from the BCUC and the most recent Alberta ROE from the generic cost of capital hearing, there is no reliable basis for using the existing adjustment mechanism of 52 basis points. [134]

211. UCG submitted that if the AUC ROE was to be used as the benchmark ROE for YEC, then there should not be any additional risk premiums allowed. Therefore, UCG recommended an ROE of 8.25 percent for YEC for 2012 and for 2013.

212. YEC, in its argument, confirmed that based on the 2009 BCUC benchmark ROE, which is still in effect, the ROE for YEC for the 2012 and 2013 test years would be 9.52 percent. YEC further affirmed that for the 2011-2013 test years, the NWT Public Utilities Board approved ROEs of 9.3 percent for Northland Utilities (YK) and Northland Utilities (NWT) and allowed for equity ratios of 43.5 percent and 44 percent respectively.[135]

213. CW replied that "YEC's method can only be considered valid if the numbers are reconciled to account for the differences between the two Commissions' approaches"[136] (BCUC and AUC).

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[131] CW final argument, page 17 of 22; quoting CW's final argument dated May 22, 2009, page 15 of 26 from YEC's 2008-2009 GRA.
[132] CW final argument, paragraph 41 (footnote omitted).
[133] CW final argument, paragraphs 42 and 43.
[134] UCG final argument, paragraph 362.
[135] YEC final argument, page 11.
[136] CW reply argument, paragraph 23.

214. UCG in its reply argument stated:[137]

> … [T]he comparison that YEC makes on page 11 of its Argument between its proposed ROE with those awarded in the Northwest Territories is of no value since the circumstances in the Northwest Territories are completely different with respect to regulatory, political, economic and operational circumstances of the utilities referenced. YEC has provided no evidence in this proceeding to allow the YUB to draw any comparisons between the two jurisdictions.

215. YEC in its reply argument said:

> Specifically, Yukon Energy submits that the Board must reject CW's argument that YEC's risk can be re-evaluated according to AUC's evaluation in 2011-474 of appropriate capital structures of the utilities it regulates as provided in response to CW-YEC-1-41. There is no practical basis for comparison of YEC, either in size or in activities, to the listed Alberta utilities - and CW's arguments in this regard are either of no help to the Board, or totally wrong (such as CWs' assertion that YEC's isolated grid ensures "that it can sell all the power it produces"). CW's arguments in this regard totally also disregard past findings of the YUB, including Board Order 2009-02 that reviewed (page 29) YECL's acknowledgement that relative to YECL, YEC has more risk - and the Board's determination to set a risk premium for YECL in 2009 that was lower than for YEC. In summary, past Board findings highlight the extent to which, no matter what CW may argue based on AUC experience, YEC's mix of utility functions are in fact more risky than those of a more-distribution-focused utility in the same northern jurisdiction.[138]
>
> …
>
> As set out in the Application, the 8.77% ROE was determined using only a portion of the AUC methods – and there is, in Yukon Energy's view, insufficient evidence to fully apply the AUC methods (including dealing with capital structure adjustments) to YEC, and Yukon Energy i[n] any event strongly opposes any change to its long established capital structure, and does not support applying the full AUC approach to determine Yukon Energy's ROE.[139]

216. YEC reiterated from Board Order 2009-8, that the Board continues to be of the view that relying on a generic ROE from a different jurisdiction is the most efficient means of addressing an inherently complex and costly matter.[140]

137 UCG reply argument, paragraph 23.
138 YEC reply argument, pages 76-77.
139 YEC reply argument, page 77.
140 YEC reply argument, page 78.

Views of the Board

217. In Board Order 2009-8, Appendix A – Reasons for Decision, the Board held the following views:

> The Board strongly agrees with the part of the YECL argument that states:
>
> > The proposal to rely on the generic ROE as a point of departure was intended to be the most efficient means of addressing what is inherently a complex and costly matter, given the current state of ROE determination throughout Canadian regulatory jurisdictions.
>
> YECL covers a geographically dispersed area with a relatively small customer base. It is incumbent upon the Board to explore ways that yield regulatory efficiency and yet provide fairness to all interested parties. In this regard, the Board supports a formula-based approach to determining ROE issues. YECL used the AUC Generic Cost of Capital as its starting point while YEC supports the BCUC formula. CW was also supportive of the BCUC generic cost of capital. Both YECL and YEC have argued that reference to a formula approach is efficient from a regulatory efficiency perspective. To reference a generic cost-of-capital approach from another jurisdiction, the Board must answer the following questions:
>
> - Which generic cost-of-capital model should be used and from which jurisdiction?
> - Should a risk premium be applied?
> - If a risk premium is applied, what risk premium level should be applied to YECL?
>
> The Board continues to be of the view that relying on a generic ROE from a different jurisdiction is the most efficient means of addressing an inherently complex and costly matter. The Board strongly believes that such an approach is the most efficient manner for a jurisdiction such as Yukon.
>
> The Board considers that the BCUC approach has been successfully applied to both utilities under this Board's jurisdiction and has resulted in fair returns to both utilities.
>
> Therefore it is determined that the BCUC approach is a precedent for this jurisdiction and will continue to be the precedent for this jurisdiction until otherwise ordered by this Board. Further, the Board accepts the risk premium of 52 basis points, as has been previously established, for YEC.[141]

The Board confirms that the use of a generic cost-of-capital model from another jurisdiction is the most efficient method for determining ROE for utilities under the

[141] Appendix A to Board Order 2009- 8 – Reasons for Decision at pages 53 to 54.

jurisdiction of this Board. However, the questions remain as to which generic cost-of-capital model should be used and from which jurisdiction.

218. The precedent for this jurisdiction has been to use the BCUC model. However, as YEC has noted, the BCUC model has not been updated since 2009, and therefore, YEC turned to the AUC model as its most recent decision[142] covered the years 2011 and 2012.

219. For this decision, the Board accepts the decision by YEC to change models from the BCUC model to the AUC model because it provides more up-to-date information and accounts for significant changes in the economy as indicated in paragraph 28 of that decision (AUC Decision 2011-474):

> … the Commission finds that corporate bond spreads had begun to recover at the time of the 2009 hearing but had far from fully recovered. The Commission also finds that, in contrast, by the time of the 2011 hearing, bond spreads had largely, although not completely, returned to historic levels.

220. However, as the Board has previously ruled that the BCUC model is the precedent for Yukon, the Board may, in a future proceeding, allow the BCUC model to continue as the precedent if it is current. The next question the Board must respond to is whether a risk premium should be applied to the ROE determined in a different jurisdiction.

221. YEC argued that a risk premium was appropriate as it would align YEC's ROE with those recently determined for the Northland Utilities in the NWT.

222. Both CW and UCG argued against the 52-basis-point risk premium for YEC over the determined AUC ROE. CW submitted that if YEC had additional risk, then the risk premium should be reflected in the equity thickness of YEC. UCG submitted that no evidence has been provided in this proceeding that would allow the Board to draw any comparisons between the YUB jurisdiction and the NWT Public Utilities Board jurisdiction.

223. Comparability with other utilities was discussed in the hearing, as follows:

> In other words, you've got a situation where
> you've got apples and oranges in relation to the ROE.
> A. MR. OSLER: You're asking me if I agree
> with you?
> Q. Yes.
> A. MR. OSLER: No. At the level of -- if it
> was really apples and oranges, then we shouldn't do it. I
> think it's fair to say that the BC approach and the Alberta
> approach are different in the area that you're describing.
> The assumption that we're putting forward for the sake of
> expediency if you like in the sense of trying to getting an
> answer that is reasonably cost effective and useful for this

[142] AUC Decision 2011-474, released December 8, 2011; 2011 Generic Cost of Capital.

Board.

We're saying we didn't think that the BCUC's most recently available, from 2009 I believe, benchmark number, well over 9 percent, was current or reflected the situation that we would recommend for the Board. We don't have anything else from BC. We don't have anything else from a comparable regulator who is taking a risk-free benchmark and adding to the interest rate as BC did.

We went to Alberta who uses a different approach, adjust the equity -- as you say it's an apples and oranges variation -- and thought that their risk-free benchmark could be utilized in the way we have suggested and we could get a quick determination of something that was fair and reasonable for all parties.

We have no interest in trying to get into the complexities of adjusting the equity base in Yukon Energy or getting expertise to try and do that. We think the approach that's been going on since the company was formed to try and keep it at 40 percent equity has met the test of time and various different people in government and everything else, and we would very much like to keep that as a firm rock upon which we can build other things.

I think that's about as blunt as I could be, sir, in terms of what we're doing. And if somebody has a better option, we were sure they would come forward with evidence in this hearing and offer it.[143] [underlining added]

…

Q. Now, and again if you've addressed your mind to this in making the request? Do you believe that the utilities, given the risk premium that was attached to the utilities regulated by BCUC and the comparable utilities -- all right. Let me -- do you believe that the utilities are comparable to those that are regulated by the AUC and BCUC for the type of utilities, the risk, the low-risk utilities, in order for the premium to be -- the risk premium to be applied, continue to be applied?

A. MR. OSLER: That is an assumption that is implicit in what was filed. It wasn't based on calling in experts to, you know, give an opinion on that. We've -- we're confident that the Board would have advisers who could review this.

But as I said before, the basic problem was that relying on what we've used before and the BCUC process, the last order that they had given of a benchmark bond in 2009 was for Terasen at 9.5 percent, and we did not think that that was an appropriate number to bring forward at the

143 Hearing Transcript Volume 2, November 13, 2012, starting at page 289, line 8, and ending at page 290, line 20.

> current time, but we didn't have a better one from BCUC. And for the purposes of cross-checking it, we noticed that an Alberta-based utility active in Northwest Territories had used some reference points to their own situations in Alberta. So again, not being as knowledgeable as others, we thought it was probably a reasonable approach to keep it simple. But I have to say that's about the limit of the depth of the investigation. [144]

224. It is clear to the Board that there are differences in the benchmark jurisdictions. The BCUC determines a generic ROE for a benchmark utility and then applies a risk premium specific to the risk profile for each utility relative to the benchmark utility. The AUC determines a generic ROE and then adjusts for the risk profile for each utility by adjusting the equity thickness.[145]

225. However, the Board cannot accept the request for a risk premium for YEC when YEC states: “We went to Alberta who uses a different approach, adjust the equity -- as you say it's an apples and oranges variation …”[146] If the models are not similar, the risk premium from one model cannot be automatically transferred to the other model.

226. In Table 1 of YEC’s response to CW-YEC-1-41(a), the equity ratio for electrical transmission facility owners (TFOs) under AUC jurisdiction was 36 percent to 37 percent. For electrical distribution companies (Discos) under the jurisdiction of the AUC, the equity ratio was determined to be from 39 percent to 41 percent.

227. The Board finds that as the AUC model does not allow for an equity premium, and since it is the model that is followed, no equity premium is allowed.

228. In addition, on pages 10-16 and 10-17 of YEC’s Application (KPMG Depreciation Study), using the surviving original costs at December 31, 2010, YEC’s generation assets account for approximately 51 percent of the original costs, transmission assets account for about 35 percent of the original costs and distribution assets are just over four percent of the original costs. This shows that transmission assets make up a significantly larger proportion of the YEC asset mix than distribution assets. By extension, using the AUC model, the equity thickness for YEC would be closer to the TFOs listed in Table 1 of CW-YEC-1-41(a), than to the discos represented in the same table. However, as determined above, by retaining YEC’s equity ratio at 40 percent, the Board is of the view that YEC is appropriately compensated for any additional risk premium it has relative to the Alberta utilities including the existence of its generation assets.

229. With respect to the comparison of YEC relative to the two Northland utilities, other than the fact that those two utilities operate in the Canadian north, no evidence of comparability with YEC was provided.

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144 Hearing Transcript Volume 3, November 14, 2012, starting at page 649, line 24, and ending at page 651, line 1.
145 CW-YEC-1-41(a), Table 2.
146 Hearing Transcript Volume 2, November 13, 2012, page 290, lines 3 to 5.

