

Yukon Utilities Board

Board Order 2024-01

Appendix A: Reasons for Decision

May 31, 2024

Table of Contents

1	Introduction	1
2	AEY Sales and Revenue and Purchase Power	2
2.1	Overview of Sales and Revenue	2
2.1.1	Views of AEY	3
2.1.1.1	Residential sales forecast.....	3
2.1.1.2	Commercial sales forecast.....	4
2.1.2	Views of interveners.....	4
2.1.3	Board Findings	5
2.2	Overview of Purchase Power	6
2.2.1	Views of AEY	6
2.2.2	Views of interveners.....	6
2.2.3	Reply of AEY.....	8
2.2.4	Board Findings	8
3	Fuel costs.....	9
3.1	Views of AEY	9
3.2	Views of interveners	9
3.3	Board Findings	9
4	Operations and maintenance (O&M) expense (excluding fuel costs)	10
4.1	Overview	10
4.2	Views of interveners	11
4.3	Key assumptions and FTE's.....	12
4.3.1	Views of AEY	12
4.3.2	Board Findings	13
4.4	Views of AEY- Non-labour O&M – Public Information	13
4.4.1	Account 70100 - Public Information Administration	13
4.4.2	Board Findings	14
4.4.3	Account 70200 – General Public Information	15
4.4.3.1	Board Findings.....	15
4.5	Views of AEY - Non-labour O&M – Account 72100 - Administrative	15
4.5.1	Board Findings	17
5	Depreciation expense	18
5.1	Overview	19
5.2	Average service life and Iowa curve.....	22
5.2.1	Views of AEY	22
5.2.2	Board Findings	23
5.3	Net salvage.....	23
5.3.1	Views of AEY	23
5.3.2	Alternatives to the traditional net salvage method for the re-instatement of the pre-collection of net salvage	24
5.3.3	Traditional net salvage method	25
5.3.4	Views of the intervenors.....	25

5.3.5	Board Findings.....	26
5.3.6	Views of AEY - Net salvage per cents.....	26
5.3.7	Views of AEY - Account 331.00 – Generation Hydro – Structures and Improvements	27
5.3.7.1	Board Findings.....	28
5.3.8	Views of AEY - Account 332.00 –Generation Hydro – Reservoirs, Dams and Waterways	28
5.3.8.1	Board Findings.....	28
5.3.9	Views of AEY - Account 333.00 – Generation Hydro – Water Wheels, Turbines and Generators	29
5.3.9.1	Board Findings.....	29
5.3.10	Views of AEY - Account 335.00 – Generation Hydro – Miscellaneous Power Plant Equipment ...	30
5.3.10.1	Board Findings.....	30
5.3.11	Views of AEY - Account 341.20 – Generation Diesel – Internal Combustion Structures	30
5.3.11.1	Board Findings.....	31
5.3.12	Views of AEY - Account 342.20 – Generation Diesel – Internal Combustion Fuel Holders, Producers and Accessories	31
5.3.12.1	Board Findings.....	32
5.3.13	Views of AEY - Account 343.20 – Generation Diesel – Internal Combustion Generators.....	32
5.3.13.1	Board Findings.....	33
5.3.14	Views of AEY - Account 345.20 - Generation Diesel – Internal Combustion Accessory.....	33
5.3.14.1	Board Findings.....	34
5.3.15	Views of AEY - Account 346.20 - Generation Diesel – Internal Combustion Miscellaneous	34
5.3.15.1	Board Findings.....	34
5.3.16	Views of AEY - Account 362.00 – Distribution – Station Equipment.....	35
5.3.16.1	Board Findings.....	35
5.3.17	Views of AEY - Account 362.10 – Distribution - System Communication and Control	36
5.3.17.1	Board Findings.....	36
5.3.18	Views of AEY - Account 364.00 – Distribution - Poles, Towers and Fixtures	37
5.3.18.1	Board Findings.....	37
5.3.19	Views of AEY - Account 365.00 – Distribution – Overhead Conductors and Devices	38
5.3.19.1	Board Findings.....	38
5.3.20	Views of AEY - Account 365.10 – Distribution – Overhead Services.....	38
5.3.20.1	Board Findings.....	39
5.3.21	Views of AEY - Account 367.00 – Distribution – Underground Conductor and Devices	39
5.3.21.1	Board Findings.....	40
5.3.22	Views of AEY - Account 367.10 – Distribution – Underground Services	40
5.3.22.1	Board Findings.....	41
5.3.23	Views of AEY - Account 368.00 – Distribution – Line Transformers	41
5.3.23.1	Board Findings.....	41
5.3.24	Views of AEY - Account 370.00 – Distribution – Conventional Meters.....	41
5.3.24.1	Board Findings.....	42
5.3.25	Views of AEY - Account 373.00 – Distribution – Street Lights	42
5.3.25.1	Board Findings.....	43
5.3.26	Views of AEY - Account 373.10 – Distribution - Sentinel Lights	43
5.3.26.1	Board Findings.....	43
5.3.27	Views of AEY - Account 390.00 – General Plant – Structures and Improvements.....	43
5.3.27.1	Board Findings.....	44
5.3.28	Views of AEY - Account 390.01 – General Plant – Structures and Improvements Houses	44
5.3.28.1	Board Findings.....	45
5.3.29	Views of AEY - Account 392.20 – General Plant – Transportation Equipment, Fleet Vehicles Category 2	45
5.3.29.1	Board Findings.....	45
5.3.30	Remaining accounts	46
5.4	<i>Board directions on AEY’s calculation of the amortization of reserve differences</i>	<i>46</i>

5.5	<i>Proposed treatment of contributions</i>	47
5.5.1	Views of AEY	47
5.5.2	Board Findings	48
5.6	<i>Board directions on AEY's amortization of Fish Lake Water Licence and Demand Side Management (DSM) program study costs</i>	49
6	Return on rate base	49
6.1	<i>Views of AEY</i>	49
6.1.1	Return on Rate Base	49
6.1.1.1	Cost of capital	50
6.1.1.2	Rate of return on capital	50
6.1.1.3	Views of interveners	50
6.1.1.4	Board Findings.....	50
6.1.2	Views of AEY on Equity premium	52
6.1.2.1	Views of interveners	53
6.1.2.2	AEY reply to interveners	55
6.1.2.3	Board Findings.....	56
6.1.3	Views of AEY on Common equity ratio	61
6.1.3.1	Views of interveners	61
6.1.3.2	Board findings	62
6.2	<i>Cost of debt</i>	62
6.2.1	Views of AEY	62
6.2.2	Views of interveners.....	62
6.2.3	Board Findings	62
6.2.4	No cost capital	63
7	Capital	63
7.1	<i>Overview</i>	63
7.2	<i>Views of AEY - opening rate base</i>	65
7.2.1	Views of interveners.....	66
7.2.2	Views of AEY	67
7.2.3	Board Findings	67
7.3	<i>Views of AEY on its ability to complete its forecast capital expenditures and additions</i>	68
7.3.1	Views of the interveners.....	69
7.3.2	Board Findings	69
7.4	<i>Generation plant</i>	70
7.4.1	Views of AEY on generation projects related to Fish Lake (Business cases 32 and 39)	70
7.4.2	Board Findings	70
7.4.3	Views of AEY on Remaining forecast generation projects	71
7.4.4	Views of interveners.....	71
7.4.5	Board Findings	71
7.5	<i>Distribution plant</i>	71
7.5.1	Distribution improvements - Substation Mayo Road and Substation Whistle Bend Leota (Business Case 25)	72
7.5.1.1	Views of interveners	73
7.5.1.2	Board Findings.....	73
7.5.2	Views of AEY on Distribution improvements – 6L19 Voltage Improvement (Business Case 30) ..	74
7.5.2.1	Views of interveners	75
7.5.2.2	Board Findings.....	75

7.5.3	Views of AEY on Distribution improvements – Downtown Whitehorse Capacity Increase (DWCI) – New 12.5kV Substation (no business case provided)	76
7.5.3.1	Board Findings.....	76
7.5.4	Views of AEY on Distribution – Advanced Metering Infrastructure (AMI) Project New Meters (Business Case in AEY-YUB-065(a) Attachment 1)	77
7.5.4.1	Views of interveners	78
7.5.4.2	Board Findings.....	78
7.5.5	Views of AEY on Distribution – Street and sentinel lighting	79
7.5.5.1	Views of interveners	79
7.5.5.2	Board Findings.....	79
7.6	<i>General property plant & Equipment (GPE)</i>	80
7.6.1	Views of AEY on GPE - ATCO CIS replacement project (Business Case 22)	80
7.6.1.1	Views of interveners	80
7.6.1.2	Board Findings.....	81
7.6.2	Views of AEY on GPE – Asset Management Project (Business Case 24).....	81
7.6.2.1	Views of interveners	81
7.6.2.2	Board Findings.....	81
7.6.3	Views of AEY on GPE – Salesforce (Business Case in AEY-YUB-066(b) Attachment 1)	82
7.6.3.1	Views of interveners	82
7.6.3.2	Board Findings.....	82
7.6.4	Views of AEY on GPE – Tools and Transportation (Business Cases 1, 2, 3 and 4)	83
7.6.4.1	Views of interveners	83
7.6.4.2	Board Findings.....	83
8	Income Tax	83
8.1	Views of AEY	83
8.2	Board Findings	84
9	Deferral and reserve accounts and no-cost capital account	84
9.1	Views of AEY	84
9.1.1	Board Findings.....	85
9.2	<i>Industrial Rider R deferral account</i>	85
9.2.1	Board Findings	86
9.3	<i>Purchase Power Flow Through Deferral Account</i>	86
9.3.1	Board Findings	86
9.4	<i>Diesel fuel deferral account</i>	86
9.4.1	Board Findings	87
9.5	Views of AEY on Demand side management (DSM) program deferral account	87
9.5.1	Board Findings	88
9.6	Views of AEY on Board Orders or changes in legislative provisions deferral account.....	88
9.6.1	Views of interveners.....	89
9.6.2	Board Findings	89
9.7	Views of AEY on IPP Flow-Through	90
9.7.1	Views of interveners.....	91
9.7.2	Board Findings	91
10	Previous board directions	92

List of Tables

Table 1: AEY energy sales by customer class 2016-2024 (MWh)	3
Table 2: 2016-2024 Purchase Power (\$000s)	6
Table 3: Wholesale purchases (AEY/YEC perspectives)	7
Table 4: AEY Fuel costs (\$000)	9
Table 5: Summary of total labour and non-labour O&M expenses (excluding fuel costs) Actual, Test Period forecast and Approved by function (\$000)	10
Table 6: Summary of key assumptions forecast for 2023-2024 (%)	12
Table 7: Breakdown of Account 72100 – Administrative (labour and non-labour), Actual (A) and Forecast (F) costs 2016-2024 (\$000)	16
Table 8: Breakdown of Account 72100 – Administrative - Head office services (non-labour) Actual (A), F Forecast (F) and Approved (Appr) costs 2016-2024 (\$000)	16
Table 9: Summary of historical actual (A) and forecast (F) depreciation expense by category	18
Table 10: Factors causing the increase in 2023 forecast depreciation expense compared to 2022 actual	19
Table 11: AEY 2007-2022 actual (A) and 2023-2024 forecast (F) negative net salvage reserve account (\$ millions)	21
Table 12: AEY 2023-2024 forecast net salvage costs included in depreciation expense	23
Table 13: AEY Return on Rate Base (\$000)	49
Table 14: Concentric view of authorized ROEs and equity ratios	52
Table 15: Economic Indicators (%)	62
Table 16: Summary of actual (A), approved (Appr) and forecast (F) capital expenditures and additions for the years 2016-2024 (\$ millions)	63
Table 17: AEY's capital expenditures: actual to October 31, 2023, full-year forecast and applied-for (\$ millions)	68
Table 18: Capital Expenditures – Generation (\$000)	70
Table 19: Summary of Distribution actual (A), approved (Appr) and forecast (F) capital expenditures for the years 2016-2024 (\$ millions)	72
Table 20: Mayo Road and Whistle Bend – Leota forecast cost and in-service dates (\$ millions)	73
Table 21: 6L19 Voltage Improvement – project schedule and forecast costs (\$ millions)	74
Table 22: Street and Sentinel Lights (\$000)	79
Table 23: Capital Expenditures – General Property and Equipment (GPE) (\$000)	80
Table 24: Summary of existing and proposed deferral and reserve accounts	84
Table 25: Board-prepared summary of AEY's responses to Board Order 2017-01, Appendix A.	92

1 Introduction

1. On July 7, 2023, ATCO Electric Yukon (AEY or applicant) filed an application with the Yukon Utilities Board (Board), pursuant to the *Public Utilities Act* (PUA) and Order-in-Council (OIC) 1995/90 (referred to as “Rate Directive Policy [1995],” as amended by OIC 2018/220 and OIC 2021/16, for approval of its forecast revenue requirements of \$60.992 million for 2023 and \$68.096 million for 2024. The revenue requirement amounts were subsequently updated during the proceeding. AEY’s last General Rate Application (GRA) was submitted in May 2016.
2. On July 14, 2023, the Board issued Board Order 2023-13 providing notice of the Application and setting out the following process steps: intervener registration; an AEY procedural conference on the Application; two rounds of Information Requests (IRs) to AEY and AEY IR responses; filing of intervener evidence; an oral hearing; and written final and reply arguments. Board Order 2023-13 also denied AEY’s requests for a negotiated settlement process and for each intervener’s IRs to be limited to 50 questions including parts thereof.
3. Ministerial approval was granted for this proceeding on July 20, 2023.
4. In Board Order 2023-14 (and the erratum to that Order), the Board granted intervener status to Yukon Energy Corporation (YEC), the Utilities Consumers’ Group (UCG), John Maissan, Nathaniel Yee, Florian Boulais, the Yukon New Democratic Party (NDP) Caucus and the Yukon Conservation Society (YCS). The Board invited any members of the public who wished to make their views known without registering as an intervener to make a presentation. The Board granted Frank Bachmier and the Canadian Federation of Independent Business (CFIB) presenter status.
5. In response to requests from the Applicant and interveners, the Board issued Board Order 2023-15 on August 17, 2023, amending the process schedule and then, at the request of the Applicant, Board Order 2023-18 on August 29, 2023, further amending the process schedule.
6. The Board issued Board Order 2023-22 on September 15, 2023, approving interim rates for AEY effective January 1, 2024.
7. In Board Order 2023-24, the Board ruled on motions for further and better IR responses.
8. The Board held an oral hearing on November 27-30, 2023, in Whitehorse with some virtual attendance. The parties filed written final and reply arguments in accordance with the process schedule.
9. The record of this proceeding closed on December 20, 2023 — the date written reply argument was filed by parties.

10. In reaching the determinations contained within this Board Order, 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 these reasons for 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.
11. The Board has determined that not all of the forecast revenue requirements for the 2023-2024 test period are reasonable and has consequently adjusted or denied specific components of the revenue requirement. Because the revenue requirement is not approved in full, AEY shall submit a compliance filing with respect to its 2023-2024 GRA within 30 days of the issuance of this Board Order.
12. The Board notes that during this proceeding, and as referenced in paragraph 6 above, it approved an interim rate rider increase for retail and industrial firm rates effective January 1, 2024, in Board Order 2023-22. The compliance filing to this Board Order will finalize the revenue requirement and true up interim rates.
13. In this Appendix, the Board sets out its findings and the reasons for them. All requests in the Application not specifically addressed in the sections that follow are approved by the Board.

2 AEY Sales and Revenue and Purchase Power

2.1 Overview of Sales and Revenue

14. In its application, AEY stated that during 2022, it provided electricity services to approximately 20,300 non-lighting customers in its service area and supplied a total of 361.3 GWh to Residential, Commercial, and lighting customers.
15. AEY further noted that after a period of moderate growth, the Yukon economy was disrupted by the pandemic starting in 2020. Due to the impact of COVID-19 restrictions, Residential Usage per Customer (UPC) increased significantly as more people worked from home, and Commercial UPC decreased due to the impact of COVID-19 restrictions. As restrictions were lifted, policies and procedures normalized. Now, UPCs are returning to pre-pandemic levels.
16. AEY stated its forecast process involves the review of historic sales data at the community level and includes the most recent data available at the time the forecast is prepared. AEY obtained its information through its on-the-ground work in the communities and through consultation with the City of Whitehorse, Yukon government, and various local agencies and developers. Retail primary sales are forecast at the customer class level for residential, commercial, street, and private lighting.

17. Table 2.1: AEY Sales by Customer Class in the Application summarizes AEY’s energy sales forecast for the 2023 and 2024 test years with actual results for the years 2016 to 2022. The forecast was updated in response to UCG-AEY-1-17(e).¹ The following table provides the updated summary:

Table 1: AEY energy sales by customer class 2016-2024 (MWh)

	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals							Test Period	
Residential	151,351	165,654	167,596	166,455	185,235	188,526	188,388	187,840	195,966
Commercial	157,662	165,924	168,285	168,680	163,933	166,022	168,541	170,146	175,244
Streetlights	3,923	3,942	3,951	3,876	3,889	3,937	3,884	3,878	3,883
Private lights	496	495	486	480	452	452	456	441	431
Total Retail Primary	313,432	336,016	340,318	339,491	353,508	358,936	361,269	362,304	375,523
Secondary Sales	4,835	8,385	258	1	479	4,430	3,439	1,861	2,931
Wholesale Sales	548	584	636	693	704	487	420	456	451
Total Company	318,815	344,985	341,212	340,184	354,691	363,853	365,128	364,621	378,905

Source: Exhibit B-4, AEY Consolidated IR Responses, AEY-UCG-017, PDF page 260.

18. AEY’s application forecast total primary retail sales would increase by 0.2 per cent in 2023 and by 3.7 per cent in 2024. For this GRA, AEY applied UPC growth rates from the 2017-2019 timeframe rather than using UPC growth rates from the 2020-2022 timeframe. This represented a change in its forecast approach from the 2016-17 GRA where the UPC growth rates for the years immediately preceding the GRA were used. AEY’s reasoning was that UPC growth rates from the 2017-2019 timeframe are more representative of the future of Yukon rather than growth rates for 2020-22 which were influenced by the COVID-19 pandemic.

2.1.1 Views of AEY

2.1.1.1 Residential sales forecast

19. AEY stated that the Residential forecast has two key inputs: net customer additions and the UPC. The energy sales forecast is obtained by multiplying the forecast number of customers, which includes all known residential property developments, by the weather-normalized UPC forecast.
20. Keno City, Stewart Crossing and Swift River are exceptions to this practice. These communities are forecast by using the actual UPC of the previous year as a base and applying the 2017 to 2019 growth in actual UPC. The actual UPC for these three communities are used because there are very few customers. The community energy sales forecast is then calculated by multiplying the forecast community customer counts by the respective community UPC forecast.

¹ Exhibit B-4, AEY Consolidated IR Responses, AEY-UCG-017, PDF page 260.