230. In summary, the Board has determined that the simplified approach is the approach to be used in determining the ROE for utilities under its jurisdiction. The simplified approach was based on the precedence of the BCUC formulaic model. In this proceeding, since recent results of the BCUC model are not available, YEC can use the benchmark results from the AUC model. Therefore, the Board directs YEC in its compliance filing to use an ROE of 8.25 percent.[147]

3.6 Stabilization mechanisms

231. Historically, YEC has used two mechanisms to stabilize rates and revenues.

232. In accordance with Section 8 of OIC 1995/90, the Deferred Fuel Price Account or Rider F was created. This deferral account records the variance in consumed fuel prices, on a per-litre basis, relative to the most recent GRA-approved fuel prices. In addition, on a quarterly basis, YEC credits the account with all variations (positive or negative) of secondary sales relative to the most recent GRA-approved price.[148] YEC has proposed changes to Rider F in this Application, which will be discussed in the section below.

233. The second stabilization mechanism is the Diesel Contingency Fund (DCF) which was established in the 1996-97 Negotiated Settlement. A description of this account is found on pages 3-28 to 3-29 and Appendix 3.2, Attachment 3.2 of the Application. The balance in the DCF as at December 2011 is $0.902 million. Other than interest, no transactions have been put through the account since December 31, 2007. YEC has proposed significant changes to the DCF which will be examined more fully in that section.

3.6.1 Rider F

234. As noted above, YEC has proposed changes to Rider F whereby any secondary sales after January 1, 2012 would be credited to the DCF. Therefore, Rider F would not be affected by changes in the ongoing quarterly adjustments to the prices of secondary sales. These proposed changes will be discussed in the DCF section below.

3.6.2 Diesel contingency fund (DCF)

235. Board Order 2011-15 (YEC-YECL Rider F Decision) directed YEC as follows:[149]

> The Board accepts the commitment of YEC to address all DCF issues in the next GRA and directs YEC to address any changes necessary in operating rules, administration and revised revenue requirements pertaining to the DCF in its next GRA.

236. YEC's response to that direction is found on pages 3-28 to 3-29 and Appendix 3.2 of the Application.

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[147] 8.25 percent is determined by taking the AUC benchmark rate of 8.75 percent and reducing it by 50 basis points in accordance with OIC 1998/32 (Section 2).

[148] Application, page 3-28.

[149] Board Order 2011-15, Appendix A – Reasons for Decision, page 9.

237. The DCF was created (1996-97 GRA Negotiated Settlement) when the Faro mine was operating and the DCF only pertained to the WAF system. The fund was established to ensure that ratepayers, rather than YEC, covered the risk of changes in grid diesel generation due to fluctuations in hydro generation resulting from factors outside of the utility's control (such as drought conditions). The effect of the DCF is to allow rates to be based on long-term forecast hydro generation versus short-term hydro generation. The effect of the DCF is to shield rates from volatility due to hydro generation variances based on fluctuating water levels.

238. YEC added that the connection of the WAF and MD grids and the addition of new hydro facilities (Mayo B, Aishihik Third Turbine) have necessitated a review and update of the DCF. The Board also notes that the Mayo A runner improvement should have some positive impact on future hydro generation.

239. Among the changes, YEC has proposed that the fund operate outside of rate base, that Fish Lake hydro output is not included and that diesel would be considered permanently on the margin. Details of YEC's proposal are found in Attachment 3.2: DCF Term Sheet: Updates for YEC Grid starting at page 3.2-1 of the Application.

240. In argument, YEC stated:[150]

> The Application's forecast diesel generation reinstates the need for DCF measures to enable rates to recover diesel fuel and O&M costs based on LTA hydro generation rather than forecast actual diesel generation. Customer rates and YEC's diesel generation expenses are therefore once again to be based on forecast long term average ("LTA") diesel generation requirements related to actual grid loads rather than on YEC diesel generation requirements that fluctuate in response to changes in annual YEC hydro or wind generation availability.
>
> …
>
> The transition measures proposed in the Application for moving to full long term average diesel generation cost recovery have capped the current rate increase at 6.40% in 2012 and 6.50% in 2013. As a result, diesel generation included in the proposed revenue requirement equals 65.6% of long term average (LTA) annual costs in 2012 and 59.0% in 2013.[151]

241. CW did not oppose the reactivation of the DCF, but requested that YEC be directed to report on the DCF on a quarterly basis and the report contain a narrative indicating what action will be required for the DCF (replenishment or refund).[152]

242. The DCF was supported by LE with the caveat that 0.8GW.h of wind energy be included in the DCF calculation and the range for the DCF be set at -$4.0 million to +$20 million.[153]

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[150] YEC final argument, page 11.
[151] YEC final argument, page 22.
[152] CW final argument, page 14.
[153] LE final argument, page 9.

243. UCG stated that any changes proposed to rate stabilization mechanisms established through a GRA should only be made through a GRA. UCG supported the CW view that the DCF filings should include a narrative section. Finally, UCG added that the annual DCF filing should include working spreadsheets detailing the calculations and that parties be offered the opportunity to comment on the annual filings.[154]

244. YECL argued that Fish Lake hydro output had been incorporated in past DCF calculations and that the DCF was managed by YEC, but in the new proposal, Fish Lake hydro output was excluded. YECL asked the Board to reject YEC's DCF proposal and that the Board direct YEC to work with YECL to include Fish Lake generation in YEC's compliance filing.[155] This position was supported by UCG in reply argument.[156]

245. In reply argument,[157] CW agreed with YECL that YEC's proposal shifted generation risk from YEC to YECL through the use of the ERA (energy reconciliation account). CW said that this shift in risk should be addressed through YEC's capital structure.

246. YEC, in reply argument, said it took no issue with providing a narrative report or Excel sheets that support the annual filing to the Board; however, YEC submitted that quarterly filings would be administratively burdensome.[158]

247. YEC did not support LE's request to include 0.8 GW.h of wind energy generation for each year in the DCF calculations because no basis had been provided for that number. YEC also submitted that it was premature to recommend any positive or negative cap for the fund, and that the UCG recommendation that changes to the DCF should only occur through a GRA should be rejected. YEC also submitted that the arguments of YECL should be rejected because each utility has been separately managed since 1998 and YEC has little knowledge of how Fish Lake hydro is managed. YEC submitted that, "In YEC's opinion, the Board and interested parties would be better served if each utility managed their own transactions in this regard and defended them at their own respective GRAs."[159] YEC further added:[160]

> Any material impacts on YECL from diminished Fish Lake hydro availability would derive mainly from the ERA, in which case YECL is protected through its deferral account mechanism and its ability to recover such ERA costs through Rider D.

Views of the Board

248. The Board has several concerns with the DCF as filed by YEC. As noted above, the exclusions of the effect of Fish Lake and wind generation (generation that could in effect reduce the need or use of diesel generation) seem inconsistent with the design of

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154 UCG final argument, paragraphs 198 and 199.
155 YECL final argument, page 6.
156 UCG reply argument, paragraph 40.
157 CW reply argument, page 6.
158 YEC reply argument, page 39.
159 YEC reply argument, page 40.
160 YEC reply argument, page 41.

a fund that is set up to reduce the impact of diesel generation costs, which costs will affect customers of both utilities.

249. Secondly, as noted in the transcript,[161] the DCF has never been fully tested (it was the product of a negotiated settlement). Although it was reviewed in conjunction with the Rider F proceeding, it has nonetheless been inactive since around 1999.[162] Undertaking 23 (November 19, 2012), a continuity schedule of the DCF provided by YEC for the years 1996 to 2011 inclusive, showed no transactions in the DCF account except for interest income since 1999.

250. YEC described how the diesel generation relative to long-term hydro generation affects the fund balance:

> Q. Certainly. Well, I can -- the question is how was that
> the fund going to be billed up?
> A. MR. OSLER: Okay. Essentially the same way
> as it was before, in principle. Okay? Just start from
> there. And the fund is built up by charging -- by setting a
> pricing basis -- and I'm going to keep it at long-term
> average for the sake of this discussion because it's a bit
> simpler. Agreeing that we're not going to have the company
> paying for diesel based on what it actually burns, but we're
> going to have it pay for diesel based on the long-term
> average, okay?
> So Mr. Mollard would then enter into his
> accounts for the year essentially based on what the long-term
> average diesel requirement should have been for that load and
> he will pay that.
> How much money goes into the fund depends on
> what actual diesel was burned. If, in fact, the actual
> amount of diesel burned was less than the long-term average,
>
> then that money -- the difference between what he's paying
> and what was actually paid for diesel will end up in the
> fund, and will augment the fund.
> The fund can only get augmented that way
> unless the Board was to order, because the fund has gone
> outside its boundary, its cap, or outside its limits, order a
> special charge to replenish the fund.
> The fund would be drawn down by the opposite,
> by the -- essentially having a situation where the diesel
> requirement, in fact, was bigger than the long-term average.
> Mr. Mollard would still be paying the long-term average; the
> fund would be paying the difference between the actual diesel
> requirement and the long-term average.
> So, in that sense, it's exactly the same in
> principle as what the diesel contingency fund was doing
> before. The changes are more to do with the issue of how you
> calculate the long-term average that is applicable in a given

[161] Transcript Volume 3, November 14, 2012, page 570-571, starting at line 9 and ending at line 5.
[162] Transcript Volume 3, November 14, 2012, page 571, starting at line 8 and ending at line 14.

year and taking into account in doing that the integrated
grid that exists today rather that (sic) just the Whitehorse
Aishihik Faro system that the fund applied to before.
I'm talking at a very high level, but I think
that's the essence of it.[163]

251. In response to additional questions regarding rate impacts, if the DCF were to cease, YEC stated it usually is not an isolated event, droughts tend to happen over a series of years, and the resultant numbers to the fund would be large.[164] YEC added that it is a ratepayer risk, that there would be questions regarding how the amounts would be collected from ratepayers, and that reacting when a drought occurs would be the worst way to handle the situation.

252. The Board observes that YEC stated that the DCF is designed to smooth customer rate changes and changes in forecast diesel costs due to variability in existing grid hydro generation. The DCF is to provide firm rate customers with appropriate longer-term price signals and prevent short-term price variability. YEC added that since there is no interconnection with external grids, there were no market signals for consumers.[165]

253. The Board is concerned that the DCF masks market signals and that, in times of a drought, consumers will be removed from the signal to reduce consumption. The problem with smoothing rates is that it mutes market signals and hence consumer behavior.

254. In addition, the Board notes that the use of the fund in the past has been sporadic as evidenced by the fact that the fund has not been active since 1999. Such periods of infrequent use raise issues of intergenerational inequity in that a consumer contributing to a fund today may benefit another consumer several years later.

255. Given the above concerns, the Board does not approve YEC’s proposed DCF but directs YEC to provide a revised DCF proposal. In the revised DCF proposal, YEC is to incorporate other non-diesel generation facilities (wind, Fish Lake hydro) forecasts into its model. In addition, YEC is to incorporate the suggestions of CW and UCG as to how DCF transactions are to be reported. Further, in that submission, YEC is to provide an example of approximately five years of transactions which will show how the balance in the DCF will change and how those changes will be reported. Finally, YEC is to work with YECL, and the two utilities will provide a joint recommendation on how the DCF will affect the Energy Reconciliation Account in Rate Schedule 42 and any proposed wording changes to that rate schedule. The Board will leave it to the discretion of YEC and YECL as to when the revised DCF proposal is to be filed with the Board. Given the foregoing, the Board does not approve YEC’s requests regarding the DCF and therefore does not approve YEC’s proposed changes to Rider F. Secondary sales, as they occur, will continue to be credited to the Rider F account.

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163 Transcript Volume 3, November 14, 2012, page 573 starting at line 8 and ending at page 574, line 22.
164 Transcript Volume 3, November 14, 2012, page 574 starting at line 23 and ending at page 578, line 16.
165 YUB-YEC-1-29(b).

4 Rates

4.1 Overview

256. YEC, in its Application, stated that the rates are designed to recover the revenue requirements as set out in the Application less non-rate revenues for each of the test years. Generally, YEC's rate revenue is collected from charges for firm rates and secondary sales. In this Application, since diesel is forecast to be on the margin, YEC is forecasting 0 GW.h[166] of secondary sales. If any secondary sales occur, YEC has proposed that those revenues be credited to the DCF.

4.2 Secondary energy rate design

257. Secondary energy sales refers to offering interruptible power to YEC or YECL customers who qualify under Rate Schedule 32. To qualify, customers must have an alternative fuel source to provide space or process heating and the power must be in excess of normal consumption and represent incremental electric energy usage displacing an alternative fuel source for space or process heating. YEC has not proposed changes between the relationship between wholesale and retail secondary energy rates.

4.2.1 Retail secondary sales rates (Rate Schedule 32)

258. YEC, in its Application, referred to Board Order 2005-12 and stated that:

> In order to address fuel price related variance in income, the Rider F Deferred Fuel Price mechanism was used to normalize the secondary sales revenues and act as a natural hedge to the Rider F account, reducing variability that would otherwise be charged through the joint Yukon Energy/Yukon Electrical rate rider.[167]

259. In this Application, YEC has proposed to discontinue crediting the Rider F account with secondary sales and has instead requested approval, in the event that any secondary sales occur, to credit those revenues directly to the DCF account. YEC summarized their proposal as:[168]

> Assigning secondary sales revenues to the DCF ensures that all such temporary revenues from surplus hydro conditions will go to funding future fossil fuel generation due to below average water conditions.

Views of the Board

260. As a result of the Board's determination regarding the DCF, YEC's proposed changes for secondary sales is moot. YEC is directed to continue applying any secondary sales to the Rider F account.

166 Application, page 4-2.
167 Application, page 4-4.
168 Application, page 4-4.

4.2.2 Low-grade ore processing secondary energy (Rate Schedule 35)

261. The prerequisites for this rate schedule have not been met. As the forecast for sales to Rate Schedule 32 is 0, so are the forecast sales for this rate schedule. If the prerequisites were to be met and some sales were available to this rate schedule, YEC has proposed that any such sales be credited to the DCF.

Views of the Board

262. The Board determination regarding the DCF has rendered YEC's proposed changes for Rate Schedule 35 moot.

4.3 Major industrial firm rates

263. The definition for Major Industrial Customers (used by YEC) comes from OIC 1995/90 and describes those customers as "engaged in manufacturing, processing, or mining and whose peak demand for electricity exceeds 1 MW."[169]

264. YEC noted in the Application that the rates proposed for major industrial firms rates conform with OIC 2012/68.

Views of the Board

265. No changes were proposed to Rate Schedule 39. The Board approves the continuation of this rate schedule.

4.4 Non-industrial firm retail rates

266. Firm retail non-industrial rates are to be equal throughout Yukon as prescribed by OIC 1995/90, as amended by OIC 2008/149 and OIC 2012/68, which states:

> 2.1(1) the Board must ensure that rate adjustments for all retail customers apply equally, when measured as percentages, to all classes of retail customers.

267. Section 2.1(1) applies until December 31, 2013.

268. YEC has stated that the use of Riders J (2012) and R (2013) conform with current OICs.

Views of the Board

269. No changes were proposed nor issues brought forward. The Board approves the continuation of these rate schedules.

[169] Application, page 4-5.

4.5 Wholesale rates

270. OIC 1995/90 sets out the structure for the wholesale rate charged by YEC to YECL. Chiefly, through this rate, YEC must recover costs which are not recovered from its other customers. A second requirement of OIC 1995/90 is:

> The wholesale rate "shall include appropriate provisions to ensure that Yukon Energy Corporation will recover its costs for retail and major industrial power service with adoption of the rates for retail power customers and major industrial power customers as specified herein." [170]

271. YEC described this rate (Rate Schedule 42) as an energy-only rate with two levels: one level for when the WAF system does not have diesel on the margin, and a second level for when diesel is on the margin.

272. With respect to the second level, the Energy Reconciliation Adjustment (ERA) is triggered when diesel is on the margin. The ERA is designed to ensure that YECL receives a full pass through of the incremental costs[171] of diesel generation and to ensure that YEC recovers its costs[172] when diesel is on the margin.

273. In this Application, based on YEC's DCF proposal, YEC also proposed that the ERA provisions in Rate Schedule 42 [Wholesale Primary (YEC)] be triggered on an ongoing basis effective January 1, 2012. With this proposed change "…charges to Yukon Electrical will be adjusted when changes in actual Yukon Electrical wholesale purchases (relative to Yukon Energy's most recent test-year forecast for such purchases) result in changes to Yukon Energy's costs incurred for diesel generation, whether such costs are incurred through adjustments in actual diesel generation or through adjustments in DCF payments or recoveries."[173]

274. Therefore, page 4-13 of the Application shows YEC's proposed wording change to Rate Schedule 42.

275. LE supported YEC's proposed changes.[174]

276. UCG recommended that the Board not approve YEC's proposal until available alternatives have been evaluated.[175]

277. YECL identified several concerns with YEC's proposed adjustments to Rate Schedule 42:[176]

- YECL was not consulted regarding the proposed changes

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170 Application, page 4-11.
171 Application, page 4-11; this applies when diesel is on the margin at long-term average water flows.
172 Application, page 4-11; as required by OIC 1995/90 Section 7(b).
173 Application, page 4-12.
174 LE final argument, page 11.
175 UCG final argument, paragraph 317.
176 YECL final argument, paragraphs 16-21 inclusive.

- the ERA as proposed by YEC may not allow YECL to recover its prudently incurred costs
- the ERA charges may have a material impact on YECL and its customers
- YECL has to carry a forecast risk based largely on a forecast prepared by YEC
- YECL does not accept YEC's wholesale forecast which could result in erroneous ERA charges
- the proposed ERA has no mechanism to account for system growth
- the designed ERA process is administratively inefficient

278. YECL opposed the ERA mechanism proposed by YEC and asked the Board to direct YEC to prepare and file a deferral account to address increased diesel costs. The deferral account is to be administered by YEC and dispensed by YEC and should form part of YEC's compliance filing.

279. YEC, in reply argument, noted UCG did not propose any alternatives to the ERA to be evaluated and therefore the UCG position should be rejected by the Board. YEC further responded that, based on past decisions of the Board, there is no basis to delay the ERA amendments as proposed and that YECL's Rider D protects YECL from cost impacts from load forecast variance derived from ERA cost charges.

Views of the Board

280. The Board notes the concerns raised by YECL and the interveners, and the concerns expressed by the Board in the DCF section of this decision.

281. As the Board has requested YEC to file a revised DCF and to address the concerns raised by the Board in that filing, the Board directs YEC to refile a Rate Schedule 42 in cooperation with YECL as directed in Section 3.6.2 of this decision.

5 Capital projects

5.1 Capital projects

282. The largest component of YEC's rate base is investment in capital works [property, plant and equipment (PP&E)], planning and study (feasibility) costs, and relicensing costs. YEC submitted that forecast capital spending aligns with load growth and the need to re-invest in existing infrastructure.

283. YEC also submitted that it has had record levels of capital spending since 2009. Major legacy initiatives have been carried out to connect the WAF and MD grids, and to enhance renewable hydro capability on the new integrated system.[177] Coordinated with these initiatives, projects were completed to enhance safety and reliability. Moreover,

[177] Three major projects have been completed – the CSTP Stage 2, the Aishihik Third Turbine and Mayo B.

deferred cost expenditures have increased with respect to assessing DSM planning, updating the 2006 resource plan, and identifying and examining potential new near-term generation development options, renewable and other, to displace costly diesel generation that would otherwise be required to meet load growth after 2013.[178]

284. YEC submitted that the Application includes, for Board approval, several policies relating to deferring capital expenditures, including YEC's planning cost account policy (Appendix 5.1) and its DSM accounting policy (Appendix 5.2), which are reviewed in other parts of this decision.

285. CW noted that 2011 year-end property plant and equipment and net rate base in the regulatory filings differ from those set out in the Application. CW therefore submitted that YEC be directed to correct its 2012 opening Plant balances to the actual balances recorded in the regulatory filings. Furthermore, the Board should direct YEC in its compliance filing to provide a reconciliation of forecast plant balances, as applied for, to the actual, explaining any differences between forecast and actual.[179] CW added that the Board is entitled to use the best information available at the time of its decision.

286. This following section reviews:

a. major projects (projects greater than $1 million) undertaken by YEC since the 2008-09 GRA and those projects planned for the 2012 and 2013 test years

b. ongoing capital projects costing between $100,000 and $1 million that are forecast to occur over the 2012 to 2013 test period

5.1.1 Major projects over $1 million

287. YEC submitted that a significant investment in new and existing infrastructure has been undertaken since 2009. The current Application indicates an approximate $32.05-million growth in mid-year net rate base from 2009 approved to 2011 preliminary actual. This is significantly lower than the growth in gross rate base over the same period of approximately $213 million. Three major projects — Mayo B, CSTP Stage 2 and Aishihik Third Turbine — which included $128.5 million of third party contributions, have reduced the overall impact on ratepayers.

288. YEC forecast mid-year net rate base growth of approximately $61.7 million over the test period and provided the following major projects for review:

- Major near-term projects subject to prior major Board process review – contributed to a net rate base increase of approximately $43.8 million compared to approximately $172.3 million capital costs for projects in service prior to December 31, 2011:
  - Carmacks-Stewart Transmission Line Stage 2 project – project costs of approximately $42.9 million are forecast to be offset entirely by federal and YDC contributions.

[178] Application, page 5-1 to 5-2.
[179] CW final argument, paragraph 12.

- Mayo hydro enhancement project (Mayo B) project – project costs of approximately $116.6 are forecast to be offset by federal and YDC contributions of $81.6 million leading to net rate base cost forecast of $35 million.
- Aishihik Third Turbine construction project – net rate base cost forecast of $8.8 million net of $5 million Government of Yukon contribution.

- Major projects required to ensure system safety and reliability – net rate base increase of approximately $19.1 million:
  - Mayo Hydro substation enhancements project – forecast cost of $10.15 million; project is to be completed in 2012.
  - Mayo head gate repairs project – forecast cost of $1.3 million; project is to be completed in 2012.
  - Aishihik generation station redundancy project – forecast cost of $6.4 million; project completion in 2011.
  - Whitehorse spillway improvements project – forecast cost of $1.25 million.

- Other major projects not related to mine grid connections – net rate base increase of $3.2 million:
  - Enterprise system (JDE) – forecast cost of $3.2 million, including JDE and enterprise system enhancement projects, to be completed in 2013.
  - Whistle Bend subdivision supply – forecast total spending of $5.23 million in 2013; this project will not be in service before 2014 and therefore will not impact rates in the test years.

- Mine grid connections to be offset by customer contributions – no net rate base cost impact; all capital costs offset by customer contributions:
  - Victoria Gold grid connection project.
  - Western Copper grid connection project.

5.1.1.1 Major projects other than Aishihik generation station redundancy project

289. CW noted that spending on the Mayo B project continued into 2012. As the project has not been completed, CW recommended that the Board direct "… that Mayo B be removed from the 2012 opening plant balances and placed in [Plant Held For Future Use] PHFFU until the project is complete and accepted for service."[180]

290. LE submitted that, in its view, YEC undertook too many projects and studies in a very short time, which led to greater capital expenditures than was necessary. Further, YEC "… provides insufficient detail to be able to be very specific on …" the projects … "but the cost overruns on the Aishihik third turbine project are indicative of what was happening."[181] LE recommended that the Board approve adding the Mayo B hydro project, the Aishihik third turbine and the Carmacks-Stewarts Crossing transmission line Phase 2 into rate base. With respect to system safety and reliability projects, LE recommended approval of the Mayo head gate and Whitehorse Rapids spill projects. Furthermore, "Subject to any comments on costs by other parties on the Aishihik

[180] CW final argument, paragraph 15.
[181] LE final argument, section 19.

redundancy and Mayo substation enhancement projects,…"[182] LE recommended that the Board approve these projects. Lastly, LE recommended that the Board approve the replacement of the JDE system with the proposed Microsoft Dynamics GP system.