2.1.1.2 Commercial sales forecast

21. Similar to the residential sales forecast, the commercial sales forecast has two key inputs: net customer additions and the forecast UPC. The energy sales forecast is determined by multiplying the forecast number of customers (based on the net customer additions forecast) by the UPC forecast.
22. For Whitehorse, the commercial UPC is forecast by using the weather-normalized UPC of the previous year as a base and applying the 2017 to 2019 growth rate of weather-normalized UPC. AEY added that it expects six new large commercial customers to be added during the test period in Whitehorse. An additional large customer is forecast for Carcross. AEY submitted it has considered these new large customers individually and has forecast the load each customer will bring to the system each year based on the start-up time and other pertinent information provided by the customers. The commercial energy sales for Whitehorse and Carcross were then calculated by adding the specific energy sales of the new large commercial additions to each of the test years.
23. AEY submitted that the commercial UPC forecast for all communities outside Whitehorse is properly determined by using the actual UPC of the previous year and applying the 2017 to 2019 growth in actual UPC. AEY explained that actual UPC is used because there are fewer commercial customers in these communities or there is poor correlation between their average UPC and temperature. The community energy sales forecast is then calculated by multiplying the forecast community customer counts by the respective community UPC forecast.

2.1.2 Views of interveners

24. Mr. Maissan's view was that the AEY primary retail sales forecast is reasonable and should be approved by the Board.²
25. The UCG submitted that AEY should have included data from 2022 in its forecast as the pandemic was waning, and construction and new growth continued at a normal rate. In response to AEY's assertion that they did not have exact data on the profile contributing to changes, the UCG stated that 2022 actuals are even more important to compare to 2023 sales.³ The UCG recommended that the Board order AEY to increase its sales/revenue forecast by five per cent to consider growth patterns and the increase in electrification revenues. In its argument, the UCG added that AEY did a poor job supporting how they tallied their sales and revenues to demonstrate their

² Maissan Final Argument, PDF page 2.

³ UCG Final Argument, PDF page 6.

revenue requirement for each test year and requested the Board to direct AEY to improve this in their next GRA.⁴

26. AEY replied to the UCG argument by stating:

... the UCG's arbitrary and unsupported recommendation that AEY be ordered to increase its sales and revenue forecast should be rejected, as the UCG has failed to draw any clear link between the quantum of that recommendation and the exhibits it cites in support of the same. Moreover, the UCG fails to account for the evidence and testimony of Mr. Martino, which demonstrated that AEY's sales forecasts have historically been very accurate, with the exception of years such as 2017 when unexpected and unprecedented economic and population growth was experienced.⁵

2.1.3 Board Findings

27. The Board considered AEY's explanation⁶ that its sales forecast process usually involves the review of historic sales data at the community level and usually includes the most recent data available at the time the forecast is prepared. The information was obtained through AEY's work in the community, as well as consultation with the City of Whitehorse, Yukon government, and various local agencies and developers. This information is used to prepare the retail primary sales forecast by customer class (residential, commercial, street, and private lighting).
28. However, the Board accepts the change in sales forecasting methodology for this test period. That is, the effect of the COVID-19 pandemic on forecast sales for the years 2020-2022 can be considered an outlier. Thus, the exclusion of the years 2020-2022 for determining the five-year average UPC growth rates is a reasonable measure taken by AEY in developing its sales forecast for the 2023-2024 test period. However, the Board directs AEY, in its next GRA, to revert to the methodology approved by the Board in AEY's 2016-2017 GRA.⁷
29. Accordingly, the Board accepts the forecast process used by AEY for the 2023-2024 test years. The AEY approach is built from the bottom up. That is, it looks at each community, adjusts for material changes in growth, and will also apply a trending UPC rate for that community. AEY also adjusts the forecast for expected changes in commercial customers. Other than the application of UPCs, the Board finds the forecast process consistent with previously approved methods and finds the sales forecast for these test years reasonable.

⁴ UCG Reply Argument, PDF page 4.

⁵ YEC Reply Argument, PDF page 16.

⁶ Exhibit B-1, Application, PDF page 27.

⁷ AEY is to use the average, of the growth rates for UPC from the 5 years preceding the test period.

2.2 Overview of Purchase Power

2.2.1 Views of AEY

30. AEY submitted that its primary and secondary purchase power costs are forecast to remain relatively flat over the test period. The following table from the application shows the actual and forecast purchase power over the 2023-2024 test period:

Table 2: 2016-2024 Purchase Power (\$000s)

	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals							Test Period	
Primary Purchase Power	25,108	27,069	27,658	27,507	28,817	28,959	28,796	29,015	30,086
Secondary Purchase Power	243	460	16	0	8	330	276	358	358
Less: Capitalized	-216	-5	0	-88	0	0	0	-49	0
Total Wholesales Purchased Power	25,135	27,525	27,674	27,419	28,825	29,289	29,072	29,323	30,444
Independent Purchases	-	-	-	-	-	143	426	455	517
Total Purchase Power	25,135	27,525	27,674	27,419	28,825	29,432	29,498	29,778	30,961

Source: Exhibit B-1, Application, Table 3.1, PDF page 107.

31. The Primary Purchase Power costs are based on the currently approved Rate Schedule 42, effective July 1, 2011, and the Secondary Purchase Power costs are based on the April 1, 2023, Quarterly Rate Schedule 43.
32. AEY forecasts that it will purchase 90.9 per cent and 91.0 per cent of its power needs from YEC in the 2023 and 2024 test years, respectively. The remainder of AEY's power supply is provided by diesel generation, hydro generation,⁸ independent power purchases,⁹ and the microgeneration¹⁰ program.¹¹ AEY's energy purchase forecast takes into account line losses by applying a forecast line loss percentage to AEY's sales load forecast. AEY's sales are based on customer usage, regardless of the source of the energy provided to the customer.¹²

2.2.2 Views of interveners

33. YEC was the only party to comment on purchase power and limited its comments to primary wholesale purchases.

⁸ Hydrogeneration is based on Fish Lake output for the 2021-2022 period including planned maintenance, water availability and adjusted for any planned decreases due to capital rebuilds.

⁹ IPP supply is based on the dispatch protocol with Vuntut Gwitchin First Nation.

¹⁰ Microgeneration is based on a linear regression from the last 5 years of exported energy. Beaver Creek and Old Crow exports were based on a 4-year regression.

¹¹ Exhibit B-1, Application, PDF page 107.

¹² AEY Final Argument, PDF page 15.

34. The following table was provided by YEC to illustrate differences between forecast wholesale purchases from an AEY perspective versus a YEC perspective:

Table 3: Wholesale purchases (AEY/YEC perspectives)

	YEC Forecast	AEY Forecast	Variance (AEY-YEC)	Year over Year growth (AEY)	Year over Year growth (YEC)
	GWh	GWh	GWh	(%)	(%)
2022A	346.3	346.3	-	-	-
2023F	351.3	349.7	-1.6	1.0	1.4
2024F	355.9	362.6	6.7	3.7	1.3

Source: Table prepared from information provided in YEC Final Argument, PDF page 7.

35. YEC submitted that its own forecast annual increase in wholesales (sales to AEY) of 1.3 to 1.4 per cent is in line with historical averages and added that 2023 year-to-date actuals closely align with the 2023 YEC forecast. YEC said it was unable to confirm as reasonable the 2024 growth forecast by AEY and concluded by stating that it forecasts Fish Lake hydro generation at 8.7 GWh for each test year equal to the long-term average (LTA), as required by OIC 2021/16. It based its Fish Lake hydro generation forecast on 2021-2022 output, planned maintenance, and water availability. In addition, YEC stated that it adjusted this forecast for any planned decreases in generation due to capital rebuilds.¹³
36. YEC noted the following with respect to its forecast of purchase power:
- The 2023 year to date actuals closely align with YEC's forecast (YEC GRA forecast 351.3 GWh versus AEY forecast of 349.7 GWh and the YEC current full year forecast of 351.2 GWh).
 - The 2024 forecast for YEC shows sustained growth at 1.3 per cent (versus 1.4 per cent the previous year). In contrast, the AEY 2024 forecast shows a major growth increase at 3.7 per cent, and YEC has not been able to confirm the resulting 6.7 GWh forecast difference as reasonable.¹⁴
 - AEY population growth assumptions are more optimistic than that set out in the Yukon Outlook, the Government of Yukon's fiscal and economic forecast from March 2023.¹⁵
 - Increases in microgeneration will reduce wholesale purchase from YEC.

¹³ YEC Final Argument, PDF pages 6-8.

¹⁴ YEC Final Argument, PDF page 7.

¹⁵ YEC Final Argument, PDF page 7, footnote 12. Also referenced as AEY-UCG-018 (a) Attachment 1, starting at PDF page 262.

- Variance in forecast hydro-generation production from AEY facilities accounts for some variance and the long-term average hydro-generation production from the AEY Fish Lake facility has not been confirmed.

2.2.3 Reply of AEY

37. AEY responded to YEC's comments by stating that the wholesale purchase forecast it provided in its GRA is a reasonable estimate of wholesale purchases from YEC. It also noted that AEY's sales are tracking approximately 0.8 per cent lower than forecast and AEY's primary wholesale forecast for 2023 is approximately 0.5 per cent lower than YEC's forecast. For 2024, AEY submitted that its forecast was 1.8 per cent higher than YEC's forecast.

2.2.4 Board Findings

38. The Board accepts the 2023 full-year forecast of power purchases (351.2 GWh) as provided by YEC because the Board considers the YEC's current (2023) full-year forecast as the most accurate for the 2023 test year. AEY is directed to use this amount for its forecast purchase power and is directed to reflect such in its compliance filing to this Board Order. Further, AEY is directed to adjust its forecast of other supply options to reflect the level of power purchases as reflected in this decision. That is, AEY is to adjust its other supply options but not the level of its sales forecast.
39. The Board notes that, for 2024, AEY and YEC have provided materially different forecasts for "Wholesales" (wholesale sales by YEC and wholesale purchases by AEY). The first mention of wholesales from YEC came in Final Argument. YEC did not ask any IRs on the AEY application, nor did YEC test the wholesales forecast during the oral public hearing. The YEC forecast looks at historical averages. Further, at the time of this decision, the YEC application was still in process and the Board has not made any determinations on the reasonableness of the YEC wholesales forecast. Because the 2024 wholesale forecasts are materially different, the Board does not accept the YEC submission on "Wholesales" because the YEC forecast has not been fully tested at the time of this decision and the Board finds that the approach taken by AEY in its forecast to be superior to an approach of looking at historical averages.
40. For the reasons set out above, for 2024, the Board finds the purchase power forecast by AEY to be reasonable and accepts the forecast as filed by AEY.

3 Fuel costs

3.1 Views of AEY

41. AEY provided the following for its forecast fuel costs:

Table 4: AEY Fuel costs (\$000)

	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals							Test Period	
Fuel Costs	5,363	5,571	5,403	5,432	5,709	5,353	5,766	9,181	9,023
Litres (000)	5,655	5,877	5,783	5,812	5,890	5,725	5,872	5,738	5,759

Source: Exhibit B-1, Application, Table 4.1, PDF page 111.

42. AEY stated that the reason for increases in fuel costs for the test period is mainly due to higher fuel prices.
43. Fuel purchases (and prices) are determined through a diesel fuel tendering process for each of the five isolated diesel plants operated by AEY. In addition to the isolated plants, AEY has standby units at Carmacks, Teslin, Haines Junction, Ross River, Pelly Crossing, and Stewart Crossing. Fuel costs are a function of forecast sales, line losses, plant efficiencies, and delivered fuel prices.¹⁶

3.2 Views of interveners

44. Parties did not make any comments on fuel prices.

3.3 Board Findings

45. The Board notes that the evidence tendered by AEY on fuel costs is uncontroverted. The Board has reviewed AEY's evidence on fuel costs and finds the fuel price amounts as provided by AEY to be reasonable. Accordingly, the Board approves AEY's fuel price forecast as applied for. In addition, the Board notes that any variances from the fuel price forecast are trued-up through a future Rider F adjustment.

¹⁶ Exhibit B-1, Application, PDF pages 111-112. Line losses are calculated based on a 5-year average. Plant efficiencies are based on the average efficiencies of the previous 5 years and adjusted for any changes due to replacement of units. Fuel prices are based on April 2023 actual prices for diesel fuel.

4 Operations and maintenance (O&M) expense (excluding fuel costs)

4.1 Overview

46. The costs for any O&M expense not addressed specifically by the Board are approved.
47. For 2023-2024, AEY requested approval of labour and non-labour O&M expenses (excluding fuel costs) totalling \$14.500 million and \$14.755 million, respectively. The following table shows actual, approved, and forecast O&M amounts by function for the years 2016-2024:

Table 5: Summary of total labour and non-labour O&M expenses (excluding fuel costs) Actual, Test Period forecast and Approved by function (\$000)

Description	Actuals							Test Period		Approved	
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2016	2017
Production	2,129	2,320	2,274	2,114	1,882	2,569	3,107	3,376	3,096	2,048	1,980
Distribution	2,972	3,217	2,936	3,189	3,254	4,250	4,481	4,134	4,190	3,248	3,314
General	217	303	207	255	281	429	520	370	378	233	234
Public Information	94	191	58	74	84	156	249	179	186	135	153
Customer Accounting	2,017	1,952	2,060	1,991	2,176	1,964	2,168	2,485	2,842	2,163	2,208
Administration and General	3,712	3,900	3,578	3,481	4,289	4,445	4,268	3,956	4,063	3,804	3,866
Total O&M Expenses	11,141	11,883	11,113	11,104	11,966	13,814	14,794	14,500	14,755	11,630	11,754

Source: Exhibit B-10.1, AEY GRA Schedules, Omissions& Updates – Blackline, S 5.1

48. In its evidence, AEY stated that since the time of its last 2016-2017 GRA, it had been successful in spending within its last approved forecasts. It asserted that, with the exception of increases expected in its Customer Accounting cost category due to the proposed CCS client billing program annual subscription fee,¹⁷ O&M expense increases were largely due to inflation.¹⁸ As stated during the oral hearing by Ms. E. Rogers, Director, Regulatory, for AEY:

I think the — the exercise of — of measuring efficiencies in itself is not efficient. So it is a bit challenging to do so. But we do look at things — like, again, if we took 2017 costs and applied the inflation as what per the Stats Canada inflation rates, we would come into an O&M forecast for 2024 around \$14.6 million. We're coming in with a forecast in the test period with a 14.9 million O&M forecast, and that incorporates a \$700,000 increase for CCS costs. So the differential between those two can kind of be assumed that, you

¹⁷ Exhibit B-4, AEY Consolidated IR Responses, AEY-JM-018, PDF page 50; AEY-JM-019, PDF page 51.

¹⁸ Transcript, Volume 1, PDF pages 76-77.

know, as costs are inflating we are also becoming efficient as we — time goes on and we find process, improvements and things like that.¹⁹

4.2 Views of interveners

49. The UCG put forward that AEY failed during questioning, to identify any efficiencies it has achieved in order to maintain costs, and recommended that the Board decrease AEY's O&M costs by five per cent "to give AEY an incentive to establish efficiencies going forward."²⁰
50. Mr. Maissan stated that AEY has been able to "manage their O&M costs to within the \$11 million to \$12 million range from 2012 through 2020."²¹ He further argued that AEY is well positioned to manage its 2023-2024 costs stating that, in 2016-2017, AEY was approved for lower-than-applied-for O&M costs and was able to incur, on average, costs below those approved four years.
51. Mr. Maissan pointed to AEY's record with brushing costs where, given the flexibility that AEY has shown in gaining efficiencies during a year, lower costs in subsequent years should be expected. Having theorized that other O&M costs could benefit from similar flexibility and efficiency gain, Mr. Maissan recommended that the Board reduce AEY's applied-for O&M costs by \$0.500 million in each of 2023 and 2024.²²
52. In reply to the UCG, AEY argued that the evidence clearly shows AEY has been able to find efficiencies in its operations as demonstrated by the fact its 2017 O&M costs, when adjusted for inflation and in consideration of the ATCO CIS costs, remain in line with what has been forecast for 2023-2024. Further, in its reply argument, AEY contended that Mr. Maissan's recommendation that the Board reduce AEY's applied-for O&M costs by \$0.500 million in each of the test years was not supported by the evidence on the record and the reduction appeared to be arbitrary. AEY referred to climate change in relation to brushing costs and did not address Mr. Maissan's point related to efficiencies in general.

¹⁹ Transcript, Volume 1, PDF pages 76-77.

²⁰ UCG Final Argument, paragraphs 33-34, PDF page 7.

²¹ Maissan Final Argument, PDF pages 10-11, referring to Exhibit B-4, Consolidated IR responses, AEY-JM-015.

²² Maissan Final Argument, PDF pages 10-11.

4.3 Key assumptions and FTE's

4.3.1 Views of AEY

53. In its Application, AEY forecast a 2024 year-end employee complement of 76.26 full-time equivalents (FTEs).²³ This was an increase of 8.13 FTEs over the approved 2017 complement of 68.13 FTEs.
54. During the oral hearing, AEY clarified that its actual 2022 complement (excluding 2022 vacancies of 3.31 FTEs) was 65.49 FTEs and that, as of the date of the hearing, there were two full-time positions forecast to be hired in 2023 that remained vacant.²⁴
55. AEY also provided information respecting the key assumptions used in its application, which are summarized in the following table:

Table 6: Summary of key assumptions forecast for 2023-2024 (%)

	2023	2024
In-scope labour inflation	2.00	2.50
Out-of-scope labour inflation	2.90	2.50
Other inflation	3.80	2.50
Vacancy rate	3.65	3.65
Long term debt rate	4.56	4.56

Source: Exhibit B-1, Application, Table 1.4 – Key Assumptions, PDF page 14.

56. For 2023, AEY's in-scope labour costs, which are subject to a Collective Agreement, were escalated by 2.00 per cent based on the agreement expiring December 31, 2023. AEY's out-of-scope labour costs, which are not subject to a Collective Agreement, were escalated by 2.90 per cent — consistent with increases approved in Alberta. For 2024, both in-scope and out-of-scope labour costs were escalated by 2.50 per cent — consistent with increases applied-for and approved in Alberta for 2024.
57. Non-labour costs were escalated by 3.8 per cent and 2.5 per cent for 2023 and 2024, respectively, based on the 2023-24 Fiscal and Economic Outlook published by the Government of Yukon in March 2023.
58. AEY applied a vacancy rate of 3.65 per cent, or approximately three FTEs, to reduce its forecast labour expenses for the 2023-2024 test period. The 3.65 per cent vacancy rate was based on a five-year historical averaging methodology consistent with the methodology previously approved by the Board.

²³ Exhibit B-1, Application, Table 1.4 FTEs, PDF page 16.

²⁴ Transcript, Volume 3, PDF page 21. AEY response to Undertaking 6: The full-time positions that remained vacant were Team Lead Plant and Electric Engineer.

4.3.2 Board Findings

59. While long term debt, might be expected to come under Section 4, the Board's analysis will be set out in Section 6 which addresses Return on Rate Base.
60. The Board accepts AEY's in-scope and out-of-scope labour and other inflation escalation percentages and vacancy rates, having found the forecast reasonable and consistent with previous Board-approved methodologies.
61. The Board finds that the labour costs respecting the two forecast FTE positions that remained vacant in December 2023 should not be included in AEY's 2023 O&M forecast.
62. For the year 2023, AEY is directed to remove the forecast labour costs associated with those FTEs in its compliance filing. AEY may include prorated costs for these two FTEs in its 2024 O&M forecast if AEY confirms that these positions have been filled at the time of its compliance application to this Board Order. If these positions have not been filled at that time, the Board directs AEY to remove the forecast labour costs associated with them in its 2024 O&M forecast.