291. UCG submitted that the Carmacks-Stewart transmission – Stage 2, the Mayo hydro enhancement, and the Aishihik Third Turbine projects should not be allowed into rate base until the final costs are determined and the impact on ratepayers is determined.[183] Moreover, UCG submitted that YEC "…should be directed to recommend to the Minister that all capital projects costing in excess of $1 million dollars should be reviewed per Part 3 of the *Public Utilities Act* and that YEC should be proactive in its efforts to have major capital projects reviewed by the YUB in advance of construction."[184]

292. UCG submitted that none of the Mayo-related projects should be added to rate base until a full review can be made to ascertain the benefits accrued to ratepayers and the prudency of the expenditures.[185] With respect to the Aishihik Third Turbine project, UCG pointed to YEC's confirmation that doubling of the project costs was primarily due to inadequate project costing on the part of AECOM and significant errors in AECOM's cost estimates. Accordingly, UCG submitted that the extra costs arising out of AECOM should not be recovered from ratepayers.

293. With respect to other Aishihik related projects, including the Aishihik generation station redundancy project ($6.4 million), UCG noted that YEC did not provide any information related to cost/benefit available on the projects. UCG therefore submitted that none of the Aishihik-related projects listed in Table 5.2 of the Application should be added to rate base until a full review can be made.[186]

294. Respecting the other major projects category, UCG submitted that without details of the Enterprise business system replacement project, it is not possible to determine the prudency of the related expenditures.[187] UCG further submitted that the forecast Whistle Bend subdivision, Whitehorse spillway Western Copper Grid connection expenditures, require a significant amount of additional review prior to being approved as part of YEC's capital project.[188] Western Copper should be directly charged $30,233 in deferred costs related to the transmission line to its facilities, since it is the only ratepayer gaining benefit from the expense.[189]

295. YCS submitted that the Board should not allow $35 million for the Mayo B project to be added to rate base.[190]

182 LE final argument, section 23.
183 UCG final argument, paragraphs 75, 76 and 77.
184 UCG final argument, paragraph 82.
185 UCG final argument, paragraph 121.
186 UCG final argument, paragraphs 127 to 130.
187 UCG final argument, paragraph 133.
188 UCG final argument, paragraphs 137, 141 and 143.
189 UCG final argument, paragraph 144.
190 YCS final argument, page 5.

296. YEC submitted that the "…relevant test (for determining when project costs go into rate base) is when the project went into service to yield benefits to ratepayers – and this test was met prior to the end of 2011."[191] Furthermore, it is normal on large projects, such as Mayo B, for some expenditure to occur after the project goes into service to address deficiencies. The plant has been operated at full capacity since the in-service date in December 2011. Similarly, the Aishihik Third Turbine and CSTP Stage 2 projects went into service in 2011.[192]

Views of the Board

297. In making a determination, the Board considers whether a project is used and useful. The Board notes that the Mayo B and CSTP Stage 2 projects went into service prior to the end of 2011, and as such, are providing benefits to Yukon ratepayers. The Board further notes that CSTP Stage 2 project costs are fully funded by the federal and Yukon government contributions and as a result there is no impact on rates.[193] With respect to Mayo B, the Board notes that the $35 million net rate base cost after Yukon and federal government contributions is approximately the amount forecast. The Board further notes that flexible debt long-term financing has been secured by YEC from YDC to mitigate ratepayer risks related to costs exceeding 11 cents per kWh (2012$) in any year for diesel generation displaced.[194].

298. Notwithstanding, the final estimated cost of $13.8 million is significantly higher than original project estimates on the order of $8.5 million, the Board, after reviewing CW-YEC-1-28, considers that Yukon ratepayers received a net benefit from the Aishihik Third Turbine construction project and that this project is used and useful. The Board agrees with YEC that this project will provide a net economic benefit to Yukon ratepayers over the project's economic life based on the expected displacement of diesel generation. Further, the Board agrees that the costs associated with this project were prudently incurred and were necessary in order to complete the project.

299. Considering the above, the Board approves the capitalization of Mayo B, CSTP Stage 2 and Aishihik Third Turbine project costs as described in the preceding paragraphs.

300. The Board notes that interveners raised concerns respecting projects which were undertaken for safety and reliability reasons. The Board finds that costs associated with the majority of these projects, i.e. Mayo hydro substation enhancements, Mayo head gate repairs and the Whitehorse spillway improvements projects to be prudent and that the projects associated with the these assets are used and useful. The Board approves the capitalization of these projects.

301. Respecting UCG's concern with the inclusion of Western Copper aerial mapping and route-selection charges, the Board notes YEC's acknowledgement that Western Copper aerial mapping and route-selection expenses should have been held in work in progress (WIP). The Board directs YEC in its compliance filing to move the aerial photo

[191] YEC reply argument, page 53.
[192] YEC reply argument, page 53.
[193] Application, page 5-5.
[194] Application, page 5-6.

mapping and route-selection charges ($30,233) related to the Western Copper grid connection project into WIP to be charged later to Western Copper.

302. Respecting Enterprise system costs, the Board has reviewed the record and finds the costs to be reasonable. The Board therefore approves project costs related to the Enterprise system, including the JDE and enterprise system enhancement projects to be completed in 2013.

5.1.1.2 Aishihik generation station redundancy project

303. This project was undertaken to rectify a system reliability issue relating to redundancy identified as a result of a major system outage on January 29, 2006. The cause of the extended outage was that the main power cables connecting the generation to the transmission system failed. YEC submitted that this became a top priority for the Company. The project provides for redundant electrical supply to the main power transformers and improves the protection for each transformer.[195] The Aishihik redundancy project was considered substantially complete at the end of 2011 and transferred to rate base at that time.[196]

304. The project justification was provided to the YEC Board in August 2009; the preliminary budget estimate was $2.9 million.[197] Subsequent to the 2006 major system outage, YEC sent a letter to the Board, dated April 14, 2006 (letter), wherein YEC submitted that "[respecting] the likelihood for the event recurring, … conditions currently applicable on WAF … will almost always cause a grid blackout … The probability of an unplanned loss of any one such hydro generating unit is assessed in system capacity planning studies, and (as demonstrated by system experience) is very low."[198] Furthermore, YEC submitted that it had recently adopted revised capacity planning criteria which had noted the need to address Aishihik-related transmission connection reliability.

305. YEC submitted that:

> … specific vulnerabilities of the Aishihik plant which led to the January 29th emergency are also addressed in this appendix and the installation of a redundant cabling system from the underground powerhouse to the surface substation has been advanced **from 2009 to 2007.** The existing 7 cables remaining in the plant are being replaced before the end of June this year with 9 new cables.[199]

306. Original budget cost estimates set out in the following table, were not based on tendered costs. Subsequent to the tender process in February 2010, the tender was cancelled and AECOM and YEC held discussions with contractors to refine the project scope and achieve lower costs. However, the discussions did not materially alter the estimated project costs. A decision was made to proceed with the project based on tendered costs of August 2010. YEC submitted that an additional $0.257 million is

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195 Application, Section 5.2.1.6 page 5-14 to page 5-16.
196 UCG-YEC-1-50 (f) and (h).
197 CW-YEC-1-30 (a) and (b).
198 YEC letter to YUB, April 14, 2006, pages 3 and 4.
199 YEC letter to YUB, April 14, 2006, page 6.

forecast for 2012 to address project wrap-up activities and outstanding items such as gauges, performance testing, minor deficiencies' corrections, and other matters. The additional costs lead to a $6.365 million final cost estimate in this Application.[200]

Table 17. **Aishihik redundancy project estimates**

Estimates	Date	Amount
Original Budget	April 2009	$2,903,350
Construction Approval	August 2010	$4,579,625
Final Cost Estimate	2012-13 GRA	$6,107,887

Source: CW-YEC-1-30 (a) and (b), Table 1.

307. YEC stated that issues with the Aishihik redundancy project relate to cost estimating, i.e. the estimates provided by AECOM did not accurately reflect the costs to do the work.

308. LE suggested that it would have been appropriate for a Board review of the Aishihik generating station redundancy project. Furthermore, an Aishihik redundancy project of some sort made "… far more sense than twinning the power line ..."[201] Accordingly, LE recommended that the Board approve the Aishihik redundancy project subject to any comments on costs by other parties.

309. UCG submitted that YEC did not provide any information related to cost/benefit analysis available with respect to any of the Aishihik projects. UCG submitted that none of the Aishihik-related projects, including the Aishihik redundancy project, should be added to rate base until a full review can be made "…not only what the projects entail, but also what benefit ratepayers will realize from these expenditures and how the money was spent in lieu of alternatives available."[202]

Views of the Board

310. Although there is no formal policy, the Board notes YEC's commitment, on a best- efforts basis, to seek Board review prior to construction of new capital projects costing $3 million or more. Further, absent a review of capital projects through either a:

a. Government direction under Sections 17 or 18 of the Act, or
b. A review under Part 3 of the Act,

the only means available for YEC to initiate a review of a capital project is through a GRA.[203]

311. The Board notes that the letter to the Board was dated April 11, 2006, and YEC's 2008-2009 GRA is dated September 2008. Furthermore, YEC in its letter, submitted that "… the installation of a redundant cabling system from the underground powerhouse to the surface substation has **been advanced from 2009 to 2007.** The

200 CW-YEC-1-30 (a) and (b).
201 LE final argument, Section 23.
202 UCG final argument, paragraphs 128 to 130.
203 LE-YEC-1-18 (a) and (b).

existing 7 cables remaining in the plant are being replaced before the end of June this year with 9 new cables."[204] [highlight added]

312. The Board observes that YEC had advance notice of the project well before its 2008 – 2009 GRA, and well before they hired AECOM. However, YEC did not submit it as a project at that time, giving notice to the Board by way of an information response with no formal reference to a project per se. Moreover, the Board notes that the project has expanded from one of merely replacing redundant cable. The project "…improves the protection for each transformer … [D]esign required a new 7 unit switchgear lineup … a second run of cables was installed … a new switch around power transformer … new switch around power transformer T1… bushing on transformer T3 … PT transformer and a set of reactor cables …"[205] "… [Further] it was decided to install the building at the same level as the substation …"[206]

313. The Board has concerns with the escalation of costs, but the Board notes that additional projects were undertaken at the time when the redundant cabling system was replaced. The Board has reviewed the project costs and has not seen any evidence that the additions to the project were unnecessary or not useful. Therefore, the Board approves the project costs as filed. However, in future, the Board directs YEC to provide business cases for all projects, including reliability projects, greater than $1 million. These business cases are to include alternatives to the recommended projects as well as the economic impact to ratepayers of the recommended projects.

5.1.1.3 Capital projects – specific impacts on YECL

314. YEC acknowledges that it includes diesel generation and other associated cost requirements in its capital project budgets. YEC further submitted that costs related to expected Aishihik plant shutdowns were included in budgeted amounts for the Aishihik Third Turbine project. YEC stated that it had received YECL invoices that requested reimbursement of costs for impacts related to YEC's Haines Junction bypass and CSTP projects. YEC added that it was not aware of any formal request for compensation prior to the commencement of these projects. In summary, YEC submitted that there were no grounds for payment of these claims as the invoices were received after the project budgets had been set.[207] Also, these costs should be justified by YECL before the Board and should be included in YECL's revenue requirements. YECL replied these were planned outages and as a supplier of electricity in Yukon, YEC "cannot simply abandon its obligations for maintaining supply during extended planned outages that it causes.[208].

315. YEC disagreed with YECL and voiced concerns regarding the feasibility of each utility charging the other for such costs. YEC submitted that if the Board sees merit in ensuring that such costs be recovered, the Board should direct YECL to set up a deferral account in order to test the costs.[209]

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[204] YEC letter to YUB, April 14, 2006, page 6.
[205] Application, page 5-15.
[206] CW-YEC-1-30.
[207] YECL-YEC-1-27.
[208] YECL final argument, paragraph 23.
[209] YEC reply argument, page 55.

Views of the Board

316. The Board notes that the invoices relate to a YEC planned outage in respect of one of its major projects. As part of YEC's feasibility study work leading up to the decision, whether or not the project is given the go-ahead, the Board considers that YEC would investigate and determine all costs that relate to such projects. The Board finds that it is YEC's obligation to forecast all future costs, including all third party costs, such as YECL utility costs that relate to YEC's proposed capital projects. The Board directs YEC to consult with YECL to determine costs that are to be incurred by YECL as a result of YEC's proposed capital project costs. The Board further directs YEC to include such costs in future GRAs for Board and intervener review.