4.4 Views of AEY- Non-labour O&M – Public Information

4.4.1 Account 70100 - Public Information Administration

63. With respect to certain costs recorded in Account 70100 – Public Information Administration, in its response to AEY-YUB-017(a), AEY confirmed that it had previous Board approval for the recovery of costs related to the “sponsorship of community events.”²⁵ These types of costs caused increases of \$0.050 million and \$0.063 million in the years 2021 and 2022, respectively.
64. Sponsorship was explored further during the oral hearing. When asked for clarification of whether AEY's sponsorship of community events was properly a corporate sponsorship paid by the shareholder or whether costs were being recovered through rates, AEY responded that:

So sponsorship, yeah, we've sponsored a number of events in the community for many years, rendezvous and bike relays and events around the community. Community-centered events, so not so much -- there's no sporting events or things like that that we sponsor. To date, those have been in revenue requirement in that account that is noted there. There's been -- it's been in place for a very long time.²⁶

²⁵ Exhibit B-4, AEY Consolidated IR responses, AEY-YUB-017(a), PDF page 1089.

²⁶ Transcript, Volume 3, PDF page 70.

65. A further AEY explanation indicated:

Included in revenue requirement would be what we view as sort of a marketing expense as far as having our name at events and building customer relationships within the communities. Not included are the explicit donations, charitable or otherwise, to organizations. Those are on the shareholders' cost.²⁷

66. When asked, AEY did not provide a reference to any past Board Order or explicit approval for sponsorship costs but responded that costs of the nature being discussed were components of the forecast put forward and approved in revenue requirement.

4.4.2 Board Findings

67. Although AEY's Guidelines and Limitations on Sponsorships, as provided pursuant to an undertaking, appears to identify organizations and activities not eligible to receive funding, the comments of AEY during the oral hearing provide a different interpretation of what constitutes an ineligible cost. When asked what proportion of revenue requirement is related to "giving back to the community" as compared with public information that is of benefit to customer safety or similar, AEY responded that it was approximately \$0.005 million.²⁸
68. Notwithstanding the boundaries provided by the guideline, it appears to the Board that certain ineligible costs still flowed through to revenue requirement. Furthermore, based on the information provided by AEY, it is not clear that the Board has previously given explicit approval for AEY to recover through its revenue requirement, any costs related to the sponsorship of community events.
69. The Board finds that it is not reasonable for AEY to recover any costs related to the sponsorship of community events by way of having its name at events and building customer relationships within the community through its revenue requirement. The Board considers these costs are clearly for the account of the shareholder and, as non-regulated costs, do not rightly belong within a rate regulated revenue requirement.
70. The Board directs AEY, in its compliance filing to this Board Order, to remove all costs from its 2023-2024 revenue requirement that are linked to any sponsorship of community events which, at the time of the oral hearing, AEY estimated to be in the amount of \$0.005 million in Account 70100. As the Board considers these costs to be non-regulated, it directs AEY, in this and each future GRA, to provide assurance that

²⁷ Transcript, Volume 3, PDF page 71.

²⁸ Transcript, Volume 3, PDF page 124.

these costs have not been included within any account or cost category of AEY's revenue requirement.

4.4.3 Account 70200 – General Public Information

71. Within its non-labour costs for Account 70200 - General Public Information, AEY's forecast of increased costs in 2023 related to updating its communication material, video costs, notification of billing system changes, and updating design and images on the AEY website. These activities resulted in a significant increase in 2023 costs (\$0.070 million) compared to 2022 (\$0.020 million).²⁹
72. However, AEY did not provide reasons supporting a similar level of spending forecast for 2024 (\$0.072 million).
73. Similarly, in its response to AEY-JM-016, which sought justification for the overall cost increases requested for the Public Information function, AEY, again, only addressed costs in support of \$0.050 million of additional costs in 2023, and not 2024.³⁰

4.4.3.1 Board Findings

74. The Board finds that AEY has not supported its 2024 non-labour forecast costs in Account 70200 General Public Information. Given that the costs incurred in 2023 appear to be one-time in nature, and applicable only to the year 2023, the Board finds AEY's 2024 forecast of \$0.072 million to be unreasonable. The Board directs AEY, in its compliance filing to this Board Order, to remove \$0.050 million from its 2024 forecast non-labour costs in Account 70200 - General Public Information. The resulting \$0.022 million is in line with AEY's actual 2022 Account 70200 General Public Information expenditures.

4.5 Views of AEY - Non-labour O&M – Account 72100 - Administrative

75. AEY 2023-2024 Administration & General function is comprised of eight distinct accounts: Administrative (Account 72100), Administrative Corporate (Account 72200), Insurance (Account 72300), Injuries and Damages (Account 72400), Employee Expenses (Account 72500), Training and Safety (Account 72600),

²⁹ Exhibit B-10.3, AEY GRA Schedules, Omissions & Updates, Schedule S5.2, Line nos. 236-237.

³⁰ Exhibit B-4, AEY Consolidated IR Responses, AEY-JM-016, PDF pages 46-47. Incremental costs to be incurred in 2023 were identified as: communication material and video costs for 'understanding your bill campaign' (\$25,000); communication costs for graphic design and mailing for new billing system notification (\$10,000); and graphic design and photography costs for all images on AEY website (\$15,000).

Relocation (Account 72700), and Audit/Legal Fees & Special Studies (Account 72900).

76. In this sub-section, the Board examines costs specific to Account 72100 – Administrative within AEY’s overall Administration & General function.

Table 7: Breakdown of Account 72100 – Administrative (labour and non-labour), Actual (A) and Forecast (F) costs 2016-2024 (\$000)

	2016A	2017A	2018A	2019A	2020A	2021A	2022A	2023F	2024F
Total labour costs	612	684	722	648	678	997	767	867	878
Non-labour costs									
Head office services	642	721	573	614	597	567	359	818	904
IT charge	290	393	325	294	325	354	419	472	472
IT services	160	162	163	165	140	145	162	173	179
Contract services & consultants	96	162	166	272	249	274	208	276	278
Telephone	35	54	57	54	58	62	79	86	89
Travel	105	97	78	53	36	43	47	78	79
IT termination	-	-	-	-	467	-	-	-	-
IT transition costs	-	-	-	-	-	294	-	-	-
Severance – Covid vaccine policy	-	-	-	-	-	-	410	-	-
Other	109	115	111	93	98	75	129	67	89
Total non-labour*	1,437	1,704	1,473	1,546	1,969	1,814	1,813	1,970	2,090
Less anomalous costs: IT termination, IT transition and severance	-	-	-	-	(467)	(294)	(410)	-	-
Total non-labour net of anomalous costs	1,437	1,704	1,473	1,546	1,502	1,520	1,403	1,970	2,090
Forecast per cent increase to 2022A								41%	49%

Source: Exhibit B-4, AEY Consolidated IR responses, AEY-YUB-019(a), PDF page 1094.* The balance of this table was prepared by the Board.

77. As shown in the table above, after removing three anomalous cost categories, AEY’s forecast non-labour Administrative costs for 2023-2024 have increased by 41 and 49 per cent, respectively, compared to 2022. Most of these non-labour cost increases are shown to be in the sub-category of Head Office services. Costs charged under this category are detailed in the table below:

Table 8: Breakdown of Account 72100 – Administrative - Head office services (non-labour) Actual (A), F Forecast (F) and Approved (Appr) costs 2016-2024 (\$000)

	2016A	2017A	2018A	2019A	2020A	2021A	2022A	2023F	2024F	2016 Appr	2017 Appr
Governance, HR, and Health & Safety	31	112	127	127	127	113	118	121	112	149	149
Rates and Terms & Conditions	-	-	-	-	-	-	-	-	-	40	40

Financial Reporting and Regulatory Support	456	494	413	427	410	397	241	697	792	554	565
Payroll, Use of Systems and IT	155	115	8	4	7	-	-	-	-	114	116
General Marketing	-	-	25	52	52	57	-	-	-	-	-
Total Head Office services	642	721	573	614	597	567	359	818	904	854	870
Per cent (decrease) to 2016 approved	(25%)										
Per cent (decrease) to 2017 approved		(18%)	(35%)	(30%)	(32%)	(35%)	(59%)				
Forecast per cent increase to 2022A								128%	152%		

Source: Exhibit B-10.3, AEY 2023-2024 GRA Regulatory Schedules - Blackline, S5.3 – Affiliate Charges in Operations and Maintenance Expenses, per cent calculations added by Board.

78. When asked in AEY-YUB-020 to provide reasons for the increases in 2023-2024 Financial Reporting and Regulatory Support costs compared to the years 2016-2022, AEY combined its response with its response to a second question seeking general explanations for the costs incurred in 2016-2022.³¹ AEY's response resulted in a mix of explanations related to increased workload and labour costs, high turnover and vacancies in the Financial Reporting group in combination with what appeared to be labour costs being incurred in the Regulatory group outside of the Whitehorse office.
79. For example, AEY noted that the "Corporate Accountant position that was previously based in Whitehorse was back-filled in Head Office when that position became vacant." When asked, AEY clarified during the oral hearing that the Corporate Accountant position was filled from the Edmonton office.³²

4.5.1 Board Findings

80. The Board finds the information provided by AEY unhelpful in determining if its 2023-2024 forecast non-labour Financial Reporting and Regulatory Support costs (\$0.697 million and \$0.792 million, respectively) are reasonable. It is unclear whether the increased costs were attributable to labour costs within its Whitehorse office or non-labour affiliate costs provided outside its Whitehorse office. This is concerning, as AEY's regulatory schedules show that costs identified as "Financial Reporting and Regulatory Support" appear within Schedule S5.3 as "Affiliate Charges included in Operations and Maintenance Expense."
81. The Board further finds that the variance explanations noting cost increases or cost variances in these Affiliate Charges cannot be supported by any explanations related

³¹ Exhibit B-4, AEY Consolidated IR responses, AEY-YUB-020, PDF pages 1097-1098.

³² Transcript, Volume 3, PDF page 76.

to labour costs, high turnover, and vacancies, given that Financial Reporting and Regulatory Support are outside AEY's labour costs for this cost category; they are incurred as an Affiliate Charge and recorded as non-labour costs in AEY's regulatory schedules.

82. Furthermore, AEY did not provide satisfactory explanations for why, during the years 2016-2022, it spent significantly less than its approved 2016-2017 affiliate amounts yet anticipates a 300 per cent cost increase over the test period when compared to 2022.
83. For these reasons, the Board does not accept AEY's 2023-2024 forecast Financial Reporting and Regulatory Support costs. The Board finds it reasonable to hold AEY's 2023-2024 forecast Financial Reporting and Regulatory Support costs to an amount equal to an average of its previous seven years' actual costs incurred for this cost category. Accordingly, the Board directs AEY to use a forecast for its Financial Reporting and Regulatory Support costs for the years 2023 and 2024 in the amount of \$0.406 million in its compliance filing to this Board Order.³³

5 Depreciation expense

84. On September 11, 2023, approximately two months after the submission of its GRA application,³⁴ AEY filed a comprehensive 2022 Depreciation Study³⁵ dated September 2023 prepared by Larry Kennedy of Concentric Advisors, ULC (Concentric). AEY proposed the adoption of the Concentric report which included Mr. Kennedy's depreciation parameter recommendations and their use as informing the depreciation rates and depreciation expense calculations therein, for the 2023-2024 test years. On October 30, 2023, AEY submitted a revised Concentric report and updates to certain IR responses on depreciation.
85. AEY's 2023-2024 forecast depreciation expense is summarized in the following table:

Table 9: Summary of historical actual (A) and forecast (F) depreciation expense by category

	2021A	2022A	2023F	2024F
	(\$ millions)			
General provision – life	7.530	7.958	7.553	9.395
Amortization of reserve differences - life	(0.402)	(0.402)	(0.684)	(0.684)
General provision – net salvage	n/a	n/a	1.336	1.430

³³ Calculated as \$(0.456+0.494+0.413+0.427+0.410+0.397+0.241) million / 7 = \$0.406 million.

³⁴ At the time of its July 7, 2023 GRA application, AEY's Depreciation study was not complete. AEY intended to submit its depreciation study and an application update by late August or early September 2023.

³⁵ The Depreciation Study calculated annual depreciation accrual rates applicable to electric hydro and diesel generation, distribution, and general plant in service as of December 31, 2022.

Amortization of reserve differences – net salvage	n/a	n/a	0.670	0.670
Vehicle depreciation capitalized - life	(0.178)	(0.211)	(0.211)	(0.215)
Total depreciation expense (GRA S7.1)	6.950	7.343	8.664	10.596
Amortization of contributions (GRA S8)	(1.877)	(2.033)	(2.077)	(2.389)
Net depreciation expense	5.073	5.310	6.587	8.207

Source: Exhibit B-10.3, GRA regulatory schedules – omissions and updates - blackline, S7.1 and S8.

86. With respect to the increase in total depreciation expense between the years 2022 and 2023, in its response to depreciation-related information requests (IRs), AEY identified the following factors as causing the increase in depreciation expense:

Table 10: Factors causing the increase in 2023 forecast depreciation expense compared to 2022 actual

Factors causing increase (decrease) in depreciation expense	Amount (\$ millions)
Increase in depreciation expense – life due to increases in capital	0.911
Decrease in depreciation expense – life, due to changes in proposed average service lives	(0.818)
Decrease in depreciation expense – life, due to provision for amortization of reserve differences	(0.186)
Decrease in depreciation expense – life, due to refund of over-amortization of DSM program costs	(0.563)
Sub-total reduction in depreciation expense due to average service life	(0.656)
Increase in depreciation expense – net salvage, due to proposed net salvage per cents	1.338
Increase in depreciation expense – net salvage, due to the provision for amortization of reserve differences	0.670
Sub-total increase in depreciation expense due to net salvage	2.008
Total increase in depreciation expense before contributions	1.352

Source: Exhibit B-3.1, 2023-2024 GRA schedules updated for depreciation study, S7.1 total increase in depreciation expense calculated as 2023 depreciation expense \$8.695 million less 2022 depreciation expense \$7.343 million = \$1.362 million; Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-001(a), PDF page 4; AEY-YUB-2-002(b), PDF pages 32-33. Note that the details provided in Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-001(a), and AEY-YUB-2-002(b) were not revised to reflect the changes submitted by AEY in its October 30, 2023 omissions and updates.

5.1 Overview

87. Depreciation expense represents the return of AEY's capital investment in utility assets over the period in which the assets are used to provide service to ratepayers. This time frame equates primarily to the average service life of a given group of assets, and is determined, among other things, during the course of examining a depreciation study such as the one prepared and submitted by Concentric on behalf of AEY in its 2023-2024 GRA.
88. The Concentric depreciation study recommended depreciation parameters respecting average service life and Iowa curve (life-curve) and net salvage per cent estimates. The parameters were developed based on: a traditional retirement rate analysis and net salvage study in combination with the use of professional judgement; staff interviews and site tours; consideration of current Government

energy transition policies; and the amortization periods and service lives used by other utilities. The depreciation rates that resulted from the proposed parameters, were based on the straight-line, whole-life method using the equal-life group procedure,³⁶ all of which are methodologies consistent with those used by AEY and Mr. Kennedy in previous depreciation studies Mr. Kennedy had authored.

89. Currently, AEY has Board approval to use the “amortization of reserve differences” mechanism where, on a group-asset-account basis, any life- or net-salvage related depreciation variances that exceed five per cent of the theoretical accumulated depreciation balance are amortized over the composite remaining life of that group of assets (limited to no less than three years).³⁷ This mechanism allows AEY to refund to, or collect from ratepayers any differences between what should have been collected in depreciation expense on a theoretical basis and what has been collected on an actual basis. AEY confirmed that its current process is to refund or collect any amortization of reserve differences as a dollar amount adjustment to depreciation expense as opposed to reflecting the reserve difference as a component of either a life or net salvage depreciation rate.³⁸
90. In Board Order 2009-2 (taking effect in the year 2008), and again in Board Order 2014-06, the Board denied the pre-collection of net salvage costs through AEY’s depreciation expense. In Appendix A to Board Order 2009-2 — Reasons for Decision, on PDF page 24, the Board directed AEY to “inform the Board and interested parties when the balance for this liability account reaches \$2 million.”
91. In the current application, AEY forecast that the net salvage reserve account would be well below the \$2 million threshold established by Board Order 2009-2 unless the Board re-instated the pre-collection of future negative net salvage costs commencing in 2023. AEY submitted that the current net salvage reserve account balance is not sufficient to fund planned salvage costs over the next several years.³⁹ Accordingly, AEY and Centric recommended the re-instatement of the pre-collection of future net salvage costs (which consists of gross salvage proceeds less costs to remove an asset from service)⁴⁰ based on the net salvage per cents estimates as determined in a traditional net salvage study. AEY’s proposal to re-instate the pre-collection of negative net salvage costs includes a simultaneous re-instatement of the use of the amortization of reserve differences mechanism for net salvage.

³⁶ Exhibit B-3.2, Attachment 1, 2022 Depreciation Study Report, PDF pages 6 and 10.

³⁷ Exhibit B-3.2, Attachment 1, 2022 Depreciation Study Report, PDF page 40.

³⁸ Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-001(m), PDF page 7.

³⁹ Exhibit B-1, AEY 2023-2024 application, paragraph 5, PDF page 125.

⁴⁰ Negative net salvage costs and the associated net salvage reserve (liability) account was previously identified as “Future Removal and Site Restoration” rather than “net salvage.”

92. In response to AEY-YUB-2-001(e) Attachment 1, AEY provided its actual 2007-2022 and forecast 2023-2024 transactions and year end balances in its net salvage reserve account, commencing with the year 2007.

Table 11: AEY 2007-2022 actual (A) and 2023-2024 forecast (F) negative net salvage⁴¹ reserve account (\$ millions)

	Opening balance	Removal costs (recovered)/incurred	Removal costs pre-collected in depreciation expense	Closing balance
2007A	(4.051)	(0.040)	(0.598)	(4.689)
2008A	(4.689)	(0.025)	-	(4.714)
2009A	(4.714)	0.030	-	(4.684)
2010A	(4.684)	0.118	-	(4.566)
2011A	(4.566)	0.062	-	(4.504)
2012A	(4.504)	0.055	-	(4.449)
2013A	(4.449)	0.230	-	(4.219)
2014A	(4.219)	0.483	-	(3.736)
2015A	(3.736)	0.044	-	(3.692)
2016A	(3.692)	0.223	-	(3.469)
2017A	(3.469)	0.183	-	(3.286)
2018A	(3.286)	0.440	-	(2.846)
2019A	(2.846)	0.688	-	(2.158)
2020A	(2.158)	0.497	-	(1.661)
2021A	(1.661)	0.310	-	(1.351)
2022A	(1.351)	0.874	-	(0.477)
2023F	(0.477)	1.000	(2.008)	(1.485)
2024F	(1.485)	1.264	(2.103)	(2.324)

Source: Exhibit B-6.1, AEY Round 2 IR responses, AEY-YUB-2-001(e) Attachment 1.

93. In its October 24, 2023 responses to depreciation IRs, AEY identified several errors⁴² in its application that required correction, including errors in the Concentric depreciation study. On October 30, 2023, AEY submitted the revised Concentric depreciation study and updated certain earlier IR responses.⁴³

⁴¹ Also referred to as Future Removal and Site Restoration costs or reserve account.

⁴² Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-001(b)(e)(n), PDF page 4, 5 and 8; AEY-YUB-2-004(b)(c), PDF page 48; AEY-YUB-2-005(c), PDF page 51; AEY-YUB-2-006(b), PDF page 260-261; AEY-YUB-2-015(b-d), PDF page 277; AEY-YUB-2-016(a), PDF page 279; AEY-YUB-2-022(b), PDF page 302. Exhibit B-8, AEY-UCG-2-001(b), PDF page 2; AEY-UCG-2-002(b-c), PDF pages 5-6.