5.1.2 Projects between $100,000 and $1 million

317. YEC submitted that significant re-investment in existing infrastructure has been undertaken since 2009 to ensure that the Yukon integrated grid can continue to meet the level of growth on the system in a safe and reliable manner. Total spending for projects less than $1 million on property, plant and equipment (PP&E) has averaged $7.9 million over the period from 2009 to 2011.

318. YEC also submitted that ongoing capital works spending on PP&E to be added to rate base is forecast at $5.426 million for 2012 and $7.107 million for 2012 .The projects include:

- Generation projects ($2.416 million in 2012 and $3.012 million in 2013) – YEC stated that spending on generation projects is focused on reliability improvements to upgrade or replace deteriorated infrastructure required for continued safe and reliable operation of the existing hydro and diesel plants and on business improvements to enhance operation of the generation plant through upgrade or replacement of deteriorated infrastructure. Key areas of spending are:
  - Hydro plant – improvements undertaken at all hydro facilities to include installation of a) new oil filtration systems on the hydro governor to reduce wear and tear, b) hydro unit platforms for working in draft tubes to provide a safe working surface, and c) dam water barriers to ensure public safety:
    - Wareham dam – to upgrade of spillway gates
    - Mayo Hydro plant – to install jackscrews on spill gates to ensure reliable operation
    - Aishihik – icing studies and mitigation work to address effects of Aishihik operation on infrastructure downstream
    - Whitehorse – to replace deteriorated gear boxes, rebuild of the P 125 rack and trash rack heating system that is at end of life, and refurbishment of end of life commutator at WH1 and WH2
- Diesel plant

  - Faro – extensive improvements to either replace damaged equipment or modernize and upgrade existing equipment to ensure units can be run more efficiently to provide reliable backup generation on the integrated grid, and to allow for load sharing and remote control capability
  - Whitehorse – to replace of fuel tank and base at the plant to avoid potential failure and improve storage capacity
  - Mayo – SCADA connection to allow for remote control of generation
- Transmission – forecast expenditures in the test years is focused almost exclusively on reliability as well as ongoing transmission pole test and treatment program. Moreover, a review of all substation protection and control systems is being undertaken to ensure a consistent standard is applied for continued operations.
- Distribution – test-year expenditures include no routine spending. YEC submitted that $0.47 million (with $0.4 million customer contributions) are required each year of the test period to meet continued service requirements. Distribution projects include the Faro mine connections (for the site abandonment plan, with costs expected to be offset by customer contributions), a new three-phase distribution line at Dawson Dome, and ongoing work to secure easements for distribution lines and requirements for new customer extensions.
- General plant and equipment (GP&E) projects ($1.043 – test-year spending will focus on business improvements with $0.465 and $1.2635 forecast to be spent in 2012 and 2013 respectively. Projects to be undertaken in the test years include improvements at the Lewes Control structure to upgrade the fish ladder and boat lock which are at end of life, and installation of a repeater in the Tintina trench area to improve communications for YEC staff. Other business improvements include an interactive safety and environmental video and online orientation and compliance process, a disaster recovery plan and business continuity development plan, electronic document management system, network improvements, security risk management and vehicle purchases. Safety improvements include installation of fall restraint or arrest systems for all facilities.

319. Other than the Mayo diesel plant project, interveners did not take issue with the YEC's proposed capital projects between $100,000 and $1 million.

320. Noting that YEC did not purchase the Minto diesels, LE requested YEC to explain why expenditures related to this project should be included in rate base. YEC explained that the original plan was to purchase these units for YEC dispatch, and as such, SCADA control was mandatory. However, as the Minto mine negotiations continued, the decision was made not to purchase the units, leaving Minto ownership and control of the units. Notwithstanding this decision, YEC decided to continue proceeding with SCADA as its implementation was mostly complete and it would provide YEC with the ability to monitor these units. With this ability, YEC submitted that it could access the necessary information to ensure that the units are operated in a

manner that maximizes overall coordination and grid reliability, and to ensure they do not adversely affect the operation of the YEC electrical grid.[210]

321. LE submitted that since the Minto diesels were not purchased by YEC, it was imprudent to spend $490,000 on improvements to these generators and SCADA for them. Accordingly, LE recommended that the Board disallow the $490,000 expenditure. LE also recommended that considering the impact that capital expenditures are having on rates, the Board order YEC to limit spending on projects between $100,000 and $1 million to $5 million in each of 2012 and 2013.[211]

322. YEC submitted that there is no basis for LE's recommended $5-million cap for each test year. Furthermore, with regard to the Minto diesel SCADA project, YEC submitted that this project is a prudent expenditure that provides benefits to the system and to ratepayers, and should be included in rate base. YEC submitted that its operational staff indicated that there is a benefit in that "Operationally it's easier for us to bring [the diesel units] on to the system if we can see what their diesels are doing."[212]

Views of the Board

323. The Board notes that the determination to continue with SCADA control of the Minto units was made at the time the decision to purchase the units was made, and SCADA implementation was mostly complete when YEC decided not to proceed with the purchase. The Board is of the view, that although it may be operationally easier for YEC to bring the units on-line if it is able to monitor the units, no cost/benefit analysis supports that conclusion. Further, the Board notes that acquisition of the Minto diesels was not approved as part of the Minto power purchase agreement and that the Minto diesels have not been given approval as part of YEC's rate base. From the evidence on the record, the Board understands that SCADA control is not mandatory on the Minto mine generating units as these units are not owned by YEC.

324. The Board does acknowledge YEC's submission that "… there would be benefit to [us] having visibility into these diesels in instances where we have outages and we're trying to bring them [Minto] back onto the grid."[213] Again, YEC has not demonstrated or quantified what the benefit to ratepayers would be. Therefore, the Board directs YEC in its compliance filing to remove all Minto-related SCADA costs from rate base.

325. LE has not persuaded the Board that spending on capital projects in the range of $100,000 to $1 million should be limited to $5 million. The Board does not approve LE's recommendation to limit projects between $100,000 and $1 million, to $5 million per year of the 2012-13 test period.

5.1.3 Deferred costs

326. This section reviews deferred projects undertaken by YEC since the 2009 GRA, with particular focus on the 2012-13 test period. Deferred costs during the 2009-2013

[210] LE-YEC-1-28.
[211] LE final argument, section 25.
[212] YEC reply argument, page 57.
[213] YEC reply argument, page 57.

period reflect YEC's work to identify and examine potential near-term renewable and other generation development options to displace future diesel generation that would otherwise be required to meet load growth.

327. Deferred costs include activities to examine major new generation options (feasibility studies), continued relicensing on the Mayo Lake Storage Enhancement Project (Mayo Lake Relicensing), rate case work on DSM and the update to the 2006 resource plan. Ongoing deferred-cost activities are also included to address other rate case, relicensing, deferred overhauls and feasibility studies.

328. With respect to deferred costs, YEC included two policies for Board approval:

(a) planning cost accounting policy (PCAP) – due to the unprecedented levels of planning costs YEC incurred since 2009, YEC proposed a PCAP to ensure that planning costs are addressed and included in rates in a manner that address rate shock for ratepayers, and
(b) demand-side management policy.

These policies are discussed below in other sections of this decision.

5.1.3.1 Major projects over $1 million

329. YEC submitted that it must continue to plan to meet potential future loads, both near term and the longer term, in a cost-effective manner that ensures continued reliable and low-cost supply that is also environmentally responsible:

> In this respect, Yukon Energy cannot wait until loads develop with full certainty before commencing the required planning and studies work to develop new sources of supply, but must advance such work to ensure projects can be developed on timelines sufficient to meet new loads or are "shelf ready" (i.e., planning and studies work completed and licences obtained) such that a final decision to proceed can be made and construction commence when new loads are committed.[214]

330. To ensure there is sufficient generation and transmission capability to meet growing power requirements on the integrated grid without relying only on high-cost diesel generation, YEC has carried out extensive feasibility and planning work to assess potential options for reducing diesel generation that would otherwise be required to supply future load growth. The nine major deferred-cost projects, excluding 2012-13 GRA rate case deferred costs, undertaken by Yukon Energy since 2009, have total projected costs of approximately $23.91 million to the end of 2013, with projected third party contributions offsetting $1.48 million of these costs.

331. YEC submitted that progression through the planning process on each major deferred-cost project has been carefully monitored and controlled by staged approvals for expenditures that apply to each project phase. In effect, each phase requires an approval to define the scope of work and the deliverable to be completed before progressing to the next stage. During the planning phase, ongoing assessment may determine that a project is not economical based on current conditions. In the event that a project is deemed uneconomic at the end of a planning phase, work would be delayed

[214] Application, page 5-26.

until suitable conditions arise and the project is considered economically feasible. If and when a project successfully progresses through the planning and feasibility phase and procures necessary regulatory approvals, it will advance (where appropriate, and subject to final tenders and other required approvals) to the construction stage. The following table summarizes the expenditures related to YEC's proposed major deferred-cost projects in this Application.

Table 18. **Major deferred-cost projects – total project costs net of contributions ($ million)**

Project	Year-end 2011	2012 Forecast	2013 Forecast	Totals
Hydro enhancements				
Marsh Lake storage	$3.23	$ 0.800	$ 0.800	4.83
Gladstone diversion	3.69	0.200	0.500	4.39
Atlin Lake Storage	2.23			2.23
Mayo Lake enhanced storage	1.46	0.660		2.12
Subtotals	10.61	1.66	1.30	$13.57
Near-term generation options				
Demand-side management (DSM)	0.302	1.074	1.635	3.01
Waste-to-energy/Biomass	0.628	0.500	0.500	1.63
District Heating	(0.460)	0.460	0.500	0.50
Liquefied natural gas (LNG)	0.169	1.500	1.000	2.67
Subtotals	0.639	3.534	3.635	7.81
Long-term generation options				
Geothermal	1.950	0.386	0.300	2.64
Subtotals	1.950	0.386	0.300	2.64
TOTALS	**13.199**	**5.58**	**5.235**	**23.91**

Sourced from YEC Application, pages 5-30 to 5-47

332. Each major deferred-cost project is discussed below.

Marsh Lake Storage ($4.8 million)

333. YEC submitted that the Marsh Lake Storage project was a means of enhancing winter capacity and energy available to the Whitehorse Rapids generating station to displace higher-cost diesel generation that would otherwise be required. The Marsh Lake Storage project includes capital improvements to the Lewes Lake control structure and an amendment to YEC's water licence to hold back up to an additional 0.3 meters of water in Marsh Lake in the fall and withdraw the water over the winter period. YEC proposed that of the total $4.83-million project costs at the end of 2012, $4.03 million should be capitalized and amortized over 10 years.

334. YEC submitted that spending in 2012 and 2013 is expected to relate to completion of baseline work, effects assessment and mitigation design and preparation and filing of the Yukon Environmental and Socio-economic Assessment Board (YESAB) submission. The 2013 budget will cover the YESAB review process and water licence amendment hearing process. Nonetheless, YEC submitted a decision had to be made whether or not to proceed with the project by the end of 2012. Forecast costs to complete the work is estimated at $10.5 million; mitigation design comprises about half

of the total cost, albeit YEC submitted that mitigation actual costs cannot be known with any certainty.

335. LE submitted that this project remains viable and recommended that it remain as work in progress.[215]

336. UCG submitted that the lack of an independent view on Marsh Lake and hydroelectric resources in general tainted some of the costs related to this project. Given the total costs of this capital project, UCG submitted that these deferred costs should not be capitalized until the Marsh Lake Storage project is placed into service and the costs incurred have undergone a thorough prudence review.[216]

Views of the Board

337. The Board finds that Marsh Lake Storage is currently a viable project, and as such, all Marsh Lake-related project costs are to be held in WIP, until the project is completed. Furthermore, YEC is to cease work on this project if and when YEC concludes that there is no net economic benefit of the project to ratepayers.

Gladstone hydro enhancement project ($4.4 million)

338. YEC submitted that this project was a cost-effective means of increasing the amount of water available in winter months for hydroelectric generation at the Aishihik hydro facility in order to displace higher-cost diesel generation that would otherwise be required. The project proposes to divert water from the headwaters of Gladstone Creek into the Aishihik Lake system, thus increasing the amount of water available at the Aishihik hydroelectric generation facility. Assessment and permitting is required under both the Yukon and federal regimes. Moreover, First Nations have interests in the vicinity of the project.

339. Planning and feasibility costs to the end of 2011 are $3.694 million with forecast spending over the test years of $0.7 million. YEC submitted that third party environment assessment, engineering and project management costs comprise 90 percent of the project costs to date. Earliest potential in-service for this project has been estimated to be late 2017.

340. YEC submitted that risk and uncertainties respecting this project relate to regulatory risks and the need to resolve arrangements with the First Nation groups. As a result, 2012 activities are directed at addressing and resolving these risks, and future expenditures beyond 2012 will be dependent on the success of these activities.

341. YEC submitted that forecast feasibility study costs to the end of 2012 of approximately $3.9 million are assumed to be closed at the end of 2012 and should be amortized over 20 years starting in 2013. Furthermore, 2012 feasibility study costs of $0.5 million are to be amortized starting in 2014.

[215] LE final argument, section 26.
[216] UCG final argument, paragraph 105.

342. LE noted that this project has the potential to provide very valuable winter energy to the system. Subject to an agreement with the affected First Nations, LE submitted that this project should remain as work in progress. Notwithstanding, LE suggested that YEC should have solicited more specific support for this project prior to spending the large amount of monies. That being said, if the project does not move forward because of First Nation opposition, a portion of this expenditure should be disallowed.[217]

343. UCG submitted that the study costs for the Gladstone Diversion project are not "used and useful" in the normal way that rate base assets must be to attract a return on investment. UCG therefore submitted that no utility property shall be deemed used and useful until it is providing actual utility service to customers.[218]

Views of the Board

344. The Board finds that this project has potential to be viable and directs that all project expenditures be held in WIP until the project is completed. Moreover, YEC is to cease work on this project if and when YEC concludes that there is no net economic benefit of the project to ratepayers.

Atlin Lake Storage ($2.2 million)

345. YEC submitted that this hydro enhancement project was examined as a cost-effective means of enhancing winter capacity and energy available to the Whitehorse Rapids generation station in order to displace higher-cost diesel generation that would otherwise be required.

346. The current estimate is that an additional nine GW.h/year of added hydro energy could be generated at Whitehorse with regulation of Atlin Lake outflows within natural range of lake levels. However, the control structure would need to be located entirely within British Columbia. The inter-jurisdictional nature of the project and interventions by local residents presented challenges in respect of proceeding with the project, especially when the BC government designated Atlin River as a Class A park. While it had previously supported the project, YEC made the decision to discontinue work on the Atlin storage project. Accordingly, YEC proposed that the feasibility study costs to date totalling $2.2 million be amortized over 10 years starting in 2012.

347. LE acknowledged that opposition to this project has always been intense and submitted that the monies should not have been spent until the possibility of developing the project was clear. LE stated that YEC was imprudent respecting project expenditures and submitted that $1.2 million in project costs should be disallowed and the remainder handled as proposed.[219]

348. UCG submitted that the study costs for the Atlin Lake storage project are not used and useful rate base assets and should not attract a return on investment. UCG

[217] LE final argument, section 26.
[218] UCG final argument, paragraph 113.
[219] LE final argument, section 26.

submitted that no utility property shall be deemed used and useful until it is providing actual utility service to customers.

349. YEC submitted that LE's proposed $1.2-million disallowance lacks any evidence regarding specific imprudent costs that the Board and YEC can address. YEC submitted that expenditures were prudently incurred and YEC immediately ceased work on the project once it was clear that the new park designation would prevent this project from proceeding.[220]

Views of the Board

350. Having reviewed the evidence on the record, the Board finds the Atlin Lake study costs to be prudent because it had the potential to add nine GW.h/year of hydro energy which could be generated at Whitehorse, with regulation of Atlin Lake outflows within natural range of lake levels. Also, the study was terminated once the park designation issued. As a result, the Board approves the costs as proposed.

Mayo Lake Enhanced Storage ($2.1 million)

351. This hydro enhancement relicensing project will amend the current Mayo Generation Station Water Use Licence to provide for up to an additional one metre of draw down that will increase renewable power generation capability of the Mayo hydro facility and displace diesel generation that would otherwise be required. The project was originally included as a component of the Mayo hydro enhancement project (Mayo B) but was subsequently withdrawn.

352. YEC submitted that the project will require *Fisheries Act* authorization, but will not require physical works for water storage beyond those already in service for the existing Mayo generation plant. Furthermore, a project proposal was being prepared and was expected to be filed with YESAB in 2012. YEC estimated that permitting and licensing costs to the end of 2013 would total $2.1 million, with forecast spending in the test years to be $0.66 million. In the event that the project is approved, these costs are assumed to be amortized over the remaining term of the Mayo licence (13 years).

353. Noting the working relationship between YEC and the First Nation of Na-cho Nyak Dun and the benefits to the grid because of winter energy at the Mayo hydro plants, LE submitted that this project should remain as work in progress and be amortized as YEC proposes when it is completed.[221]

Views of the Board

354. The Board has reviewed the project and notes that the amended water use licence will result in increased renewable power generation capability, at the same time requiring no physical works. Furthermore, the costs are to be amortized over the term of the Mayo generation facility water use licence. Accordingly, the Board approves the project as proposed in the Application.

[220] YEC reply argument, page 61.
[221] LE final argument, section 26.

Demand-side management (DSM) – ($3.012 million – net of contributions)

355. YEC submitted that DSM is widely recognized in utility resource planning to be feasible at relatively low cost for ongoing implementation with non-industrial and industrial customers. The Board directed that YEC and YECL consult with stakeholders to jointly develop a DSM policy paper (plan) to be presented as part of the next GRA.

356. YEC stated that a significant amount of DSM-related planning and consultation work has been undertaken by it alone and in coordination with the Yukon government (YG), YDC and YECL to implement a robust and aggressive DSM/SSE[222] program in order to meet the Board directive:

- YEC continues to lead the joint working group (YECL and YG)
- YEC in co-operation with YECL and YG proceeded with a detailed conservation potential review study that forms the basis of the DSM plan that is to be prepared after the fall of 2012
- work in 2011 also included the development and implementation of several pilot programs and the continued engagement of the public to develop the DSM plan[223]

357. YEC submitted that it is considering DSM programming as part of its resource planning work and as a key supply option to help address near-term and long-term energy requirements. To that end, YEC:

- has undertaken and continues to review the programs offered in other jurisdictions
- consulted extensively on DSM and included it as a supply option for review and discussion during the March 2011 Energy Charette
- as part of its resource planning processes, continued with baseline research and pilot projects. Pilot projects undertaken or currently underway include:
  (a) a LED streetlight project
  (b) an energy audit of Alexco mine
  (c) basic energy-management training
  (d) an education event for children
  (e) an on-line energy calculator
  (f) public education, and
  (g) an energy audit of YEC's own buildings.[224]

358. Planning and feasibility with regard to DSM to the end of 2011 total $1.037 million; however, with offsetting contributions,[225] net 2011 costs are $0.303 million. Forecast spending over the test years is $2.709 million. YEC submitted that a material portion of DSM costs incurred to date and expected to be incurred in the test years relate to internal DSM within YEC, including feasibility, study, planning and implementation of conservation improvements at YEC's existing building and facilities. It stated:

[222] Application, page 5.3-2; DSM/SSE demand-side management/supply side enhancement.
[223] Application, pages 5-39 and 5-40.
[224] Application, page 5-40.
[225] Contribution consist of $0.5 million from YDC, $0.09 million form YG, and $0.145 from YECL.

> In 2011, Yukon Energy retained a third party consultant to conduct an energy audit of 25 of its buildings to determine significant areas where energy reductions could be made (of this, 6 were selected based on ease of access and opportunities for savings). Specific internal DSM activities will be undertaken in the test years and may include lighting upgrades, upgrades to building envelope and replacement of fixed pumps with variable speed pumps. The benefit of this form of DSM is that since Yukon Energy is carrying out the changes there is assurance that the activities will be undertaken and targeted savings achieved.

359. Pursuant to YEC's proposed DSM accounting policy, YEC stated that DSM costs will be closed and amortized each year over a 10-year period.

360. CW submitted that DSM is in its infancy stage in the Yukon and should be treated in a manner similar to deferred study costs.[226] LE submitted that DSM and supply-side efficiencies are very important initiatives. Moreover, LE is of the view that the utilities and the Yukon government have spent more money on DSM than necessary. However, it added that this initiative is too important to not push forward. LE recommended that the Board direct that the DSM expenditures be amortized as proposed by YEC.[227]

361. UCG noted that YEC has not submitted a policy paper with respect to DSM initiatives. Further, despite the lack of a DSM policy paper, YEC has created an Energy Conservation Department to work with stakeholders on Yukon-wide energy conservation programs and also focus on YEC's DSM programs. UCG submitted that the Board, before approving a YEC DSM policy, should direct YEC to identify all DSM-related costs it has incurred. UCG also submitted the YEC should be directed to indicate where in its 2012 and 2013 proposed revenue requirement the net benefits of DSM are stated. Respecting the Alexco energy audit costs, UCG submitted that the costs should be absorbed by Alexco or YEC's shareholder and costs should be collected equitably from those receiving the benefits.[228]

362. YEC submitted that UCG's assertions that YEC should wait for approval of a policy, or that the Board cannot approve costs without a cost/benefit assessment, ignores the evidence.

363. YCS acknowledged the perverse economics regarding DSM: "… it results in the public utility spending money to make less money if the diesel savings are less than project costs."[229] YCS submitted that DSM would be more appropriately carried out by the Energy Solutions Centre and funded by taxpayer dollars, not the ratepayers. Moreover, YEC should focus its DSM initiatives toward load management to reduce diesel generation and maximize renewable energy.[230]

Views of the Board

364. In Decision 2009-08, the Board set out the following:

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226 CW final argument, section 30.
227 LE final argument, section 27.
228 UCG final argument, paragraphs 177 to 188.
229 YCS reply argument, page 5.
230 YCS reply argument, pages 5 and 6.

> … the Board finds DSM to be a critical issue for all electric rate payers in Yukon. The Board directs YEC in conjunction with YECL, to consult with stakeholders and develop a policy paper with respect to DSM initiatives. **YEC and YECL are to jointly lead this process and submit a paper (Plan) in their next GRA**. Further the utilities are to be cognizant of and work with ESC [Energy Solutions Centre] where necessary so as not to duplicate efforts.
>
> The Plan should include initiatives developed through negotiations with intervenor groups and communities in the Yukon. The Plan should provide a wide range of energy efficiency and conservation measures that will assist ratepayers in dealing with the high cost of energy in the Yukon and also provide support for local initiatives identified through community energy planning initiatives.[231] [emphasis added]

365. The Board acknowledges YEC's submission that the DSM working group is currently in the draft stage of the five-year DSM plan which will be submitted to the Board upon completion.[232] The Board further notes YCS's submission that DSM may be more appropriately carried by a third party.

366. Considering the above, the Board finds it premature at this point to approve or disallow DSM expenses until YEC and YECL (utilities) jointly file a DSM plan as directed in Board Order 2009-08.

367. Until the plan is filed, the Board directs that:

  a) YEC create a deferral account wherein DSM O&M-related costs are to be held, and

  b) all DSM-related capital costs be held in WIP.

368. The Board directs YEC in its compliance filing to show the changes resulting from these directions.

Waste-to-energy/biomass/biogas – ($1.629 million net of contributions)

369. YEC submitted that it has considered generation options that could be locally developed, based on local sources of supply, and provide firm, reliable power. One such option, YEC submitted, relates to thermal biomass resources that can be developed with conventional technology. However, such an option requires development of relatively more capital-intensive high-pressure steam generation plants that would typically be intended for year-round operation to secure cost-efficient use of the facilities.

370. It added that such options are potentially relevant under increased grid loads that provide sufficient opportunity for the biomass generation to displace default diesel generation. Such options have been considered at a pre-feasibility stage where there is no decision to proceed with the project. These options were publically reviewed as part

[231] Board Order 2009-08: Yukon Energy Corporation Approval of Revenue Requirements for 2008 and 2009, September 8, 2009, paragraphs 40 and 41.
[232] UCG-YEC-2-5(a).

of the 2011 Energy Charette and in late 2011, YEC held two public workshops to gather input and share information.