⁴³ Exhibit B-10 to Exhibit B-10.4, AEY updates to 2023-2024 General Rate Application, October 30, 2023.

5.2 Average service life and Iowa curve

5.2.1 Views of AEY

94. Concentric recommended life-curve changes to 21 of AEY's 34 depreciation study accounts. This included the addition of a newly established Account 347.20 – Production – Diesel – Renewables Energy Storage.
95. The most significant changes in life-curve estimates were to AEY's distribution plant asset accounts. The recommendations were primarily lengthening of average service life for five⁴⁴ of the 13 distribution accounts. Reasons provided by Concentric for the proposed increase in service lives included a better mathematical or visual fit of the actuarial data to the recommended life-curve, discussions with AEY operational and management staff indicating field observations consistent with the retirement rate analysis, review of peer Canadian utilities, and the use of Mr. Kennedy's experience and professional judgement. In response to AEY-YUB-2-001(n)(iii), AEY confirmed that, with respect to the five distribution accounts for which lengthened service lives were proposed, its "robust maintenance program has extended the asset life these accounts longer than previously expected."⁴⁵
96. Given that lengthening average service lives generally result in lower depreciation rates, these five accounts make up approximately 48 per cent of the cost of AEY's total depreciation study assets and would comprise the majority of the \$0.818 million reduction⁴⁶ to depreciation expense - life noted in Table 10 above.
97. Concentric proposed shortened average service lives for three⁴⁷ production plant asset accounts and lengthening average service lives for two⁴⁸ production plant asset accounts. Reasons provided by Concentric for the proposed changes were similar to the rationale used in Concentric's distribution plant analysis. These five, of a total of 11, production accounts comprised approximately five per cent of the cost of AEY's total depreciation study assets.

⁴⁴ Distribution accounts (lengthened average service lives): Account 364.00 - Poles, towers and fixtures; Account 365.00 – Overhead conductors and devices; Account 365.10 – Overhead services; Account 367.00 – Underground conductor and devices; Account 367.10 – Underground services.

⁴⁵ Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-001(n)(iii), PDF page 9.

⁴⁶ Exhibit B-7, AEY Round 2 IR responses, AEY-JM-2-002(a), PDF page 2.

⁴⁷ Production accounts (lengthened average service lives): Account 331.00 – Structures and improvements; Account 332.00 – Reservoirs, dams and waterways; Account 334.00 Accessory electric equipment.

⁴⁸ Production accounts (shortened average service lives): Account 335.00 – Miscellaneous power plant equipment; 342.20 – Internal combustion – fuel holders, producers and accessories.

98. Concentric’s other life-curve recommendations were primarily modifications to only the lowa curve parameter.
99. No intervening party provided comments on AEY’s proposed life-curve parameters.

5.2.2 Board Findings

100. Based on its examination of the evidence provided by AEY and Concentric, and the responses to IRs, the Board finds that AEY’s proposed life-curve parameters are reasonable and have incorporated all relevant and pertinent factors applicable to AEY and the conditions under which AEY’s assets are used and maintained. The Board approves AEY’s life-curve recommendations for all accounts.
101. AEY is directed to implement the life-curve parameters in its compliance filing. The proposed and approved life-curve parameters have been summarized by the Board in Appendix 1.

5.3 Net salvage

5.3.1 Views of AEY

102. As noted earlier, AEY and Concentric recommended the re-instatement of the pre-collection of future net salvage costs (which consists of gross salvage proceeds less costs to remove an asset from service)⁴⁹ based on the net salvage per cent estimates as determined in the traditional net salvage study. AEY’s proposal includes a simultaneous re-instatement of the use of the amortization of reserve differences mechanism for net salvage.
103. Under a traditional net salvage methodology, if the Board were to approve AEY’s re-instatement of the pre-collection of future negative net salvage costs at the net salvage per cents requested, the total increase to depreciation expense is as follows:

Table 12: AEY 2023-2024 forecast net salvage costs included in depreciation expense

	2023F	2024F
	(\$ millions)	
Net salvage expense resulting from proposed net salvage per cents	1.336	1.430
Net salvage expense resulting from the provision for amortization of reserve differences – net salvage	0.670	0.670
Total increase in depreciation expense due to the re-instatement of the pre-collection of future negative net salvage costs	2.006	2.100

Source: Exhibit B-10-3, 2023-2024 GRA Schedules, Omissions & Updates, S7.1, lines 4 and 5.

⁴⁹ Negative net salvage costs and the associated net salvage reserve (liability) account was previously identified as “Future Removal and Site Restoration” rather than “net salvage.”

104. During the 2023-2024 test years, AEY expected its net salvage reserve account to be less than the \$2 million threshold set out in Appendix A to Board Order 2009-2 — Reasons for Decision, PDF page 24. In that Board Order, the Board directed AEY to “inform the Board and interested parties when the balance for this liability account reaches \$2 million.”
105. AEY provided additional rationale for its request to re-commence in 2023, the pre-collection of negative net salvage costs through its depreciation expense as discussed below.

5.3.2 Alternatives to the traditional net salvage method for the re-instatement of the pre-collection of net salvage

106. Although AEY and Concentric recommended the use of a traditional net salvage method to estimate net salvage per cents, in response to AEY-YUB-2-001(i), a matrix of other alternative methods was examined; it included details of the workings of each alternative net salvage method, their respective pros and cons, and provided for any additional AEY comments.⁵⁰
107. AEY and Concentric rejected:
- (i) the Constant Dollar Net Salvage method,
 - (ii) the expensing of costs of removal as incurred,
 - (iii) capitalizing cost of removal to the installation cost of the replacement asset, and,
 - (iv) implementing net salvage for a specific or select group of accounts, as potential alternatives to the traditional net salvage method.

The alternative methods were characterized, among other things, as either administratively complex, as resulting in higher volatility in revenue requirement or rate instability, or as resulting in higher rate base growth.

108. In contrast to the methods being rejected, AEY and Concentric stated the traditional method is the most widely used method throughout North America, largely because it minimizes intergenerational inequity through its main characteristic of pre-collecting estimations of net salvage costs. This serves to reduce volatility in future revenue requirements at the time large net salvage costs for replacement projects are incurred.

⁵⁰ Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-001(i), Attachment 1, PDF page 30.

5.3.3 *Traditional net salvage method*

109. AEY explained that under the traditional method, the net salvage reserve account balance is built up, or funded, through net salvage estimates collected through depreciation expense, and is drawn down as costs to retire assets (net salvage costs) are incurred. Not taking steps now to build up the net salvage reserve balance through a pre-collection mechanism, with the intent of addressing costs related to site restoration and aging assets that will be retired and replaced in the future, creates intergenerational inequity. This is because the funding of those anticipated net salvage costs would be charged to future customers as opposed to current customers who are the customers using and benefitting from the assets today. It was largely for these reasons that AEY and Concentric recommended the re-instatement of the pre-collection of net salvage costs through depreciation expense.
110. During the oral hearing, AEY and Concentric confirmed that the costs of removal being recorded to the net salvage reserve account were based on applying allocation per cents to total project costs.⁵¹ These net salvage allocation per cents were based on input from technical and operational personnel at the company and considered to be a reliable source of data for the traditional net salvage study. Estimating net salvage costs based on an allocation also avoids the time and costs associated with tracking actual net salvage costs which, ultimately, may not result in improved accuracy.⁵²
111. Furthermore, under the “phase-in” approach proposed by AEY and Concentric, the net salvage per cents recommended were at the lower end of the reasonable range of the results of the traditional net salvage study for most accounts.

5.3.4 *Views of the intervenors*

112. Mr. Maissan argued that although the Board had earlier directed the pre-collection of net salvage be discontinued because the net salvage reserve account “was over collected,” a move to re-instate the pre-collection now, at a time where both O&M and capital costs were forecast to be high, will exacerbate rate impacts on ratepayers.
113. Mr. Maissan recommended that, at this time, there be efforts to mitigate the pre-collection of net salvage costs. This could be achieved by way of an approach where only half of the requested net salvage amounts should be approved by the Board in 2023-2024 and that the full net salvage amount could be set in AEY’s next GRA.

⁵¹ Transcript, Volume 4, PDF pages 60-61: AEY confirmed that “the actual costs of removal amounts showing in the net salvage study submitted in the Concentric depreciation study are based on an allocation of actual project costs between the amount that was capitalized and the amount recorded against the net salvage reserve balance.”

⁵² AEY Argument, paragraph 64, PDF page 25.

5.3.5 Board Findings

114. The Board accepts AEY's current method for estimating net salvage costs as originating with an allocation per cent applied to total actual project costs. The Board finds this allocation method to be reasonable in the circumstances of AEY, and results in efficiencies when compared to the costs associated with tracking actual incurred net salvage costs on a project-by-project basis.
115. With respect to re-instating the pre-collection of net salvage costs through depreciation expense, the Board also finds it is reasonable to address now, any intergenerational inequity concerns associated with the potential for having unfunded net salvage costs in the future. Without taking some measure of action, there may be customers who currently benefit from the use of AEY's assets who do not share in the entirety of their costs. These costs include the benefit of having the assets available for use now, as well as the costs to remove those assets from service in the future. The Board accepts that these issues are alleviated to a large degree through the re-instatement of a traditional net salvage method to pre-collect, through depreciation expense, in the expectation that future net salvage costs will be incurred. The Board considers that the alternative net salvage methods discussed have potential to produce undesirable swings in costs to ratepayers and could contribute to concerns of intergenerational inequity.
116. Accordingly, the Board approves AEY's re-instatement of the pre-collection of net salvage costs through depreciation expense on the basis of the traditional net salvage method. The applicable net salvage per cents for each account will be determined in the sub-sections which follow.
117. Given the above, the Board agrees with AEY's reply argument⁵³ and rejects the recommendation of Mr. Maissan to approve a 50 per cent reduction to AEY's applied-for net salvage amounts in 2023-2024. Furthermore, the Board finds it would be counterproductive to direct an overall cut to net salvage depreciation expense on a dollar basis. To do so may result in increased administration costs to later implement the full net salvage amount in AEY's next GRA that are based on the approval of specific net salvage per cents in this GRA.

5.3.6 Views of AEY - Net salvage per cents

118. In this sub-section, the Board proceeds with its analysis to determine if, and in what amount, the net salvage per cents should be implemented and for which accounts. The proposed and approved net salvage per cent parameters have been summarized by the Board in Appendix 1.

⁵³ AEY Reply Argument, paragraph 29, PDF page 12.

119. AEY and Concentric recommended net salvage per cents for 23 of the 34 group asset accounts. The proposed net salvage per cents ranged between “positive” 10 per cent to “negative” 50 per cent.
120. A review of the traditional net salvage study provided by AEY indicates that the data relied on encompassed retirements and cost of removal commencing as early as 1983 through to the end of 2022. During the oral hearing, AEY clarified, however, that although it had relied on the same data set as used in its 2012 depreciation study, for certain accounts, net salvage data was not readily available prior to 2004 given that the information remains stored offsite. Mr. Kennedy stated that, for the purpose of estimating net salvage per cents, it is the period of the last 10 to 20 years, that is the most relevant. The more recent information would typically be given more weight as informing net salvage per cent recommendations.⁵⁴
121. The net salvage study provided bands of data for analysis which showed three-year, five-year, and full-depth trending. Concentric also provided, on an equivalent asset account basis, the net salvage per cent information used by Canadian electric generation and distribution peers.
122. As noted by Mr. Kennedy in the depreciation study, his recommendations for a graduated phase in of net-salvage information were intended to avoid any rate-shock implications. To that end, he chose the lower end of the range of net salvage used by peers for most of AEY’s asset accounts.⁵⁵

5.3.7 Views of AEY - Account 331.00 – Generation Hydro – Structures and Improvements

123. Account 331.00 – Generation Hydro – Structures and Improvements⁵⁶ comprises approximately \$1.7 million, or 0.6 per cent of AEY’s total depreciable plant studied. During the 2013-2022 period examined, this account recorded \$0.132 million in retirements and \$0.063 million in net salvage costs. The full-depth net salvage statistic indicated an overall -47 per cent.
124. Canadian electric generation and distribution peer utilities indicated net salvage ranging from zero to -10 per cent.⁵⁷

⁵⁴ Transcript, Volume 4, PDF pages 81-84.

⁵⁵ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF pages 68-69.

⁵⁶ Exhibit B-10.1 AEY Omissions & Updates – Blackline, PDF pages 69-70, 92-93 and 191.

⁵⁷ Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-003(c) Attachment 1, PDF page 46.

125. AEY recommended implementing a net salvage of -5 per cent based on AEY's recent experience and near-term requirements, and the results of the traditional net salvage study.

5.3.7.1 Board Findings

126. Of the 10 years examined, there were three years in which retirements were recorded, and five years in which costs of removal were incurred, notwithstanding that the year 2020 shows a negative cost of removal amount. Given the limited and sporadic nature of the data provided, the Board finds there to be insufficient information to approve a net salvage per cent for this account at this time. AEY may submit further detail respecting this account for the Board to consider at the time of its next depreciation study.
127. AEY is directed to implement a net salvage of 0 per cent for Account 331.00 – Generation Hydro – Structures and Improvements, in its compliance filing to this Board Order.

5.3.8 Views of AEY - Account 332.00 – Generation Hydro – Reservoirs, Dams and Waterways

128. Account 332.00 – Generation Hydro – Reservoirs, Dams and Waterways⁵⁸ comprises approximately \$8.8 million, or 3.2 per cent of AEY's total depreciable plant studied. During the 2019-2022 period examined, this account recorded \$0.834 million in retirements and \$0.046 million in net salvage costs. The full-depth net salvage statistic indicated an overall -6 per cent.
129. Canadian electric generation and distribution peer utilities indicated net salvage ranging from zero to -25 per cent.⁵⁹
130. AEY recommended implementing a net salvage of -5 per cent based on AEY's recent experience and near-term requirements, and the results of the traditional net salvage study.

5.3.8.1 Board Findings

131. The Board is not prepared to implement a net salvage of -5 per cent as requested given the limited amount of data available in the net salvage study. Implementing a net salvage of -5 per cent results in an annual accrual of net salvage costs of approximately \$0.005 per year⁶⁰ which is significantly more than the costs of removal being incurred by AEY in all but one of the last four years.

⁵⁸ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF pages 70, 92-93 and 192.

⁵⁹ Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-003(c) Attachment 1, PDF page 46.

⁶⁰ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF page 92.

132. However, given that it appears there is a trend commencing in the years 2019-2022 of both asset retirements and costs of removal, the Board considers a net salvage of -2 per cent to be reasonable until more information is available. The annual accrual associated with a -2 per cent net salvage is approximately \$0.002 million⁶¹ and is more in line with recent annual amounts of net salvage being incurred in this account at this time.⁶²
133. AEY is directed to implement a net salvage of -2 per cent for Account 332.00 – Production Hydro – Reservoirs, Dams and Waterways, in its compliance filing to this Board Order.

5.3.9 Views of AEY - Account 333.00 – Generation Hydro – Water Wheels, Turbines and Generators

134. Account 333.00 – Generation Hydro – Water Wheels, Turbines and Generators⁶³ comprises approximately \$3.3 million, or 1.2 per cent of AEY's total depreciable plant studied. During the 2013-2022 period examined, this account recorded \$0.539 million in retirements and \$0.041 million in net salvage costs. The full-depth net salvage statistic indicated an overall -8 per cent.
135. Canadian electric generation and distribution peer utilities indicated net salvage ranging from zero to -30 per cent.⁶⁴
136. AEY recommended implementing a net salvage of -5 per cent based on AEY's recent experience and near-term requirements, and the results of the traditional net salvage study.

5.3.9.1 Board Findings

137. The Board is not prepared to implement a net salvage of -5 per cent as requested given the limited amount of data available in the net salvage study. No asset retirements or costs of removal were recorded during the years 2014-2018.
138. However, given that it appears there is a trend of asset retirements and costs of removal commencing in the years 2019-2022,⁶⁵ the Board considers a net salvage of -2 per cent to be reasonable until more information is available.

⁶¹ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF page 219, calculated as \$0.101 million * 1 per cent.

⁶² Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF page 192.

⁶³ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF pages 71, 92-93 and 193.

⁶⁴ Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-003(c) Attachment 1, PDF page 46.

⁶⁵ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF page 193.

139. AEY is directed to implement a net salvage of -2 per cent for Account 333.00 – Production Hydro – Water Wheels, Turbines and Generators, in its compliance filing to this Board Order.

5.3.10 Views of AEY - Account 335.00 – Generation Hydro – Miscellaneous Power Plant Equipment

140. Account 335.00 – Generation Hydro – Miscellaneous Power Plant Equipment⁶⁶ comprises approximately \$0.081 million, or less than 1 per cent of AEY's total depreciable plant studied. During the 2013-2022 period examined, this account recorded \$0.106 million in retirements and \$0.008 million in net salvage costs. The full-depth net salvage statistic indicated an overall -7 per cent.
141. Canadian electric generation and distribution peer utilities indicated net salvage ranging from zero to -15 per cent.
142. AEY recommended implementing a net salvage of -5 per cent.

5.3.10.1 Board Findings

143. Of the 10 years examined, there were only three years in which retirements and corresponding costs of removal were recorded. Given the limited and sporadic nature of the data provided, the Board finds there to be insufficient information to approve a net salvage per cent for this account at this time. AEY may submit further detail respecting this account for the Board to consider at the time of its next depreciation study.
144. AEY is directed to implement a net salvage of 0 per cent for Account 335.00 – Generation Hydro – Miscellaneous Power Plant Equipment, in its compliance filing to this Board Order.

5.3.11 Views of AEY - Account 341.20 – Generation Diesel – Internal Combustion Structures

145. Account 341.20 – Generation Diesel – Internal Combustion Structures⁶⁷ comprises approximately \$6.1 million, or 2.3 per cent of AEY's total depreciable plant studied. During the 2003-2022 period examined, this account recorded \$0.065 million in retirements and \$0.014 million in net salvage costs. The full-depth net salvage statistic indicated an overall -21 per cent.

⁶⁶ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF pages 90-93 and 195.

⁶⁷ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF pages 71-72, 92-93 and 195.

146. Canadian electric generation and distribution peer utilities indicated net salvage ranging from zero to -13 per cent.⁶⁸
147. AEY recommended implementing a net salvage of -10 per cent based on AEY's recent experience and near-term requirements, and the results of the traditional net salvage study.

5.3.11.1 Board Findings

148. The Board is not prepared to implement a net salvage of -10 per cent as requested given the limited amount of data available in the net salvage study. The Board observes that implementing a -10 per cent would result in an annual accrual of net salvage expense of approximately \$0.017 million which is more than all the costs of removal incurred to date on this account. The Board does not find this to be a reasonable outcome.
149. However, given that it appears there is a trend of both asset retirements and costs of removal commencing in the years 2018-2022, the Board considers a net salvage of -1 per cent to be reasonable until more information is available. The annual accrual associated with a -1 per cent net salvage is approximately \$0.001 million⁶⁹ and is more in line with recent annual amounts of net salvage being incurred in this account at this time.⁷⁰
150. AEY is directed to implement a net salvage of -1 per cent for Account 341.20 – Generation Diesel – Internal Combustion Structures, in its compliance filing to this Board Order.

5.3.12 Views of AEY - Account 342.20 – Generation Diesel – Internal Combustion Fuel Holders, Producers and Accessories

151. Account 342.20 – Generation Diesel – Internal Combustion Fuel Holders, Producers and Accessories⁷¹ comprises approximately \$3.4 million, or 1.3 per cent of AEY's total depreciable plant studied. During the 1983-2022 period examined, this account recorded \$0.107 million in retirements and \$0.023 million in net salvage costs. The full-depth net salvage statistic indicated an overall -21 per cent.

⁶⁸ Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-003(c) Attachment 1, PDF page 46.

⁶⁹ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF page 224, calculated as \$0.166 million * 1 per cent.

⁷⁰ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF page 196.

⁷¹ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF pages 72-73, 92-93 and 197.

152. Canadian electric generation and distribution peer utilities indicated net salvage ranging from zero to -15 per cent.⁷²
153. AEY recommended implementing a net salvage of -15 per cent based on AEY's recent experience and near-term requirements, and the results of the traditional net salvage study.

5.3.12.1 Board Findings

154. The Board is not prepared to implement a net salvage of -15 per cent as requested given the limited amount of data available in the net salvage study. The Board observes that implementing a -15 per cent would result in an annual accrual of net salvage expense of approximately \$0.013 million⁷³ which is significantly more than the recent annual costs of removal being incurred for this account. The Board does not find this to be a reasonable outcome.
155. However, given that it appears there is a trend of both asset retirements and costs of removal commencing in the years 2018-2022, the Board considers a net salvage of -1 per cent to be reasonable until more information is available. The annual accrual associated with a -1 per cent net salvage is approximately \$0.001 million⁷⁴ and is more in line with recent annual amounts of net salvage being incurred in this account at this time.⁷⁵
156. AEY is directed to implement a net salvage of -1 per cent for Account 342.20 – Generation Diesel – Internal Combustion Fuel Holders, Producers and Accessories, in its compliance filing to this Board Order.

5.3.13 Views of AEY - Account 343.20 – Generation Diesel – Internal Combustion Generators

157. Account 343.20 – Generation Diesel – Internal Combustion Generators⁷⁶ comprises approximately \$20.5 million, or 7.7 per cent of AEY's total depreciable plant studied. During the 2013-2022 period examined, this account recorded \$4.5 million in retirements and \$0.476 million in net salvage costs. The full-depth net salvage statistic indicated an overall -10 per cent.

⁷² Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-003(c) Attachment 1, PDF page 46.

⁷³ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF page 92.

⁷⁴ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF page 226, calculated as \$0.088 million * 1 per cent

⁷⁵ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF page 197.

⁷⁶ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF pages 73-74, 92-93 and 198.

158. Canadian electric generation and distribution peer utilities indicated net salvage ranging from zero to -5 per cent.⁷⁷
159. AEY recommended implementing a net salvage of -10 per cent based on AEY's recent experience and near-term requirements, and the results of the traditional net salvage study.

5.3.13.1 Board Findings

160. The Board observes there is a reasonable amount of data available for this account upon which AEY has relied and based its proposed -10 per cent net salvage. However, the per cent requested is higher than that of AEY's peer utilities.
161. When asked for additional rationale explaining why AEY proposed a negative net salvage per cent greater than that of its peers, AEY's response⁷⁸ did not provide specific explanations that were helpful to the Board. For this reason, the Board finds it is reasonable to limit AEY's net salvage per cent for this account to that of its peers, being -5 per cent.
162. AEY is directed to implement a net salvage of -5 per cent for 343.20 - Generation Diesel – Internal Combustion Generators in its compliance filing to this Board Order.

5.3.14 Views of AEY - Account 345.20 - Generation Diesel – Internal Combustion Accessory

163. Account 345.20 - Generation Diesel – Internal Combustion Accessory⁷⁹ comprises approximately \$5.2 million, or 1.9 per cent of AEY's total depreciable plant studied. During the 2013-2022 period examined, this account recorded \$0.189 million in retirements and \$0.022 million in net salvage costs. The full-depth net salvage statistic indicated an overall -12 per cent.
164. Canadian electric generation and distribution peer utilities indicated net salvage ranging from zero to -17 per cent.⁸⁰
165. AEY recommended implementing a net salvage of -10 per cent based on AEY's recent experience and near-term requirements, and the results of the traditional net salvage study.

⁷⁷ Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-003(c) Attachment 1, PDF page 46.

⁷⁸ Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-009, PDF pages 265-266.

⁷⁹ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF pages 74-75, 92-93 and 199.

⁸⁰ Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-003(c) Attachment 1, PDF page 46.

5.3.14.1 Board Findings

166. Within the most recent four years of the data provided in the study, the Board observes there has only been one year in which retirements were recorded and no years in which net salvage costs were incurred. Given the limited and sporadic nature of the data available, and the absence of a clear trend of asset retirements or costs of removal, the Board finds there to be insufficient information to approve a net salvage per cent for this account at this time. AEY may submit further detail respecting this account for the Board to consider at the time of its next depreciation study.
167. AEY is directed to implement a net salvage of 0 per cent for Account 345.20 – Generation Diesel – Internal Combustion Accessory in its compliance filing to this Board Order.

5.3.15 Views of AEY - Account 346.20 - Generation Diesel – Internal Combustion Miscellaneous

168. Account 346.20 - Generation Diesel – Internal Combustion Miscellaneous⁸¹ comprises approximately \$0.081 million, or less than 1 per cent of AEY's total depreciable plant studied. During the 1992-2022 period examined, this account recorded \$0.042 million in retirements and \$0.020 million in net salvage costs. The full-depth net salvage statistic indicated an overall -47 per cent.
169. Canadian electric generation and distribution peer utilities indicated net salvage of zero per cent.⁸²
170. AEY recommended implementing a net salvage of -5 per cent.

5.3.15.1 Board Findings

171. The Board is not prepared to implement a net salvage of -5 per cent as requested given the limited amount of data available in the net salvage study and the lack of peer comparators. Furthermore, within the depreciation study there was no dedicated analysis provided for this account.
172. However, given it appears there is a trend of both asset retirements and costs of removal commencing between the years 2019-2022, the Board considers a net salvage of -2 per cent to be reasonable until more information is available.

⁸¹ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF pages 90-93 and 200.

⁸² Exhibit B-6, AEY-YUB-2-003(c) Attachment 1, PDF page 46.

173. AEY is directed to implement a net salvage of -2 per cent for Account 346.20 – Generation Diesel – Internal Combustion Miscellaneous in its compliance filing to this Board Order.

5.3.16 Views of AEY - Account 362.00 – Distribution – Station Equipment

174. Account 362.00 - Distribution – Station Equipment⁸³ comprises approximately \$5.2 million, or 2.8 per cent of AEY’s total depreciable plant studied. During the 1985-2022 period examined, this account recorded \$0.271 million in retirements and \$0.102 million in net salvage costs. The full-depth net salvage statistic indicated an overall -38 per cent.
175. AEY was unable to explain a lack of net salvage costs in relation to asset retirements during the years 1985-1991.⁸⁴
176. Canadian electric generation and distribution peer utilities indicated net salvage ranging from zero to -30 per cent.⁸⁵
177. AEY recommended implementing a net salvage of -10 per cent based on AEY’s recent experience and near-term requirements, and the results of the traditional net salvage study.

5.3.16.1 Board Findings

178. With respect to Account 362.00 – Distribution – Station Equipment (previously identified as 477.10 – Distribution – Substation Equipment),⁸⁶ and AEY’s previous depreciation study, a copy of which was provided in AEY-YUB-2-005(a),⁸⁷ the Board observes there is a disconnect between certain net salvage data provided in the 2011 Gannett Fleming Canada ULC (Gannett Fleming) depreciation study and the current 2022 Concentric depreciation study. This is despite AEY comments that the new study “layered on the data for the period of 2013 up until 2022 to Mr. Kennedy to perform the study.”⁸⁸
179. In the 2022 Concentric depreciation study, Account 362.00 – Transmission – Station equipment, within the asset retirements and cost of removal recorded for this account, there are no transactions shown for the years 1998-2017 whereas in the 2011 Gannett Fleming depreciation study, Account 477.10 – Distribution – Substation

⁸³ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF pages 75-76, 92-93 and 201.

⁸⁴ Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-013, PDF page 272.

⁸⁵ Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-003(c) Attachment 1, PDF page 46.

⁸⁶ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF page 64.

⁸⁷ Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-005(a), Attachment 1, PDF pages 52-259.

⁸⁸ Transcripts, Volume 4, PDF page 82.

Equipment, indicates cost of removal for each year 2000 through 2010 in the amount of \$0.146 million.⁸⁹

180. Given there appears to be an unexplained discrepancy in the data used by Concentric in its analysis, the Board will not approve the requested net salvage of -10 per cent for this account. AEY may submit further detail respecting this account for the Board to consider at the time of its next depreciation study,
181. AEY is directed to implement a net salvage of 0 per cent for Account 362.00 – Distribution – Station equipment, in its compliance filing to this Board Order.

5.3.17 Views of AEY - Account 362.10 – Distribution - System Communication and Control

182. Account 362.10 - Distribution – System Communication and Control⁹⁰ comprises approximately \$7.5 million, or 2.8 per cent of AEY's total depreciable plant studied. During the 2019-2022 period examined, this account recorded \$0.028 million in retirements and \$0.004 million in net salvage costs. The full-depth net salvage statistic indicated an overall -13 per cent.
183. Canadian electric generation and distribution peer utilities indicated net salvage ranging from zero to -30 per cent.⁹¹
184. AEY recommended implementing a net salvage of -10 per cent based on AEY's recent experience and near-term requirements, and the results of the traditional net salvage study.

5.3.17.1 Board Findings

185. The Board is not prepared to implement a net salvage of -10 per cent as requested given the limited amount of data available in the net salvage study. The Board observes that implementing a -10 per cent would result in an annual accrual of net salvage expense of approximately \$0.007 million⁹² which, as noted above, is more than all the costs of removal incurred to date on this account. The Board does not find this to be a reasonable outcome.
186. However, given that it appears there is a trend of both asset retirements and costs of removal commencing between the years 2019-2022, the Board considers a net salvage of -1 per cent to be reasonable until more information is available.

⁸⁹ Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-005(a), Attachment 1, PDF page 186.

⁹⁰ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF pages 90-93 and 202.

⁹¹ Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-003(c) Attachment 1, PDF page 46.

⁹² Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF page 92.

187. AEY is directed to implement a net salvage of -1 per cent for Account 362.10 – Distribution - System Communication and Control, in its compliance filing to this Board Order.

5.3.18 Views of AEY - Account 364.00 – Distribution - Poles, Towers and Fixtures

188. Account 364.00 – Distribution - Poles, Towers and Fixtures⁹³ comprises approximately \$53.3 million, or 20.1 per cent of AEY's total depreciable plant studied. During the 1983-2022 period examined, this account recorded \$2.287 million in retirements and \$2.260 million in net salvage costs. The full-depth net salvage statistic indicated an overall -103 per cent.
189. Canadian electric generation and distribution peer utilities indicated net salvage ranging from zero to -65 per cent.⁹⁴
190. AEY recommended implementing a net salvage of -50 per cent based on AEY's recent experience and near-term requirements, and the results of the traditional net salvage study.

5.3.18.1 Board Findings

191. The Board is not prepared to implement a net salvage of -50 per cent as requested in the net salvage study. The Board observes that implementing a -50 per cent would result in an annual accrual of net salvage expense of approximately \$0.598 million⁹⁵ which is significantly more than any annual costs of removal amounts recorded in this account since 1983. The Board does not find this to be a reasonable outcome.
192. At this time, the Board finds that a net salvage of -20 per cent would result in an annual net salvage accrual of approximately \$0.239 million.⁹⁶ This is more in line with the cost of removal amounts being incurred in this account within the last four years.⁹⁷
193. AEY is directed to implement a net salvage of -20 per cent for Account 364.00 – Distribution – Poles, Towers and Fixtures in its compliance filing to this Board Order.

⁹³ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF pages 76-77, 92-93 and 203.

⁹⁴ Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-003(c) Attachment 1, PDF page 46.

⁹⁵ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF page 92.

⁹⁶ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF page 241, calculated as \$1.195 million * 20 per cent.

⁹⁷ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF page 203.

5.3.19 Views of AEY - Account 365.00 – Distribution – Overhead Conductors and Devices

194. Account 365.00 – Distribution – Overhead Conductors and Devices⁹⁸ comprises approximately \$28.8 million, or 10.8 per cent of AEY's total depreciable plant studied. During the 1983-2022 period examined, this account recorded \$1.087 million in retirements and \$0.578 million in net salvage costs. The full-depth net salvage statistic indicated an overall -53 per cent.
195. Canadian electric generation and distribution peer utilities indicated net salvage ranging from zero to -40 per cent.⁹⁹
196. AEY recommended implementing a net salvage of -25 per cent based on AEY's recent experience and near-term requirements, and the results of the traditional net salvage study.

5.3.19.1 Board Findings

197. The Board is not prepared to implement a net salvage of -25 per cent as requested in the net salvage study. The Board observes that implementing a -25 per cent would result in an annual accrual of net salvage expense of approximately \$0.152 million which is significantly more than any annual costs of removal amounts recorded in this account since 1983. The Board does not find this to be a reasonable outcome.
198. The Board finds that a net salvage of -5 per cent would result in an annual net salvage accrual of approximately \$0.030 million,¹⁰⁰ which is more in line with the cost of removal amounts currently being incurred in this account at this time.
199. AEY is directed to implement a net salvage of -5 per cent for Account 365.00 – Distribution – Overhead Conductors and Devices in its compliance filing to this Board Order.

5.3.20 Views of AEY - Account 365.10 – Distribution – Overhead Services

200. Account 365.10 – Distribution – Overhead Services¹⁰¹ comprises approximately \$5.2 million, or 1.9 per cent of AEY's total depreciable plant studied. During the 1996-2022 period examined, this account recorded \$0.186 million in retirements and \$0.108 million in net salvage costs. The full-depth net salvage statistic indicated an overall -58 per cent.

⁹⁸ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF pages 77-78, 92-93 and 204.

⁹⁹ Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-003(c) Attachment 1, PDF page 46.

¹⁰⁰ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF page 241.

¹⁰¹ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF pages 78, 92-93 and 205.

201. Canadian electric generation and distribution peer utilities indicated net salvage ranging from zero to -8 per cent.¹⁰²
202. AEY recommended implementing a net salvage of -10 per cent based on AEY's recent experience and near-term requirements, and the results of the traditional net salvage study.

5.3.20.1 Board Findings

203. The Board observes the data available for this account, upon which AEY has based its proposed -10 per cent net salvage, is sporadic and limited. Further, the per cent requested is higher than that of AEY's peer utilities.
204. When asked for additional justification for their proposal for a negative net salvage per cent greater than that of its peers, AEY¹⁰³ did not provide specific explanations that were helpful to the Board. The Board therefore finds it reasonable to limit AEY's net salvage per cent for this account to the highest end of the range of its peers, being -8 per cent.
205. AEY is directed to implement a net salvage of -8 per cent for Account 365.10 – Distribution – Overhead Services in its compliance filing to this Board Order.

5.3.21 Views of AEY - Account 367.00 – Distribution – Underground Conductor and Devices

206. Account 367.00 – Distribution – Underground Conductor and Devices¹⁰⁴ comprises approximately \$34.2 million, or 12.9 per cent of AEY's total depreciable plant studied. During the 1985-2022 period examined, this account recorded \$0.351 million in retirements and \$0.508 million in net salvage costs. The full-depth net salvage statistic indicated an overall -145 per cent.
207. Canadian electric generation and distribution peer utilities indicated net salvage ranging from zero to -10 per cent.¹⁰⁵
208. AEY recommended implementing a net salvage of -25 per cent based on AEY's recent experience and near-term requirements, and the results of the traditional net salvage study.

¹⁰² Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-003(c) Attachment 1, PDF page 46.

¹⁰³ Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-015(c), PDF page 277.

¹⁰⁴ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF pages 78-79, 92-93 and 206.

¹⁰⁵ Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-003(c) Attachment 1, PDF page 46.

209. When asked for additional rationale to explain their proposal for a negative net salvage per cent greater than that of its peers, AEY's response¹⁰⁶ did not provide specific explanations that were helpful to the Board.

5.3.21.1 Board Findings

210. The Board is not prepared to implement a net salvage of -25 per cent as requested in the net salvage study. The Board observes that implementing a -25 per cent would result in an annual accrual of net salvage expense of approximately \$0.183 million¹⁰⁷ which, excluding one year, is not consistent with AEY's annual costs of removal being incurred in this account. The Board does not find this to be a reasonable outcome.
211. The Board finds that a net salvage of -10 per cent would result in an annual net salvage accrual of approximately \$0.073 million¹⁰⁸ which is more in line with the cost of removal amounts currently being incurred in this account at this time and is at the highest end of the range of net salvage per cents used by AEY's peer utilities.
212. AEY is directed to implement a net salvage of -10 per cent for Account 367.00 – Distribution – Underground Conductor and Devices in its compliance filing to this Board Order.

5.3.22 Views of AEY - Account 367.10 – Distribution – Underground Services

213. Account 367.10 – Distribution – Underground Services¹⁰⁹ comprises approximately \$6.3 million, or 2.4 per cent of AEY's total depreciable plant studied. During the 2010-2022 period examined, this account recorded \$0.118 million in retirements and \$0.029 million in net salvage costs. The full-depth net salvage statistic indicated an overall -24 per cent.
214. Canadian electric generation and distribution peer utilities indicated net salvage ranging from zero to -8 per cent.¹¹⁰
215. AEY recommended implementing a net salvage of -5 per cent based on AEY's recent experience and near-term requirements, and the results of the traditional net salvage study.

¹⁰⁶ Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-015(d), PDF page 277.

¹⁰⁷ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF page 92.

¹⁰⁸ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF page 249: Calculated as \$0.731 million * 10 per cent.

¹⁰⁹ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF pages 79-80, 92-93 and 207.

¹¹⁰ Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-003(c) Attachment 1, PDF page 46.

5.3.22.1 Board Findings

- 216. The Board finds that the results of the net salvage study support AEY's proposal to implement a net salvage of -5 per cent for this account and is approved.
- 217. AEY is directed to implement a net salvage of -5 per cent for Account 367.10 – Distribution – Underground Services in its compliance filing to this Board Order.

5.3.23 Views of AEY - Account 368.00 – Distribution – Line Transformers

- 218. Account 368.00 – Distribution – Line Transformers¹¹¹ comprises approximately \$41 million, or 15.4 per cent of AEY's total depreciable plant studied. During the 1995-2022 period examined, this account recorded \$1.227 million in retirements and \$0.971 million in net salvage costs. The full-depth net salvage statistic indicated an overall -79 per cent.
- 219. Canadian electric generation and distribution peer utilities indicated net salvage ranging from zero to -40 per cent.
- 220. AEY recommended implementing a net salvage of -10 per cent based on AEY's recent experience and near-term requirements, and the results of the traditional net salvage study.

5.3.23.1 Board Findings

- 221. The Board finds that the results of the net salvage study support AEY's proposal to implement a net salvage of -10 per cent for this account and is approved.
- 222. AEY is directed to implement a net salvage of -10 per cent for Account 368.00 – Distribution – Underground Services in its compliance filing to this Board Order.

5.3.24 Views of AEY - Account 370.00 – Distribution – Conventional Meters

- 223. Account 370.00 – Distribution – Conventional Meters¹¹² comprises approximately \$3 million, or 1.1 per cent of AEY's total depreciable plant studied. During the 2012-2022 period examined, this account recorded \$0.545 million in retirements and \$0.046 million in net salvage costs. The full-depth net salvage statistic indicated an overall -8 per cent.
- 224. Canadian electric generation and distribution peer utilities indicated net salvage of zero per cent.¹¹³

¹¹¹ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF pages 80-81, 92-93 and 208.