371. Specific studies to date have centered on determining feasibility of two specific thermal sources of supply:

- Waste-to-energy; with assumed other revenues, i.e. district heat revenues and tipping fees, current municipal waste-to-energy studies estimate that a 2.2 MW plant generating 17.1 GW.h/year would have an LCOE of 13.5 cents/kW.h. Absent revenues for district heat, the LCOE would be 23.7 cents/kW.h. Absent district heat revenues and tipping fees, the LCOE is forecast to be 31.4 cents/kW.h.[233]
- Wood biomass – would not offer cost-effective displacement of diesel generation at this time.

372. Total forecast feasibility costs to the end of 2012 are $1.383 million with a $0.225 million offsetting contribution from CANNOR. Forecast feasibility study costs included in rate base at the end of 2012 are approximately $1.128 million, net of contributions. In the Application, YEC proposed that these costs be closed and amortized over 10 years starting in 2013.

373. With regard to the waste-to-energy/biomass projects, LE submitted that these projects should proceed, as they have the potential as a source of renewable power in future. LE recommended that the Board order that the waste-to-energy/biomass study costs be amortized as proposed by YEC.[234] However, LE cautioned that such studies possess inherent uncertainties as they proceed.[235]

374. UCG submitted that YEC and the Yukon government should lead pilot projects to develop alternative energy solutions that provide long-term economic benefits and reduce greenhouse gas emissions.[236]

Views of the Board

375. The Board understands that YEC needs to explore alternatives to diesel generation. The Board has concerns with the costs for this study because the pre-feasibility work alone amounts to more than $1.6 million. The ultimate question is, Who other than a generator of electrical energy should consider such a project? In this case, it is clear that this falls under the purview of YEC. However, the Board notes that the ability of ratepayers to pay for studies is not endless. Therefore, the Board accepts the costs for this project as filed but will not accept further costs on this project unless YEC can demonstrate economic viability and a reasonable probability that the project will proceed. In future, for projects such as this one, LNG and geothermal, YEC needs to determine the potential for economic viability before the studies exceed $1 million or risk disallowance of the costs.

233 Application, page 5-43.
234 LE final argument, section 27.
235 LE final argument, section 27.
236 UCG final argument, paragraph 162.

District heating ($0.5 million net of contributions)

376. YEC submitted that a developed district heating market in Whitehorse may provide added value through generation of additional revenues that may lower costs for thermal supply options and consequently reduce impacts on ratepayers. To that end, YEC indicated that preliminary findings to date point to a promising market potential of three to four MW of district heat applications within the core areas of Whitehorse.

377. YEC stated that the results from the District Energy System (DES) Pre-feasibility Study for Whitehorse (Stantec, 2010) indicate that a DES in Whitehorse is technically and economically feasible in some areas of Whitehorse. It was recommended to proceed to a full feasibility study. The purpose of this project is to determine whether or not a district energy system is feasible in the City of Whitehorse.[237] Total spending on feasibility to date has been $1.03 million, which has been offset by $0.53 million in matching contributions. YEC has proposed that the remaining $0.5 million deferred costs total be closed and amortized over five years starting in 2014.

378. Noting that district heating is a standard in Europe, LE submitted that district heating has great potential for the future. LE further recommended that the Board direct YEC to keep district heating costs in WIP.[238]

Views of the Board

379. The Board is concerned about the magnitude of expenditures for a district heating project, considering that a decision had not been made regarding the viability of such a project. Further, the Board is of the view that district heating is not the type of activity to which YEC should be applying resources nor expecting recovery from ratepayers since it is not related to electric generation or transmission of electricity. The Board does not consider this to be a prudent project and therefore directs the costs be removed from rate base and deferred costs. The Board directs YEC to reflect this finding in its compliance filing.

Liquefied natural gas (LNG) (total deferred costs of $1.7 million)

380. YEC submitted that the feasibility of thermal generation using LNG is being considered for near-term development (i.e. before 2015) as it is expected to provide a reliable, abundant, low-cost, and flexible source of supply with reduced greenhouse gas emissions and costs compared to using existing diesel generation.

381. Work in 2011 was undertaken by YEC to assess the feasibility of LNG for power generation in Yukon. The LNG feasibility study conducted by Braemar Wavespec, assessed supply chain alternatives, i.e. studied the benefits and risks associated with sourcing LNG from BC sources and from local sources at Eagle Plains. Notwithstanding, YEC submitted that further feasibility work is required to determine the optimum way to secure the LNG and also to optimize the specific YEC generation capacity and technology for power generation using LNG. A public workshop was held January 18, 2012, which reviewed this specific resource option.

[237] Application, page 5-44.
[238] LE final argument, section 27.

382. Forecast feasibility studies total $1.7 million to the end of 2012. YEC proposed a further $1-million fixed-asset expenditure in 2013, plus a transfer of $1.7 million from feasibility study costs. YEC submitted that it expects the project to meet reasonable assurance before the end of 2012 and that all costs associated with the project would be included in construction WIP as the project is developed. YEC forecast an earliest in service date of late 2014 for the project.

383. YCS expressed concerns that LNG is a substitution to another finite volatile commodity-priced fossil fuel justified by economic projections and the premise that the utility is required to service any load, however large, regardless of ratepayer impacts. YCS submitted that current costs with the inclusion of transportation have LNG on par with diesel generation, so cost is not a factor.[239] YCS submitted that large industrial customers should invest in their own LNG infrastructure for their operation.[240] LE recommended that the Board order YEC to retain LNG study costs as work in progress.

Views of the Board

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

Geothermal (total deferred costs of $2.633 million)

385. Due to the potential significant benefits of this resource — i.e. significant low cost, clean, and reliable long-term electricity supply — geothermal opportunities in Yukon have been subject to high-level review since the 2008-09 application. YEC submitted that a preliminary resource assessment and prioritization of sites, undertaken by YEC "… indicates that, while unconfirmed there is … potential at the sites identified,"[241] with Whitehorse having the highest priority ranking, because of its proximity to power infrastructure and markets.

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[239] YCS final argument, page 7.
[240] YCS final argument, page 18.
[241] Application, page 5-46.

386. YEC proposed that $1.95-million forecast feasibility study costs to the end of 2011 be closed and amortized over 10 years starting in 2012. YEC also proposed that 2012 and 2013 feasibility study costs of $0.38 million and $0.30 million respectively be amortized over five years.

387. LE considered that a significant portion of the early work regarding this project was too broad and speculative, and that some of the expenditures were imprudent. LE therefore recommended that $1 million of geothermal expenditures be disallowed and the remainder amortized as YEC proposes.[242]

Views of the Board

388. The Board notes that the test period feasibility studies are to "… confirm temperature gradient and water quality and potentially some geophysical survey work."[243] Furthermore, if 2012 study results are favorable and there is sufficient geophysical data, plans for an exploratory drilling program would be developed and undertaken to confirm heat resources. The Board considered that exploratory drilling is scheduled to occur in 2015 at the earliest.[244]

389. Similar to the Board's ruling for the studies regarding waste-to-energy projects, the Board understands that YEC needs to explore alternatives to diesel generation. Although the Board has concerns with the level of costs for studies such as this, the ultimate question is, Who other than a generator of electrical energy should consider such a project? In this case, it is clear again that this falls under the purview of YEC. Respecting the planned geothermal test-drilling expenditures, the Board considers that this program should not proceed unless YEC can demonstrate potential benefits to ratepayers in terms of the location of such potential generation being economically viable relative to the location of potential load. The Board took note that prior to the Borealis assessment, the majority of the sites that YEC reviewed were dismissed because of "… distance from major loads … the lack of transmission infrastructures … remoteness and location within a protected area … remoteness … source and distance to major loads." The Board will not accept further costs for this until YEC can demonstrate economic viability and a reasonable probability as to the likelihood of the project proceeding.

390. Considering the above, the Board accepts the geothermal expenditures as requested by YEC.

GRA phase 1 revenue requirement review ($1.1 million)

391. These are forecast costs for the preparation and fling costs of the 2012-13 Application and consideration of the Application by the Board. YEC submitted that any joint YEC/YECL cost-of-service and rate-design filing is to be undertaken at a future date to be determined; associated costs are not included in this project cost.

242 LE final argument, section 28.
243 Application , page 5-47.
244 YUB-YEC-1-50(f).

Views of the Board

392. The Board notes that interveners did raise this project as an issue. The Board considers YEC's proposed GRA Phase 1 revenue requirement review costs to be reasonable.

5.1.3.2 Projects between $100,000 and $1 million

393. YEC forecast total spending on deferred-cost activities outside of major projects over $1 million to be $2.89 million in 2012, and $2.7 million in 2013. Spending in 2012 and 2013 on each deferred-cost activity between $100,000 and $1 million is summarized in the table below.

Table 19. **Deferred projects between $100,000 and $1 million ($ million)**

Project	Year-end 2011	2012	2013	Totals
Feasibility	$3.02	$1.13	$1.0	$5.15
Deferred overhauls	0.18	1.28	1.60	3.06
Relicensing and dam safety review	0.51	0.087		0.597
Rate case	1.02	0.23		1.25
TOTALS	4.73	2.727	2.60	10.057

394. Key areas of spending within this project group include feasibility studies, deferred overhauls, relicensing, dam safety, and rate case:

- **Feasibility studies**
  - Studies undertaken to determine feasibility of potential supply options to displace diesel include Aishihik hydro re-runnering feasibility, wind feasibility – Ferry Hill, Atlin grid connection feasibility and large hydro (potential greenfield hydro projects). Other studies related to demand included a Climate Change Study to develop a plan for the corporation to mitigate and adapt to potential climate change effects on existing and future assets.
  - Studies undertaken to ensure continued reliability or determine requirement for business improvements for existing assets.
  - Studies undertaken for legal or regulatory compliance reasons include the International Financial Reporting Standards.
- **Deferred overhauls -** Hydro and diesel unit overhauls are required during the test years to ensure continued reliability.
- **Relicensing and dam safety review –** spending in 2012 related to renewal of Air Emission Licence.
- **Rate Case** - spending in the test years is focused on the preparation of the 2011 Resource Plan Update required to facilitate decision-making on major infrastructure projects.

395. LE was of the view that the aforementioned studies were appropriate. However, if YEC believes that LNG is a realistic option going forward, it will need to consider what major overhauls on the Faro and Whitehorse diesels are warranted as opposed to retiring the units from service. LE added that YEC should be putting more emphasis on wind energy. LE recommended that YEC be directed to proceed with its proposed studies, albeit with an increased emphasis on the possibilities of wind power generation, and to amortize these costs as proposed.[245]

396. Respecting its proposed deferred costs regarding major projects between $100,000 and $1 million, YEC stated that the expenditures have been tested during the proceeding and significant issues were not raised in cross-examination or argument as to the prudence of the proposed expenditures. Accordingly, YEC submitted that these costs should be deferred and amortized pursuant to its proposed planning cost accounting policy in this proceeding.

Views of the Board

397. The Board cautions YEC that feasibility expenditures associated with projects that are deemed feasible to move forward should remain in WIP until such time that the project is set aside and YEC comes before the Board for a prudence review.

398. The Board notes that interveners did not take issue with expenditures prior to the 2012 test year. Having reviewed the project expenditures YEC incurred prior to year-end 2011, the Board finds the expenditures prudent and directs that they be capitalized. Moreover, for project expenditures incurred in the test years and beyond, the Board directs that these expenditures be held in WIP until such time the costs are brought before the Board for a prudence review and have been approved. The Board directs YEC to incorporate these findings into its compliance filing.

5.2 New planning cost accounting policy (PCAP)

399. YEC proposed a new planning cost accounting policy in Appendix 5.1 of the Application, in which it outlined an accounting policy for expenditures related to system studies. YEC submitted that the policy was required to address material accumulated deferred costs in WIP and to mitigate impacts on ratepayers in the test years. Based on the new PCAP, YEC sought approval to include in rate base spending to date for deferred-cost projects as noted in Tab 5, Section 5.3.

400. CW indicated that it did not take issue with the policy and submitted that customers should bear the cost of these studies over time as “These studies must be undertaken to determine alternatives that will result in the least-cost generation to customers. Customers even benefit from studies that do not result in projects as the utility will have avoided a high-cost option.”[246] For projects — included in Tables 5.3 to 5.7 of the Application — that have passed a reasonable assurance test, CW submitted that YEC should be directed to reclassify the study as a capital project.

[245] LE final argument, section 29.
[246] CW final argument, paragraph 31.

401. LE argued that since the Marsh Lake, Gladstone Diversion and District Heating projects remain viable, the associated costs should remain in WIP until completed or abandoned.

402. UCG, on the other hand, argued that no amortization of a project should occur until a project is brought into service. Furthermore, if a project is abandoned or cancelled, study costs should be amortized without earning a return.[247] UCG submitted that YEC has not provided evidence from other jurisdictions where feasibility expenditures are not recorded in a deferral account and, if the project goes ahead, the costs are transferred to an appropriate utility plant account for recovery.[248]

403. YEC submitted that the policy was designed to balance the requirements for a utility to undertake planning and study work that is "… critical to the Corporation's mandate and the need to ensure rate stability over time. Rate stability is provided through deferring and amortizing costs over a defined period instead of either expensing such costs in the year incurred, or deferring such costs until such time as a final decision is made on project feasibility."[249] YEC submitted that, other than LE's relaxation of the reasonable assurance test for three projects, LE's argument supports the planning cost accounting policy as proposed. YEC argued that UCG's argument that the Board should reject rate base treatment for deferred study costs is without merit.

Views of the Board

404. The Board has concerns respecting YEC's proposed planning cost accounting policy. With regard to the policy, the Board notes that:

> Future expenditures will not be recognized as work-in-progress assets until such time … a Corporation commitment to construction will be made.
> In the event a project is abandoned … accrued costs will be amortized over 10 years.
> Planning costs incurred in relation to major projects that … will promptly be closed out in annual stages, and amortized over 5 years"[250]

405. The Board does not accept the policy as the Board and interveners must be given the opportunity to test the prudence of all costs incurred by YEC in respect of deferred costs. Accordingly, the Board considers that the policy as proposed would allow the inclusion of these costs without any prior scrutiny by the Board and interveners. Considering the above, the Board rejects YEC's proposed planning cost accounting policy.

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[247] UCG final argument, paragraph 85.
[248] UCG final argument, paragraph 96.
[249] YEC reply argument, page 64.
[250] Application, Appendix 5.1, Planning Policy.

5.3 New demand-side management accounting policy

406. In Appendix 5.2 of the Application, YEC included a proposed new DSM accounting policy as well as a proposal to amortize related deferred costs over the test years.

Views of the Board

407. As stated above, the Board defers its findings and directions regarding YEC’s DSM accounting policy until YEC and YECL have jointly filed a DSM plan as directed in a prior section.

Appendix 1 – Partial Summary of Board 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. Refer to the Reasons for Decision document for a complete list of directions.

1. The Board is of the view that YECL may have more up-to-date information regarding the unavailability of Fish Lake Hydro during the 2012-2013 test period. The Board directs YEC to consult with YECL regarding the unavailability of Fish Lake Hydro during the 2012-13 test period and adjust its forecast if necessary in its compliance filing. .... Paragraph 35
2. 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. This allows all parties to make submissions on any new information. Accordingly, the Board directs YEC to update its major industrial sales forecast in its compliance filing to account for the change to the 2012 and 2013 Minto sales forecasts referred to in the hearing. .... Paragraph 39
3. As a result of the above, the Board finds that YEC is not entitled to serve WHCT because it is a customer within the YECL franchise area and under Section 1 of the regulation, YEC cannot provide electrical service in areas where it is already provided by YECL. The Board therefore directs YEC in its compliance filing to remove WHCT volumes from its industrial sales forecast and include those volumes in its wholesale sales forecast for the test years and to adjust its revenue requirement accordingly. .... Paragraph 49
4. The Board denies YEC's request to credit secondary sales revenue directly to the DCF for the reasons set out in Section 3.6. As a result, the Board directs YEC to forecast, manage and account for secondary sales (if there are any) as part of its energy sales. The Board directs YEC to reflect this finding and direction in its compliance filing. .... Paragraph 52
5. Based on its findings respecting the DCF and ERA in Section 3.6, the Board does not accept the proposed transition from 2009 rates. The Board directs YEC to base its hydro and diesel energy requirements on 100 percent of long-term average hydro generation for the forecast load in its compliance filing. In that compliance generation forecast, YEC is to confirm whether the effect of the Mayo A runner improvements have been included in the forecast. If not, YEC is to update its generation forecast accordingly. .... Paragraph 60
6. The Board has reviewed YEC's 2012 and 2013 fuel and price forecast and finds the forecast reasonable. However, the Board notes that directions in other areas of this decision, including the sales forecast section, may have an impact on YEC's fuel and purchase forecast. The Board directs YEC to review and to explain the impacts of the changes in other sections on the fuel and purchased power forecast in YEC's compliance filing. .... Paragraph 68
7. The Board directs YEC to remove all labour costs attributable to DSM and the ECD from the revenue requirement for the 2012 and 2013 test years in its compliance filing. The Board directs YEC to track and defer these costs until the

Board approves a final DSM policy for YEC, as discussed in Section 5.3. .... Paragraph 85

8. 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 be in the newly created vegetation management deferral account. .... Paragraph 108

9. 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 reasonableness of the proposed policy and the costs held in the vegetation management deferral account. .... Paragraph 109

10. As was done respecting transmission vegetation management costs, the Board accepts YEC's proposed distribution brushing costs for the test years. However, for the period beyond the test years (future years) the Board directs YEC to create a distribution vegetation management deferral account. In future years, distribution vegetation management related costs greater than 2011 actual brushing costs are to held in the newly distribution created vegetation management deferral account. .... Paragraph 117

11. The Board further directs YEC, in its next GRA, 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. .... Paragraph 118

12. The Board agrees with LE that a $0.201 million increase (i.e. a 191-percent increase over 2009 approved forecast) in discretionary spending when rates are increasing is not acceptable. Further, the Board finds that YEC has not provided adequate evidence to satisfy the Board that ratepayers would exchange more communication for higher utility rates. The Board directs YEC in its compliance filing to reduce the communication forecasts to $0.105 million for each of the 2012 and 2013 test years. .... Paragraph 134

13. The Board accepts YEC's proposed three-part solution and directs YEC to make the $0.005-million reduction to the RFID appropriation it noted in reply argument in the compliance filing. .... Paragraph 168

14. The Board finds that there is little reason to depart from the previous approach and YEC has not provided any explanation for not conducting any further analysis or departing from the previous approach. The Board accepts the recommendation of CW, which was supported by UCG, and directs YEC in its compliance filing to use 3.97 percent as the forecast cost for new debt for 2012 and 3.58 percent as the forecast cost for new debt for 2013. .... Paragraph 194

15. The Board has determined that the simplified approach is the approach to be used in determining the ROE for utilities under its jurisdiction. The simplified approach was based on the precedence of the BCUC formulaic model. In this proceeding, since recent results of the BCUC model are not available, YEC can

use the benchmark results from the AUC model. Therefore, the Board directs YEC in its compliance filing to use an ROE of 8.25 percent. .... Paragraph 230

16. The Board does not approve YEC's proposed DCF but directs YEC to provide a revised DCF proposal. In the revised DCF proposal, YEC is to incorporate other non-diesel generation facilities (wind, Fish Lake hydro) forecasts into its model. In addition, YEC is to incorporate the suggestions of CW and UCG as to how DCF transactions are to be reported. Further, in that submission, YEC is to provide an example of approximately five years of transactions that will show how the balance in the DCF will change and how those changes will be reported. Finally, YEC is to work with YECL, and the two utilities will provide a joint recommendation on how the DCF will affect the Energy Reconciliation Account in Rate Schedule 42 and any proposed wording changes to that rate schedule. The Board will leave it to the discretion of YEC and YECL as to when the revised DCF proposal is to be filed with the Board. Given the foregoing, the Board does not approve YEC's requests regarding the DCF and therefore does not approve YEC's proposed changes to Rider F. Secondary sales, as they occur, will continue to be credited to the Rider F account. .... Paragraph 255

17. As a result of the Board determination regarding the DCF, YEC's proposed changes for secondary sales is moot. YEC is directed to continue applying any secondary sales to the Rider F account. .... Paragraph 260

18. As the Board has requested YEC to file a revised DCF, and to address the concerns raised by the Board in that filing, the Board directs YEC to refile a Rate Schedule 42 in cooperation with YECL as directed in Section 3.6.2 of this decision .... Paragraph 281

19. Respecting UCG's concern with the inclusion of Western Copper aerial mapping and route-selection charges, the Board notes YEC's acknowledgement that Western Copper aerial mapping and route-selection expenses should have been held in work in progress (WIP). The Board directs YEC in its compliance filing to move the aerial photo mapping and route-selection charges ($30,233) related to the Western Copper grid connection project into WIP to be charged later to Western Copper. .... Paragraph 301

20. The Board has concerns with the escalation of costs, but the Board notes that additional projects were undertaken at the time when the redundant cabling system was replaced. The Board has reviewed the project costs and has not seen any evidence that the additions to the project were unnecessary or not useful. Therefore, the Board approves the project costs as filed. However, in future, the Board directs YEC is to provide business cases for all projects, including reliability projects, greater than $1 million. These business cases are to include alternatives to the recommended projects as well as the economic impact to ratepayers of the recommended projects. .... Paragraph 313

21. The Board notes that the invoices relate to a YEC planned outage in respect of one of its major projects. As part of YEC's feasibility study work leading up to the decision, whether or not the project is given the go ahead, the Board considers that YEC would investigate and determine all costs that relate to such projects. The Board finds that it is YEC's obligation to forecast all future costs, including all

third party costs, such as YECL utility costs that relate to YEC's proposed capital projects. The Board directs YEC to consult with YECL to determine costs that are to be incurred by YECL, as a result of YEC's proposed capital project costs. The Board further directs YEC to include such costs in future GRAs for Board and intervener review. .... Paragraph 316

22. The Board does acknowledge YEC's submission that "there would be benefit to [us] having visibility into these diesels in instances where we have outages and we're trying to bring them [Minto] back onto the grid." Again, YEC has not demonstrated or quantified what the benefit to ratepayers would be. Therefore, the Board directs YEC in its compliance filing to remove all Minto-related SCADA costs from rate base. .... Paragraph 324

23. The Board finds that Gladstone hydro enhancement project has potential to be a viable project and directs that all project expenditures be held in WIP until the project is completed. Moreover, YEC is to cease work on this project if and when YEC concludes that there is no net economic benefit of the project to ratepayers. .... Paragraph 344

24. Until the plan is filed, the Board directs that:

a) YEC create a deferral account wherein DSM O&M related costs are to be held, and

b) all DSM-related capital costs be held in WIP. .... Paragraph 367

25. The Board directs YEC in its compliance filing to show the changes resulting from these directions. .... Paragraph 368

26. The Board is concerned about the magnitude of the expenditures for a district heating project, considering that a decision had not been made regarding the viability of such a project. Further, the Board is of the view that district heating is not the type of activity to which YEC should be applying resources nor expecting recovery from ratepayers since it is not related to electric generation or transmission of electricity. The Board does not consider this to be a prudent project and therefore directs the costs be removed from rate base and deferred costs. The Board directs YEC to reflect this finding in its compliance filing. .... Paragraph 379

27. The Board notes that interveners did not take issue with expenditures prior to the 2012 test year. Having reviewed the project expenditures YEC incurred prior to year-end 2011, the Board finds the expenditures prudent and directs that they be capitalized. Moreover, for project expenditures incurred in the test years and beyond, the Board directs that these expenditures be held in WIP until such time the costs are brought before the Board for a prudence review and have been approved. The Board directs YEC to incorporate these findings into its compliance filing. .... Paragraph 398

28. The Board does not accept the planning cost accounting policy as the Board and interveners must be given the opportunity to test the prudence of all costs incurred by YEC in respect of deferred costs. Accordingly, the Board considers that the policy as proposed would allow the inclusion of these costs without any

prior scrutiny by the Board and interveners. Considering the above, the Board rejects YEC's proposed planning cost accounting policy .... Paragraph 405

29. The Board defers its findings and directions regarding YEC's DSM accounting policy until YEC and YECL have jointly filed a DSM plan as directed in a prior section .... Paragraph 407