¹¹² Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF pages 81-82, 92-93 and 209.

¹¹³ Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-003(c) Attachment 1, PDF page 46.

225. AEY recommended implementing a net salvage of -5 per cent based on AEY's recent experience and near-term requirements, and the results of the traditional net salvage study.
226. When asked for additional rationale to explain its proposal for a negative net salvage per cent greater than that of its peers, AEY¹¹⁴ did not provide specific explanations that were helpful to the Board.

5.3.24.1 Board Findings

227. The Board is not prepared to implement a net salvage of -5 per cent as requested in the net salvage study. The Board observes that implementing a -5 per cent would result in an annual accrual of net salvage expense of approximately \$0.008 million¹¹⁵ which is not consistent with AEY's six most recent years of annual costs of removal incurred in this account. The Board does not find this to be a reasonable outcome.
228. At this time, the Board finds that a net salvage of -2 per cent would result in an annual net salvage accrual of approximately \$0.003 million.¹¹⁶ This is more in line with the average annual amount of net salvage being incurred in this account over the last 10 years,¹¹⁷ notwithstanding that -2 per cent is a per cent greater than that used by AEY's peer utilities.
229. AEY is directed to implement a net salvage of -2 per cent for Account 370.00 – Distribution – Conventional Meters in its compliance filing to this Board Order.

5.3.25 Views of AEY - Account 373.00 – Distribution – Street Lights

230. Account 373.00 – Distribution – Street Lights¹¹⁸ comprises approximately \$13.6 million, or 5.1 per cent of AEY's total depreciable plant studied. During the 1995-2022 period examined, this account recorded \$0.492 million in retirements and \$0.386 million of net salvage costs. This is comprised of costs of removal of \$0.399 million offset by the receipt of gross salvage of \$0.013 million. The full-depth net salvage statistic indicated an overall -79 per cent.
231. Canadian electric generation and distribution peer utilities indicated net salvage ranging from zero to -20 per cent.¹¹⁹

¹¹⁴ Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-017(b), PDF page 289.

¹¹⁵ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF page 92.

¹¹⁶ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF page 256, calculated as \$0.166 million * 2 per cent.

¹¹⁷ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF page 209.

¹¹⁸ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF pages 82, 92-93 and 211.

¹¹⁹ Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-003(c) Attachment 1, PDF page 46.

232. AEY recommended implementing a net salvage of -10 per cent based on AEY's recent experience and near-term requirements, and the results of the traditional net salvage study.

5.3.25.1 Board Findings

233. The Board finds that the results of the net salvage study support AEY's proposal to implement a net salvage of -10 per cent for this account and is approved.
234. AEY is directed to implement a net salvage of -10 per cent for Account 373.00 – Distribution – Street Lights in its compliance filing to this Board Order.

5.3.26 Views of AEY - Account 373.10 – Distribution - Sentinel Lights

235. Account 373.10 – Distribution – Sentinel Lights¹²⁰ comprises approximately \$0.285 million, or less than 1.0 per cent of AEY's total depreciable plant studied. During the 1983-2022 period examined, this account recorded \$0.038 million in retirements and \$0.020 million of net gross salvage. This is comprised of costs of removal of \$0.014 million offset by the receipt of gross salvage of \$0.034 million. The full-depth net salvage statistic indicated an overall +52 per cent.
236. Canadian electric generation and distribution peer utilities indicated net salvage ranging from zero to +20 per cent.¹²¹
237. AEY recommended implementing a net salvage of +10 per cent based on the results of the traditional net salvage study.

5.3.26.1 Board Findings

238. The Board finds that the results of the net salvage study support AEY's proposal to implement a net salvage of +10 per cent for this account and is approved.
239. AEY is directed to implement a net salvage of +10 per cent for Account 373.10 – Distribution – Sentinel Lights in its compliance filing to this Board Order.

5.3.27 Views of AEY - Account 390.00 – General Plant – Structures and Improvements

240. Account 390.00 – General Plant – Structures and Improvements¹²² comprises approximately \$5.2 million, or 2.0 per cent of AEY's total depreciable plant studied. During the 2015-2022 period examined, this account recorded \$0.136 million in

¹²⁰ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF pages 90-93 and 212.

¹²¹ Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-003(c) Attachment 1, PDF page 46.

¹²² Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF pages 90-93 and 213.

retirements and \$0.065 million of net salvage costs. The full-depth net salvage statistic indicated an overall -48 per cent.

- 241. Canadian electric generation and distribution peer utilities indicated net salvage ranging from zero to -5 per cent.¹²³
- 242. AEY recommended implementing a net salvage of -10 per cent based on the results of the traditional net salvage study.

5.3.27.1 Board Findings

- 243. The Board observes there to be a limited amount of data available for this account upon which AEY has relied and based its proposed -10 per cent net salvage. In addition, there were two years since 2015 which showed negative cost of removal amounts, and no transactions of any kind were reported for the year 2022.
- 244. The Board observes that the net salvage of -10 per cent requested is higher than that of AEY's peer utilities.
- 245. For these reasons, the Board finds it is reasonable to limit AEY's net salvage per cent for this account to that of the maximum for its peers, being -5 per cent.
- 246. AEY is directed to implement a net salvage of -5 per cent for Account 390.00 – General Plant – Structures and Improvements in its compliance filing to this Board Order.

5.3.28 Views of AEY - Account 390.01 – General Plant – Structures and Improvements Houses

- 247. Account 390.01 – General Plant – Structures and Improvements Houses¹²⁴ comprises approximately \$0.452 million, or less than 1.0 per cent of AEY's total depreciable plant studied. During the 2021-2022 period examined, this account recorded \$0.010 million in retirements and \$0.002 million of net salvage costs. The full-depth net salvage statistic indicated an overall -22 per cent.
- 248. Canadian electric generation and distribution peer utilities indicated net salvage ranging from zero to +85 per cent.¹²⁵
- 249. AEY recommended implementing a net salvage of -10 per cent based on the results of the traditional net salvage study.

¹²³ Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-003(c) Attachment 1, PDF page 46.

¹²⁴ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF pages 90-93 and 214.

¹²⁵ Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-003(c) Attachment 1, PDF page 46.

5.3.28.1 Board Findings

- 250. The Board observes that only one year of net salvage data was provided for this account and was the basis for AEY's proposed -10 per cent net salvage. Further, the per cent requested, in being a negative net salvage per cent, does not align with that of AEY's peer utilities, which indicate a +85 per cent net salvage.
- 251. For these reasons, the Board finds there to be insufficient justification to approve a net salvage per cent for this account at this time. AEY may submit further detail respecting this account for the Board to consider, at the time of its next depreciation study.
- 252. AEY is directed to implement a net salvage of 0 per cent for Account 390.01 – General Plant – Structures and Improvements Houses in its compliance filing to this Board Order.

5.3.29 Views of AEY - Account 392.20 – General Plant – Transportation Equipment, Fleet Vehicles Category 2

- 253. Account 392.20 – General Plant – Transportation Equipment, Fleet Vehicles Category 2¹²⁶ comprises approximately \$0.285 million, or 1.0 per cent of AEY's total depreciable plant studied. During the 2007-2022 period examined, this account recorded \$0.890 million in retirements and \$0.151 million of net gross salvage. This is comprised of costs of removal of \$0.019 million offset by the receipt of gross salvage of \$0.170 million. The full-depth net salvage statistic indicated an overall +17 per cent.
- 254. Canadian electric generation and distribution peer utilities indicated net salvage ranging from zero to +20 per cent.
- 255. AEY recommended implementing a net salvage of +10 per cent based on the results of the traditional net salvage study.

5.3.29.1 Board Findings

- 256. The Board finds that the results of the net salvage study support AEY's proposal to implement a net salvage of +10 per cent for this account and is approved.
- 257. AEY is directed to implement a net salvage of +10 per cent for Account 392.20 – General Plant – Transportation Equipment, Fleet Vehicles Category 2 in its compliance filing to this Board Order.

¹²⁶ Exhibit B-10.1, AEY Omissions & Updates – Blackline, PDF pages 90-93 and 215.

5.3.30 *Remaining accounts*

258. For all other accounts not identified in the preceding sub-sections, the Board observes that AEY proposed to use a net salvage of zero per cent. These accounts are included in Appendix 1.

5.4 Board directions on AEY's calculation of the amortization of reserve differences

259. In this sub-section, the Board discusses two matters pertaining to AEY's calculation of the amortization of reserve differences that are to be addressed by AEY in its compliance filing to this Board Order.
260. As a first matter, the Board notes that as AEY implements the net salvage per cents approved in the previous sub-sections, it is necessary for AEY to recalculate, among other things, its net salvage depreciation expense and associated amortization of reserve differences true up. These depreciation calculations will also be affected by any Board findings or directions related to forecast capital expenditures and capital additions and which may include necessary changes to AEY's forecast capital retirements and net salvage costs.
261. Accordingly, in its compliance filing, the Board directs AEY to recalculate its amortization of reserve differences calculation to include all relevant adjustments including those cited in the paragraphs above. Given that the amortization of reserve differences calculation is contained primarily in the output of a depreciation study, the Board expects AEY to provide information in its compliance filing, that is consistent with the information found in Attachment 1, Tables 1, 1A, 1B, 2, 2A, 2B and Section 8 (Detailed Depreciation Calculations) of the current Concentric Depreciation Study. All information identified here is to be provided and should support the updated amortization of reserve differences calculation and all other revisions required to AEY's depreciation expense calculation.
262. As a second matter, the Board has considered AEY's responses to AEY-YUB-2-001(n) and (o) which questioned various observed under and over recoveries of accumulated depreciation expense that had accumulated since the time AEY filed its last depreciation study.¹²⁷ In this IR, the Board asked if "AEY [would] agree to update its amortization of reserve differences amounts at the time of a future technical update as opposed to at the time of a full depreciation study."
263. AEY's response is as follows:

¹²⁷ Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-001(n) and (o), PDF pages 7-10; Exhibit B-10.1, AEY Omissions & Updates - Blackline, AEY-YUB-2-001(n), PDF page 3.

AEY is not opposed to updating its amortization of reserve differences amounts at the time of future technical updates. More frequent monitoring and true-up of accumulated depreciation variances, both life and net salvage, should ensure timely recovery/refund of accumulated depreciation variances, especially for accounts with short average remaining lives.¹²⁸

264. The Board agrees. The absence of an update to the amortization of reserve differences calculation simultaneous with the submission of a technical update creates intergenerational equity issues akin to those that AEY seeks to resolve through reinstating the pre-collection of net salvage costs. This is evident from the significant under and over recoveries for certain accounts, which were held to amortization of reserve differences calculation amounts without update since 1996.¹²⁹ For this reason, the Board directs AEY to update its amortization of reserve differences amounts at the time of any technical update to its 2022 and any future depreciation study.

5.5 Proposed treatment of contributions

5.5.1 Views of AEY

265. In its Application, AEY proposed updating its accounting practice related to contribution work in progress. Given AEY's expected installation of renewables and the related capital infrastructure, it expected that both construction and contribution work-in-progress balances would be significantly larger than previously experienced. Under AEY's current accounting practice, there is a mismatch between its treatment of contribution work in progress and the corresponding capital work in progress.
266. Historically, AEY included contribution work-in-progress in its computation of rate base. This resulted in a temporary reduction (due to the credit nature of a contribution) to AEY's rate base balance. AEY's proposal would remove contribution work-in-progress from its computation of rate base and result in a consistent treatment to that of AEY's construction work-in-progress balance, which is similarly excluded from rate base calculations. In effect, the contribution work-in-progress

¹²⁸ Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-001(o), PDF page 10.

¹²⁹ AEY response to Undertaking 20: AEY notes it addressed the large debit balance in accumulated depreciation net salvage for Account 390.01 houses (Account 488.20 at that time) in its 2008-2009 GRA in reply to YEC-YECL-II-4(b)(i); please refer to Attachment 1. "In summary: Since 1986 the net salvage rate applied to houses was -9.72% which was the rate applied to Alberta Power houses. Use of this rate resulted in a significant expense over time. Because there were no general rate applications since 1996 the rate remained in place." AEY's proposed Net Salvage parameters in its 2013-2015 GRA included a provision to true up this balance over the asset's remaining life, which was denied as part of the denial to reinstate the collection of Net Negative Salvage in Board Order 2014-06. There have been no material transactions in this account since 2004. AEY cannot readily comment on any material transactions prior to 2004 since records for this account are stored offsite.

balance and the corresponding capital work-in-progress balance would offset each other.

267. Treating the contribution and construction work-in-progress balances in lockstep, as essentially offsetting expenditures, would smooth out rate base and revenue requirement trends over the long term, and eliminate the accumulation of allowance for funds used during construction (AFUDC) on the related project.
268. AEY clarified that, due to the volume of customer contributed work forecast during the test period, AEY's proposal increases revenue requirement in 2023-2024 by approximately \$1.7 million, but would decrease the cumulative revenue requirement over the life of the contributed capital assets.
269. AEY provided an illustrative example showing that, under its proposed method, contributions work in progress is used to fund the capital work in progress and, accordingly, the relative capital does not accumulate AFUDC.¹³⁰
270. During the oral hearing, and in response to Board IRs, AEY confirmed that its proposal to update its practices with respect to contributions was consistent with the methodology approved by the Alberta Utilities Commission for AEY's sister company, in ATCO Electric Transmission, in Decision 2013-358,¹³¹ and confirmed in Decision 20272-272-D01-2016,¹³² and Decision 26573-D01-2023.¹³³

5.5.2 Board Findings

271. The Board accepts AEY's rationale for implementing a revised accounting treatment for its contribution work-in-progress, finding that, in the long-term, ratepayers will benefit from the avoidance of the accumulation of AFUDC on the related capital work in progress. AEY's proposal is approved.
272. The Board directs AEY to implement its revised accounting practice for contributions in its compliance filing to this Board Order.

¹³⁰ Exhibit B-4, Consolidated IR responses, AEY-YUB-001(h), Attachment 1, PDF page 1010 (Proposed method) and PDF page 1011 (Current method.)

¹³¹ AEY response to Undertaking 5: Alberta Utilities Commission, Decision 2013-358, ATCO Electric Ltd., 2013-2014 Transmission General Tariff Application, September 24, 2013, Paragraph 842, PDF page 188.

¹³² AEY response to Undertaking 5: Alberta Utilities Commission, Decision 20272-D01-2016, ATCO Electric Ltd., 2015-2017 Transmission General Tariff Application, August 22, 2016, Paragraph 88, PDF page 301.

¹³³ AEY response to Undertaking 5: Alberta Utilities Commission, Decision 26573-D01-2023, ATCO Electric Ltd., Disposal of 2018-2021 Transmission Deferral Accounts and Annual Filing for Adjustment Balances, April 26, 2023, Paragraph 72, PDF pages 19-20.

5.6 Board directions on AEY's amortization of Fish Lake Water Licence and Demand Side Management (DSM) program study costs

273. The Board continues to approve AEY's amortization of the Fish Lake Water Licence based on an implied life of 25 years (equating to a 4 per cent amortization rate) and the Demand Side Management program costs based on an implied life of 5 years (equating to a 20 per cent amortization rate.)
274. In the case of the DSM program costs, the Board also approves AEY's proposal to refund the over-collection of costs related to DSM in 2023 in the amount of \$0.563 million. Doing so, will complete AEY's collection of its capital investment in this program and no further amortization costs are forecast beyond 2023.¹³⁴
275. Information respecting the DSM over-collection and the use of a deferral account for costs of this nature is discussed in further detail within sub-section 9.1.7 – Demand side management (DSM) program deferral account.

6 Return on rate base

6.1 Views of AEY

6.1.1 Return on Rate Base

276. AEY included the following information on return on rate base:

Table 13: AEY Return on Rate Base (\$000)

	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals							Test Period	
Return on Rate Base	7,280	8,409	8,490	8,646	8,584	8,228	8,440	8,301	9,102

Source: Exhibit B-1, Application, Table 8:1, Return on Rate Base, PDF page 127.

276. AEY explained that the growth in return on rate base for the forecast period is a result of capital additions and an increase in the return on equity (ROE).
277. The components of the return on rate base as identified by AEY are for cost of capital: capital structure and cost of capital (return on equity); forecast long-term debt rates; and no-cost capital. For rate base the components are: capital additions;

¹³⁴ Exhibit B-6, AEY Round 2 IR responses, AEY-YUB-2-002, PDF page 32-34.

contributions; deferred charges and credits; and working capital. The components of cost of capital are discussed below.

6.1.1.1 Cost of capital

278. AEY has requested the Board use the British Columbia Utilities Board (BCUC) Generic Cost of Capital (GCOC) proceeding that was issued in September 2023 as the benchmark for determining ROE. In addition, AEY requested a 75 basis point risk premium over the BCUC benchmark utility.¹³⁵

6.1.1.2 Rate of return on capital

279. The British Columbia Utilities Commission (BCUC), through its Generic Cost of Capital (GCOC) proceeding and its decision and order G-236-23 (September 5, 2023) established a benchmark return of equity (ROE) of 9.65 per cent for Fortis Energy Inc (FEI, a gas utility) and FortisBC (Electric) (FBC) an electric utility.¹³⁶ In that decision, the BCUC did not identify which of the two utilities (FEI or FBC) will serve as the benchmark utility. AEY argued that the BCUC amount of 9.65 per cent should be the starting point for determining AEY's ROE.

6.1.1.3 Views of interveners

280. Mr. Maissan, agreed with the BCUC benchmark as an appropriate base.¹³⁷ The NDP argued that a fair return for AEY is 9.0 per cent and is a reasonable and expected return for Yukon utilities.¹³⁸ Mr. Yee did not provide any direct comments in his argument regarding ROE.¹³⁹ The UCG argued that the Board is not obligated to use the recent BCUC decision for ROE and has the discretion to utilize AUC decisions. The UCG also advanced that the BCUC changed the equity thickness giving their benchmark utility a higher grade of risk premium. The UCG submitted that a more appropriate and fair return is the 9.3 per cent awarded to Northland Utilities in the Northwest Territories.¹⁴⁰ YEC supported the use of the BCUC benchmark and the use of the BCUC approved ROE of 9.65 per cent as the starting point for ROE determinations.¹⁴¹

6.1.1.4 Board Findings

281. In AEY's (then YECL) 2008-2009 GRA, AEY argued:

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

¹³⁵ Exhibit B-1, Application, PDF page 130.

¹³⁶ Exhibit B-9, response to direction 4, Attachment 1, PDF page 153.

¹³⁷ Maissan Final Argument, PDF page 7.

¹³⁸ Yukon NDP Caucus Final Argument, PDF page 5.

¹³⁹ Yee Final Argument, PDF page 10.

¹⁴⁰ UCG Final Argument, PDF page 3.

¹⁴¹ YEC Final Argument, PDF pages 3-4.

costly matter, given the current state of ROE determination throughout Canadian regulatory jurisdictions.¹⁴²

282. In Appendix A to Board Order 2009-02, the Board stated:

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 issue.¹⁴³

283. In YEC's 2008-2009 GRA decision, the Board reinforced its determination regarding efficiency for ROE issues previously stated in Board Orders 2005-12 and 2009-02¹⁴⁴. In Appendix A to Board Order 2009-08, the Board said:

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.¹⁴⁵

284. The Board continued to approve the use of the BCUC benchmark in Decisions 2014-06, 2017-01, 2018-10 and 2022-03.¹⁴⁶

285. Based on the above, the Board accepts the result of the most recent BCUC GCOC proceeding as the benchmark or starting point for ROE determinations in the Yukon jurisdiction. The Board continues to be of the view that utilization of the BCUC benchmark provides the most efficient means of addressing an inherently complex and costly matter. The starting point for ROE determinations for this proceeding is 9.65 per cent.¹⁴⁷

¹⁴² YECL 2008-2009 GRA, YECL Argument, PDF page 24, argument page 23.

¹⁴³ Appendix A to Board Order 2009-02, PDF page 31.

¹⁴⁴ This approach was confirmed in Appendix A to Board Order 2013-01, PDF page 47.

¹⁴⁵ Appendix A to Board Order 2009-08, YEC 2008-2009 GRA, PDF pages 61-62, paragraphs 280-282.

¹⁴⁶ Decision 2014-06, YECL 2013-2015 GRA, PDF page 56. Decision 2017-01, YECL 2016-2017 GRA, PDF page 38, paragraph 182. Decision 2018-10, YEC 2017-2018 GRA, PDF pages 51-52, paragraph 246. Decision 2022-03, YEC 2021 GRA, PDF page 47, paragraph 224 describes YEC's use of the BCUC benchmark.

¹⁴⁷ Exhibit B-9, AEY Responses to Motions and YUB Directions, PDF page 153.

6.1.2 Views of AEY on Equity premium

286. AEY engaged Concentric Energy Advisors, Inc. (Concentric) to determine whether a risk premium relative to the BCUC GCOC benchmark utility would be appropriate and, if so, what the applicable risk premium should be. The report prepared by Concentric was submitted as Attachment 8.1 to the Application.¹⁴⁸
287. AEY submitted that it faces greater business risk than the average Canadian or British Columbia benchmark utility and therefore a risk premium is justified. Concentric submitted that the premium should be 75 basis points.¹⁴⁹
288. At the time of the application, Concentric, based on its research, recommended a risk premium of between 40 and 100 basis points in comparison to the BCUC benchmark utility (FEI).¹⁵⁰ The range was framed by FortisBC Electric at a 40 basis point premium and PNG-West (Pacific Northern Gas-West) at 46.5 basis points representing the upper boundary.¹⁵¹
289. The following table from the Concentric Report provides a summary and Concentric's view of authorized ROEs, equity ratios, and business risk relative to AEY.

Table 14: Concentric view of authorized ROEs and equity ratios

	ROE (%)	Equity Ratio (%)	Business risk relative to AEY
AEY (current)	9.00	40.0	N/A
Canadian	Electric	& Gas	Utilities
FEI	8.75	38.5	Lower
FBC	9.15	40.0	Lower
Ontario Electric Distributors	9.36	40.0	Lower
Newfoundland Power	8.50	45.0	Lower
Maritime Electric	9.35	40.0	Similar
AE Distribution	8.50	37.0	Lower
PNG-West	9.50	46.5	Higher

¹⁴⁸ Exhibit B-1, Application, Attachment 8.1, Concentric Report, PDF pages 136-171.

¹⁴⁹ Exhibit B-1, Application, Attachment 8.1, Concentric Report, PDF page 130.

¹⁵⁰ Exhibit B-1, Application, Attachment 8.1, Concentric Report, PDF pages 136-171.

¹⁵¹ Exhibit B-1, Application, Attachment 8.1, Concentric Report, PDF page 170: Concentric stated that AEY has higher business risks than other Canadian electric and gas distribution utilities with the Exception of PNG-West.

2022-2023 U.S.	U.S.	Electric	Utilities
Electric T&D Utilities	9.56	51.6	Lower

Source: Exhibit B-1, Application, Attachment 8.1, Concentric Report, PDF page 141.

290. In Concentric’s view, FEI has a lower business risk than AEY and is substantially larger than AEY. PNG-West has a higher business risk than AEY. FBC is larger than AEY and has more generation than AEY. Concentric added that AEY and Newfoundland Power have similar generation profiles and customer mixes, though Newfoundland Power is larger than AEY. Further, in comparison to Maritime Electric, Concentric submitted that AEY was smaller and had similar generation ownership risk but derives a smaller percentage of its supply from company owned electric generation than AEY. Relative to ATCO Electric Distribution (AED), Concentric added that AEY is smaller and has more volumetric risk associated with energy efficiency and conservation programs. Overall, based on the small size of AEY, Concentric stated “the extremely small size of AEY would support a risk premium of almost 400 basis points above the return for a large capitalization company.”^{152 153}
291. In argument AEY stated that “... Concentric's selected comparators are considered to have similar risk to AEY, and that a consideration of similar risk for comparators is consistent with the components of the Fair Return Standard.”¹⁵⁴ Further, AEY does not believe YEC is an appropriate comparator utility to AEY.¹⁵⁵ AEY submitted that, to AEY's knowledge, the Board has never considered AEY's or YEC's approved ROE as a benchmark for the other and adjusted it according to risk. AEY further submitted that:

... it is important to consider companies that are comparable to AEY with respect to their business and financial risk and how they would be assessed in the market, as discussed above and consistent with the Fair Return Standard. To do otherwise would, in AEY's respectful submission, introduce circularity into the Board's decision-making process in this regard.¹⁵⁶

6.1.2.1 Views of interveners

296. Mr. Maissan believed that the BCUC benchmark of 9.65 per cent was the appropriate base for AEY and accepted that AEY should receive an adder for risk factors. Mr. Maissan added that AEY’s risks have been played up, if not exaggerated, while, in practice, most of the risks identified by AEY are ones it has been working with for decades. Mr. Maissan opined that, in terms of sales or volume, AEY was less risky than Newfoundland Power or Maritime Electric. Mr. Maissan also noted that an IPP

¹⁵² Exhibit B-1, Application, Attachment 8.1, Concentric Report, PDF page 144.

¹⁵³ Exhibit B-1, Application, Attachment 8.1, Concentric Report, PDF pages 141-144.

¹⁵⁴ AEY Final Argument, PDF page 28, paragraph 74.

¹⁵⁵ Exhibit B-4, AEY Consolidated IR response, AEY-YUB-023, PDF pages 1102-1103.

¹⁵⁶ AEY Final Argument, PDF pages 29-30.

deferral account removes any risk to AEY in relation to that issue and that effect of microgeneration has been included in the sales forecast. Risk for sales volume to AEY are somewhat mitigated on a long-term basis as AEY normalizes its sales forecast to temperature. In Mr. Maissan's view, the risk of competition from alternative fuels is low. Mr. Maissan summarized his position by stating that "the AEY business and financial risks, subject to the Board's approvals noted above, is no different than it was at the time of the AEY 2016-2017 GRA."¹⁵⁷ An ROE of 9.65 per cent and a risk premium of 0.25 per cent was recommended by Mr. Maissan.¹⁵⁸

297. The NDP argued that the Board should consider a lower ROE based on the following factors: the reduced cost of and ease of access to debt to AEY via CU Inc., the fact that AEY has already been earning more than their proposed ROE of 10.4 per cent, and the AUC decision that matching the ROE awarded by other regulator is not sufficient to satisfy the return standard. The NDP submitted that capital market attraction through a higher ROE should not be a consideration for the Board and added that it is unreasonable to continually award an increased ROE when the utility seems impervious to the market risks and conditions that it asserts affect its business. The NDP also stated that, given the excellent financial returns of AEY since their last GRA, the approved ROE should remain at nine per cent for the test years 2023 and 2024. Further, the NDP said that matching the ROE and deemed equity ratios awarded by other regulators, on its own, does not satisfy the fair return standard, nor does it establish just and reasonable rates. The NDP highlighted in its final argument that AEY's consultant, Concentric, could not provide a clear answer as to why AEY should receive a higher risk premium than Maritime Electric.¹⁵⁹ The view of the NDP is the current fair return of nine per cent for AEY at 40 per cent equity remains a reasonable expected return for Yukon utilities. Based on the determination of relative risks in Board Order 2009-02 and YEC's application for a risk premium of 45 basis points, the NDP argued that AEY should not be granted a risk premium of more than 25 basis points. In addition, the NDP submitted that the Board should continue to view YEC as an appropriate comparator for AEY and award a risk premium based on that. The NDP asserted that the IPP and micro-generation issues existed prior to AEY's last GRA for 2016-2017 and therefore the YUB should not accept that the risks associated with the energy transition has increased since their last GRA.¹⁶⁰ The NDP concluded by stating:

... the remarkable ability of AEY to earn in excess of its allowed ROE despite the continued risks of the energy transition, 3 years of an economically disruptive global pandemic and increasingly erratic and unpredictable year-

¹⁵⁷ Maissan Final Argument, PDF page 10.

¹⁵⁸ Maissan Final Argument, PDF pages 7-10.

¹⁵⁹ NDP Final Argument, PDF page 6, paragraphs 37-40.

¹⁶⁰ NDP Final Argument, PDF pages 4-7.

round weather demonstrates that the actual risks to AEY's business are much lower than they have been made out to be. As a result, the Yukon NDP argues that the current risk premium of 0.25 percent is sufficient to cover the risks faced by AEY.¹⁶¹

298. The UCG argued that the Board is not obligated to use the recent BCUC decision for ROE. The UCG submitted that the recent ROE award to Northland Utilities of 9.30 per cent is a more appropriate return for AEY. The UCG added that AEY has approved or requested approval for several deferral accounts which reduce the risk faced by AEY. Further, in the UCG's view, the use of electricity purchase agreements (EPAs) protects AEY from risk related to IPPs.¹⁶² In reply argument, the UCG stated "[t]he Northwest Territories decision on equity return would be the most comparable results for size, transition, and weather normalization. Both are isolated grid utilities, unlike all the other comparators that are connected to the NA grid."¹⁶³
299. YEC asserted that the business risk premium for YEC should be higher than AEY and the appropriate reference for ROE purposes should be FBC instead of FEI. YEC submitted that AEY's ROE must be considered in light of past Board assessments of AEY's business risk relative to FBC and evidence presented by AEY at the hearing, including confirmation of BCUC's determination that FBC's business risk has not changed substantially since its previous decision on this matter and that there is no reasonable basis to distinguish investor-owned publicly traded utilities from government owned utilities for ROE purposes.¹⁶⁴
300. In reply argument, Mr. Yee was supportive of the ROE positions presented by the other interveners.¹⁶⁵

6.1.2.2 AEY reply to interveners

301. Regarding YEC comments, AEY affirmed its support for the evidence of Concentric on how an appropriate risk premium is assessed from a market perspective. AEY also noted that smaller investor-owned, publicly held gas or electric utilities are better peers of AEY than a government-owned utility due to the reasonable presumption held by Concentric that there is no government support for AEY in the event of financial distress.¹⁶⁶
302. AEY stated Mr. Maissan's comments on ROE are arbitrary, unsupported, and do not address AEY's primary point that it be granted a risk premium due to its small size

¹⁶¹ NDP Final Argument, PDF page 7, paragraph 48.

¹⁶² UCG Final Argument, PDF pages 3-5.

¹⁶³ UCG Reply Argument, PDF page 5, paragraph 35.

¹⁶⁴ YEC Final Argument, PDF pages 3-5.

¹⁶⁵ Yee Reply Argument, PDF pages 4-5.

¹⁶⁶ AEY Reply Argument, PDF pages 7-8

relative to the comparator utilities analyzed by Concentric. AEY noted that it has additional risk due to elevated capital expenditures driven by energy transition issues. AEY took the position that the Board's decision related to AEY's business risk can only properly be based on the evidence of Concentric and no other independent or credible evidence was filed by the interveners.¹⁶⁷

303. In response to the UCG, AEY argued that the risk premium for AEY should be even higher than the recommended 75 basis points for the return equivalent to those for FEI and FBC, since the equity ratio for AEY at 40 per cent is lower than that of FEI or FBC.¹⁶⁸
304. AEY disagreed with the positions of the NDP. Maritime Electric has similar risk to AEY, but not comparable risk. According to AEY, the NDP position on what AEY's ROE should be is unclear, as the NDP, in its argument, recommended more than one ROE for AEY. Additionally, AEY noted that the NDP's reference to a GCOC decision from the AUC is inconsistent with the Board's practice of the BCUC's GCOC process and benchmark utility. Therefore, AEY asked that any comparisons to Alberta utilities and the Alberta GCOC proceeding should be disregarded.

6.1.2.3 Board Findings

305. AEY relied upon the Concentric report to support its position for a risk premium over the BCUC benchmark utility. The premise behind the Concentric report is the lower the capitalization level of a company the higher the return expected by investors.
306. Concentric was asked to provide support for its position that the returns for small, regulated utilities are more unpredictable.¹⁶⁹ In response, Concentric provided a 1995 article published in *Public Utilities Fortnightly* by Michael Annin, an analyst for Ibbotson and Associates, the firm which publishes historical market return data. The Board is of the view that this article is general in nature, and no explanation or supporting documentation was provided on its applicability to Canadian utilities. Therefore, it is of little use in determining the issue of AEY's risk premium. In addition, Concentric did not provide any regulatory decision that supported Mr. Annin's position.¹⁷⁰ The BCUC defined risk "as the probability that future cash flows will not be realized or will be variable resulting in a failure to meet investor expectations."¹⁷¹ The Board finds that AEY's ROE for the years 2016 to 2022 do not support that its

¹⁶⁷ AEY Reply Argument, PDF pages 12-13.

¹⁶⁸ AEY Reply Argument, PDF page 17.

¹⁶⁹ Exhibit B-4, AEY Consolidated IR Responses, AEY-YUB-1-31(b), PDF page 1122.

¹⁷⁰ Exhibit B-4, AEY Consolidated IR Responses, AEY-YUB-31(b), PDF page 1123.

¹⁷¹ From the YEC 2017-2018 GRA, Exhibit B-5, YEC response to YUB IRs, YUB-YEC-1-52, Attachment 2, BCUC Decision G-75-13, decision page 36, 4, PDF page 1082.

earnings are unpredictable,¹⁷² nor does AEY's earnings trend indicate that future cash flows will not be realized or will be variable resulting in a failure to meet investor expectations.

307. Further, the Board finds that the Concentric report provided in this Application is very similar to the Concentric Report filed in AEY's 2016-2017 GRA application. This was noted in an IR to AEY.¹⁷³ The main difference between the two documents (Concentric Report 2016 versus Concentric Report 2023) is the approach on the magnitude of utility size in determining ROE in the 2023 Concentric Report. However, if one accepts the premise of the 2023 Concentric report that size is the determining factor, then three companies with the same level of capitalization would have the same return premium. If the three companies were a generator, a transmission company, and a distribution company, all with the same level of capitalization, then there would be no difference in the return premiums for each of the companies. However, this is not the case. As noted below, Concentric has previously characterized generation as higher risk than transmission and distribution as lower risk than transmission. Size as the determining factor does not conform with the generally accepted hierarchy of utility risk (generation risk > transmission risk > distribution risk). As noted in Board Order 2017-01¹⁷⁴, given that the BCUC looked at multiple factors in determining a risk premium, the Board does not accept the premise that size is the determining factor for a risk premium.
308. Concentric was asked if AEY's fuel price risk, small size risk, weather risk, and sales volume risk have materially changed since AEY's 2016-2017 GRA. Concentric's responses confirmed that AEY has lower generation risk¹⁷⁵ and that generation risk is more important than fuel price risk.¹⁷⁶ AEY has proposed to continue with its fuel and purchase power deferral accounts¹⁷⁷ and that risks related to fuel prices and purchase power have not materially changed.¹⁷⁸ AEY's risk of small size risk has not changed since its last GRA.¹⁷⁹ Concentric has not undertaken a quantitative analysis of weather risk but states that weather risk has not materially changed.¹⁸⁰ Further,

¹⁷² See for example, Exhibit B-4, AEY Consolidated IR Responses, Table 1 in response to AEY-UCG-1-42(d). PDF page 468.

¹⁷³ Exhibit B-4, AEY Consolidated IR Responses, AEY-YUB-1-39, PDF page 1141, preamble to question, wherein the Board commented "The writeup for Section B. Changes in business risk since the last GRA in the Application is surprisingly similar to that in Section B of the Concentric report in the application for AEY's 2016-17 GRA."

¹⁷⁴ Appendix A to Board Order 2017-01, PDF page 43

¹⁷⁵ Exhibit B-4, AEY Consolidated IR Responses, AEY-YUB-29, PDF page 1118. A company with 8 per cent self-supply has a lower risk than a company with 45 per cent self-supply.

¹⁷⁶ Exhibit B-4, AEY Consolidated IR Responses, AEY-YUB-35(a), PDF page 1132.

¹⁷⁷ Exhibit B-4, AEY Consolidated IR Responses, AEY-YUB-35(b), PDF pages 1132-1133.

¹⁷⁸ Exhibit B-4, AEY Consolidated IR Responses, AEY-YUB-35(d), PDF page 1134.

¹⁷⁹ Exhibit B-4, AEY Consolidated IR Responses, AEY-YUB-32, PDF page 1125.

¹⁸⁰ Exhibit B-4, AEY Consolidated IR Responses, AEY-YUB-35, PDF page 1135.

Concentric could not definitively show that AEY faced any additional risk from alternative fuels.¹⁸¹ Concentric's views with respect to climate change and climate change initiatives is that these issues are not unique to AEY and also pertain to BCUC benchmark utilities.¹⁸² Sales volumes were not considered a material factor for risk premium determinations.¹⁸³

309. Overall, the Board did not find the evidence provided by Concentric helpful in making its determinations on ROE matters. As noted above, the Board adopted the BCUC benchmark because it provides the most efficient means of addressing an inherently complex and costly matter. The Board considers that the Concentric Report is not in keeping with this objective. Although it focused on the risk premium requested above the BCUC benchmark, it added more complexity to this issue and did not result in an efficient and less costly process for this inherently complex issue. Further, large portions of the report discuss matters that Concentric itself states are immaterial to the overall risk assessment of AEY.¹⁸⁴ Additionally, in the AEY 2016-2017 GRA, the Board made its views known regarding the comparators AEY provided in the 2016 Concentric Report. In the 2023 Concentric report, AEY provided a similar list of comparators to those in the 2016 Concentric report. When asked in the hearing about what new evidence contained in the 2023 Concentric report vis-à-vis the AEY 2016-2017 GRA that would cause the Board to make a different determination, Concentric responded that "... in terms of new evidence, I'm not sure we have anything different than what we had in the previous report."¹⁸⁵ and, "[w]e obviously recognize the board's prior decision on this, but we're hoping that they're willing to reconsider."¹⁸⁶
310. When AEY was asked whether AEY and YEC should be benchmarks to each other since they both have ROEs benchmarked from the same BCUC benchmark utility, AEY responded that: "... [y]our question obviously raises a different issue that we didn't specifically consider because we didn't think about YEC as being a comparable utility for our analysis."¹⁸⁷ The Board notes that in YECL's 2008-2009 GRA proceeding, in testimony, YECL acknowledged that relative to YECL, YEC has more risk.¹⁸⁸ In YEC's 2017-2018 GRA, a proceeding in which AEY was a participant, AEY was one of the utilities YEC was compared to for risk premium determination purposes.¹⁸⁹ The Board finds that not using YEC as a comparator to AEY and not acknowledging prior

¹⁸¹ Exhibit B-4, AEY Consolidated IR Responses, AEY-YUB-37, PDF pages 1138-1139.

¹⁸² Exhibit B-4, AEY Consolidated IR Responses, AEY-YUB-39 (a), PDF page 1142.

¹⁸³ Transcript, Volume 4, PDF page 14, lines 4-19.

¹⁸⁴ See preceding paragraph.

¹⁸⁵ Transcript, Volume 4, PDF page 8, lines 6-8.

¹⁸⁶ Transcript, Volume 4, PDF page 8, lines 22-24.

¹⁸⁷ Transcript, Volume 4, PDF page 12, lines 10-14.

¹⁸⁸ YECL 2008-2009 GRA, Transcript, Volume 2, October 8, 2008. Page 206 lines 4-7 inclusive.

¹⁸⁹ Appendix A to Board Order 2018-10, Section 4.8.4.3 PDF page 57.

Board determinations regarding the comparability of AEY and YEC is a material defect in the AEY/Concentric analysis.

311. In AEY's 2016-2017 GRA, the Concentric witness broadly characterized electric utility risk as generation having the highest risk, transmission having the next highest risk, and the electric utility functions pertaining to distribution as the lowest risk.¹⁹⁰ No evidence has been presented in this proceeding that would change that relative risk hierarchy which Concentric itself has advocated for in the past.
312. In Appendix A to Board Order 2017-01, the Board determined that the utilities submitted by Concentric were not comparable to AEY for ROE determinations for the following reasons: Maritime Electric's ROE was determined through a negotiated settlement; PNG-West's risk premium was due to customer growth, market demand, and throughput risks — conditions considered not applicable for AEY; and FBC had generation risk at a quantum level higher than AEY.¹⁹¹ For ROE purposes, AEY was asked what has changed to make the comparators proffered by Concentric applicable now versus when the Board issued its decision through Board Order 2017-01. Concentric responded "Again, I'm not sure that anything has changed, really."¹⁹²
313. Regarding the BCUC decision on the ROE for FBC, Concentric agreed that the BCUC determined that FBC's risk profile has not substantially changed since the previous BCUC GCOC decision. Although Concentric added that the equity ratio increased from 40 per cent to 41 per cent due to business risk, Concentric stated that it could not substantiate that claim from the decision.¹⁹³
314. Concentric provided evidence on size premiums for what it considered to be comparable utilities to AEY.¹⁹⁴ JPT-3 provided the size premium for the comparable utilities based on the implied market cap for each of those utilities. When Concentric was asked to provide the regulatory decision or reference to a regulatory decision, and the year of the pertinent regulatory decision that the size premium was accepted by the regulator for the utilities listed in JPT-3, the response was "[s]o what is shown in column I is really based on the numbers that are in the table below that. These aren't regulatory approved risk premiums. This is what the size premium would be for each one of these companies using the Kroll¹⁹⁵ data."¹⁹⁶ In addition, although the Kroll data suggests a risk premium to AEY of 480 basis points due to size, Concentric

¹⁹⁰ AEY 2016-2017 GRA, transcript volume 1 PDF page 93 line 2 to PDF page 94 line 7.

¹⁹¹ Appendix A to Board Order 2017-01, PDF pages 44-45, paragraphs 212-215.

¹⁹² Transcript, Volume 4, PDF page 19, lines 5-6.

¹⁹³ Transcript, Volume 4, PDF page 34, lines 2-8.

¹⁹⁴ Exhibits B-11.1 and B-11.2. The exhibits (Excel spreadsheets) were also referred to as JPT-2 and JPT-3.

¹⁹⁵ Formerly Duff and Phelps.

¹⁹⁶ Transcript, Volume 4, PDF page 43, lines 12-16.

concluded that a risk premium of between 40 and 100 basis points is appropriate for AEY and determined a risk premium of 75 basis points as reasonable, if not conservative.¹⁹⁷ Concentric has discounted the size premium from the Krall data by over 85 per cent. In the Boards view, the conclusions from the Kroll data regarding a size premium lacks credibility. The Concentric submission of the Kroll information was not of assistance to the Board as the risk premiums presented were hypothetical and not set by a regulator. For all these reasons, the Board places little or no weight on the 2023 Concentric report and AEY's submission in relation to this report.

315. In summary, the Board has previously ruled on several of the issues regarding equity premium brought forward by AEY/Concentric and Concentric has stated that the facts, as they pertain to AEY, surrounding those prior determinations have not changed. Based on the evidence in this proceeding, the Board finds that the returns for AEY are not unpredictable. Further, no regulatory decision supporting the position that returns for small utilities are unpredictable has been provided. The factors making up AEY's risk profile have not materially changed or have not materially changed from FBC in the latest BCUC Stage 2 GCOC decision. AEY/Concentric did not consider the Board's determination regarding comparable utilities as set out in Decision 2017-01 and could not confirm anything has changed since the Board's previous determinations on this issue. AEY/Concentric has not persuaded the Board that a largely distribution utility should be awarded a higher ROE than a utility with sizable generation or transmission assets - a deviation from the relative risk hierarchy of the main electric utility functions (generation/transmission/distribution). Further, as noted above, AEY/Concentric did not provide any regulatory decisions that support the size premiums as determined through the Kroll data (Exhibit B-11.2, JPT-3).
316. The Board has determined that AEY's risk factors have not materially changed since the Board's last determination on this issue. The Board took note that BCUC Decision G-236-23 provided ROEs for FEI and FBC but did not name a benchmark utility. In the Board's view, as FBC is an electric utility, it is more comparable to AEY than FEI (a gas distributor). The Board further took note that the BCUC determined that the risk profile for FBC has not materially changed.¹⁹⁸ The stage 2 proceeding for the latest BCUC GCOC has not concluded¹⁹⁹ in terms of relative risk to the BCUC benchmark utility.
317. As stated above, the Board has found the Concentric evidence not useful in determining an equity adjustment for AEY for its overall ROE. The Board continues to

¹⁹⁷ Exhibit B-1, Application, Attachment 8.1, Concentric Report, PDF page 171.

¹⁹⁸ Exhibit B-9, Direction 4, BCUC Decision and Order G-236-23, PDF page 80.

¹⁹⁹ The Stage 2 proceeding sets the benchmark utility and the relative risks (equity adjustment) of other utilities relative to the benchmark utility.

be of the view that FBC should be considered to have a higher risk than AEY for ROE purposes, as noted in Appendix A to Board Order 2017-01.

318. In that decision, the Board noted that FBC received a risk premium of 40 basis points to the BCUC benchmark utility (FEI) and then, based on the Board's previous finding on the difference between AEY's and FBC's risk, determined that AEY merited only a 25 basis point risk premium over the BCUC benchmark utility. That lower risk relative to FBC was quantified to be 15 basis points (calculated as 40-25).
319. In the current BCUC GCOC stage 1, the BCUC determined that FBC's risk profile has not materially changed since the last GCOC proceeding. In this proceeding, Concentric has stated that AEY's risk profile has not materially changed since the ROE determinations in Board Order 2017-01. Given the Board was not persuaded by the Concentric evidence in this proceeding and the risk profiles for FBC and AEY have not materially changed, the Board considers that AEY should earn a net lower ROE than FBC. As noted above, in 2017, the Board found that, comparatively, the risk premium for AEY under FBC was 15 basis points. Since the relative risk profiles of FBC and AEY have not materially changed since the last determination on this issue, the Board finds that AEY continues to be less risky than FBC by 15 basis points. FBC was awarded an ROE of 9.65 per cent. Therefore, the Board directs AEY to use an ROE of 9.50 (calculated as 9.65-0.15) per cent and reflect this change in its compliance filing to this Board Order.

6.1.3 Views of AEY on Common equity ratio

318. In its application, AEY sought to continue with the common equity ratio of 40 per cent for each of the test years 2023 and 2024. The common equity ratio requested by AEY continues the common equity ratio approved for AEY in Decision 2017-01 (AEY 2016-2017 GRA) and Decision 2014-06 (YECL 2013-2015 GRA).

6.1.3.1 Views of interveners

319. Mr. Maissan had no issue with AEY's proposed capital structure.²⁰⁰ The UCG stated "If the Board choses to use this BCUC decision with a return of 9.65%, it must recognize that the BCUC also changed the equity thickness to 45%, giving their benchmark Utility a higher grade of risk premium than AEY."²⁰¹ YEC submitted that the deemed equity for AEY remain at 40 per cent.²⁰² No other party directly commented on the common equity ratio proposed by AEY.

²⁰⁰ Maissan Final Argument, PDF page 6.

²⁰¹ UCG Final Argument, PDF page 3.

²⁰² YEC Final Argument, PDF page 3.

6.1.3.2 Board findings

320. Based on the position of the parties and no contradicting evidence being provided, the Board approves AEY's request for a common equity ratio of 40 per cent.

6.2 Cost of debt

6.2.1 Views of AEY

322. The cost of long-term debt rates was presented in the Application.²⁰³ AEY used an average long Canada Bond Rate and applied a spread to determine the forecast debenture rate. AEY provided its forecast as follows:

Table 15: Economic Indicators (%)

	2023	2024
Long Canada Bond Rate	2.50 - 3.00	2.55 – 3.05
Credit Spread	1.55	1.55
Debenture Rate	4.70	4.55
Recommended Rate	4.56	4.56
Issue Costs	0.05	0.05
Recommended All-in Rate	4.61	4.61

Source: Exhibit B-1, Application, Table 8.2: Economic Indicators, PDF page 131.

6.2.2 Views of interveners

323. Mr. Maissan had no issue with AEY's applied for cost of debt.²⁰⁴ The UCG stated that "the debt rates are somewhat reasonable, and we rely on the Board to find a balanced result".²⁰⁵

6.2.3 Board Findings

323. The Board has reviewed AEY's proposed long-term debt costs for new issues of debt during the test period. The Board finds the recommended all-in rate for AEY's cost of debt to be reasonable as no issues have been identified regarding the reasonableness of those long-term debt rates.

²⁰³ Exhibit B-1, Application, PDF pages 130-131.

²⁰⁴ Maissan Final Argument, PDF page 6.

²⁰⁵ UCG Final Argument, PDF page 7.

6.2.4 No cost capital

324. The Board's views with respect to AEY's no cost capital accounts and balances can be found in Section 9 of this Board Order.

7 Capital

7.1 Overview

325. In its Application, AEY provided information respecting its actual, approved and forecast capital expenditures and additions for the years 2016-2024 as shown in the following table:

Table 16: Summary of actual (A), approved (Appr) and forecast (F) capital expenditures and additions for the years 2016-2024 (\$ millions)

	2016A	2017A	2018A	2019A	2020A	2021A	2022A	2023F	2024F	2016 Appr	2017 Appr
Capital expenditures:											
Generation											
Generation	6.944	0.963	2.147	2.635	3.597	3.050	1.178	3.723	3.352	6.602	2.529
Renewables		0.208	0.080	1.007	1.087	1.330	3.749	6.044	2.436	-	-
Sub-total generation	6,944	1,171	2.227	3.642	4.684	4.380	4.926	9.767	5.788	6.602	2.529
Distribution											
New extensions	2.527	3.099	3.990	5.176	3.636	4.247	4.714	5.885	5.216	2.155	3.715
New extensions – IPP	-	-	-	-	-	0.366	1.394	1.115	-	-	-
Distribution improvements	4.103	3.819	2.318	2.634	1.658	3.180	2.028	5.195	9.081	4.335	4.153
Street and sentinel lighting	0.407	0.936	0.553	0.785	1.627	1.055	1.009	2.563	1.042	0.584	0.777
Meters	0.105	0.088	0.032	0.067	0.127	0.075	0.098	0.235	0.410	0.199	0.203
Transformers & regulators	0.324	0.213	0.070	0.262	0.385	0.222	(0.008)	0.928	0.275	0.367	0.091
Sub-total distribution	7.466	8.156	6.962	8.924	7.434	9.145	9.234	15.920	16.023	7.640	8.939
General, plant & equipment (GP&E)											
Computer	-	-	0.022	0.247	(0.004)	-	-	-	-	-	-
Land & buildings	0.089	0.105	0.091	0.072	0.147	(0.022)	0.095	0.232	0.794	0.065	0.239
Communication equipment	0.063	0.138	0.032	0.020	0.029	0.053	0.131	0.047	0.141	0.117	0.115

Tools, instruments & equipment	0.151	0.162	0.073	0.197	0.108	0.160	0.087	0.310	0.128	0.149	0.165
Office computer equipment	0.034	0.079	0.079	0.044	0.032	0.755	3.790	4.261	1.434	0.020	0.066
Transportation equipment	0.018	0.665	0.006	0.382	0.570	0.675	0.661	0.697	0.766	0.369	0.315
Other	-	-	-	-	-	-	-	-	-	0.037	0.102
Sub-total GP&E	0.374	1.150	0.303	0.962	0.883	1.621	4.753	5.547	3.263	0.757	1.002
Total capital expenditures	14.784	10.476*	9.491	13.529	13.001	15.147	18.914	31.234	25.073	14.999	12.471
Total capital additions	12.079	8.393	11.159	9.982	11.893	11.014	15.857	34.734	31.780	14.185	12.060
Contributions	(1.241)	(2.204)	(3.212)	(5.896)	(4.220)	(5.250)	(2.529)	(10.119)	(16.431)	(1.800)	(3.151)
Net capital additions	10.838	6.189	7.947	4.013	7.673	5.764	13.328	24.615	15.349	12.385	8.909

Source: Exhibit B-10.3 – AEY GRA Regulatory Schedules, S9.2, S9.1 and S8.12. *Note that the 2017 \$10.476 million capital expenditure is different than the amount provided by AEY in its Exhibit B-1, application in Table 9.1 – Capital Expenditures and Additions, PDF page 173 which indicates a 2017 \$10.527 million capital expenditure.

326. In support of its expenditures and additions, AEY provided business cases for:

- 2016-2017, where variances from actual to approved were both greater than 100 per cent and greater than \$100,000;²⁰⁶
- 2018-2022, where capital expenditures exceeded \$100,000;²⁰⁷
- 2023-2024, for projects with capital expenditures forecast to be \$500,000 or greater;²⁰⁸ and,
- significant upcoming projects, where capital expenditures are forecast to occur in 2023-2024 and beyond,²⁰⁹ and thus will not be capitalized until after the 2023-2024 Test Period.

²⁰⁶ Exhibit B1-6, Business Cases 01-03.

²⁰⁷ Exhibit B1-7, Business Cases 04-21.

²⁰⁸ Exhibit B1-8, Business Cases 22-38.

²⁰⁹ Exhibit B1-9, Business Cases 39-41.

327. In response to certain IRs, AEY provided additional information in support of both its actual and forecast capital expenditures and additions.²¹⁰
328. AEY stated that since the time of its 2016-2017 GRA, there has been significant load growth in Yukon due to the territory's rapidly growing population. The rising demand for electric service has led to the need for AEY's capital program to be strengthened and grown in order to keep pace with the increased demand, and its requirement to maintain safe and reliable service. AEY explained that while its net capital additions will peak in 2023 as a result of the Mayo substation and the CIS project going into service, it anticipated that 2024 capital requirements would not change substantially given the expected continued growth in Yukon.²¹¹

7.2 Views of AEY - opening rate base

329. AEY's opening 2023 rate base includes those capital additions related to projects applied for in AEY's 2016-2017 GRA. The 2023 opening rate base amount also includes capital additions and expenditures for the years 2018-2022, which were years in which no GRA was submitted.
330. In general, AEY stated there was a large "uptick" in 2022 net capital additions due, in part, to its ability to complete more projects coming out of the COVID-19 pandemic. There were also several multi-year projects that were completed and capitalized in 2022.
331. In response to IRs, AEY provided variance explanations supporting differences between 2016-2017 actual and approved capital costs. For non-test year capital costs, AEY provided explanations for the rationale and need for the capital project and the actual project costs incurred between 2018-2022.
332. With respect to Fish Lake Front End Roof Design project, during the oral hearing, AEY clarified that this project as detailed in Business Case 32 was behind schedule due to procurement issues and would be deferred until 2024. AEY stated:

We also had a couple of generation projects that will also be deferred to 2024, Fish Lake roof replacement and our Fish Lake 2 front end design as well.

...

²¹⁰ For example: Exhibit B-4, Consolidated IR responses, AEY-YUB-041(a)(viii) Attachment 1, PDF pages 1157-1159, (Replace Unit 643 – Bucket Truck), AEY-YUB-046(b) Attachment 1, PDF pages 1182-1187 (Old Crow Generation Capital Expenditure Information), AEY-YUB-046(b) Attachment 2, PDF pages 1195-1198 (Fish Lake Generation Capital Expenditure Information); Exhibit B-4.1: AEY-YUB-065(a) Attachment 1, PDF pages 2-10 (Advanced Meter Infrastructure) and AEY-YUB-066(b) Attachment 1, PDF pages 14-18 (Salesforce Business Analysis).

²¹¹ Exhibit B-1, Application, PDF page 173-174.

Our Fish Lake projects, those were delayed due to procurement. Most of our procurement is done through affiliates and ATCO Electric Alberta. They were very busy with wildfires at the beginning of the year, so the procurement for these didn't -- didn't take place until later in the year.

...

So the roof replacement is business case 39, and the front end design for Fish Lake 2 is also 30 -- sorry, roof replacement is number 32 and the front end design is business case 39.²¹²

333. AEY also pointed out that its Mayo Road and Whistle Bend – Leota substation projects, as detailed in Business Case 25, is behind schedule with construction and is delayed until at least 2024.

Sorry, the Mayo Road substation was delayed. It's not under construction. It's the next substation to be built. And Whistle Bend too is not under construction currently.

...

Just in -- I'd refer you to schedule 9.2 -- well, you don't have to go there, but just line 274 notes ...the costs for the Mayo Road substation, very similar. Total cost will be 2.8 million. Started last year. It was to be in service here in 2023, but we've had delays in the land permitting. So the substation is designed, the material -- the majority of the material we have on hand and ready to construct, but it just -- that project has been held up in land permitting. And then down to line 283 is the other substation for Whistle Bend that is referenced for business case 25, and it's a similar \$2.8 million cost. So the vast majority of the costs are material. So we would expect -- well, depending on -- the big transformers is the big cost. The equipment costs are the costs that can deviate or vary more than -- more than our labour costs or land costs. But just looking at those two, it's in the neighbourhood of \$2.8 million.”²¹³

7.2.1 Views of interveners

334. The UCG questioned how AEY was able to add capital costs to rate base during non-test years arguing that it did not agree with this concept given that it appeared tantamount to retroactive ratemaking. The UCG clarified that, while it does not object to AEY constructing utility assets for the purpose of providing safe and adequate utility service, until the review of any such assets constructed during a non-test-year period is brought before the Board, no rate base changes should be allowed.²¹⁴

²¹² Transcript, Volume 3, PDF pages 89-90.

²¹³ Transcript, Volume 3, PDF pages 83-84.

²¹⁴ UCG Final Argument, PDF page 9 and UCG Reply Argument, PDF page 6.

7.2.2 Views of AEY

335. In response to IRs,²¹⁵ and again during the oral hearing,²¹⁶ AEY explained to the UCG that the inclusion of non-test years' capital expenditures and additions does not constitute retroactive nor retrospective ratemaking. This is because any capital costs incurred outside of a test period are funded by the utility and are not incorporated into the rates that were established at the time of the last approved test year – in this case, the year 2017.²¹⁷

7.2.3 Board Findings

336. The Board agrees with AEY that the inclusion of its non-test year's capital expenditures and additions into 2023 opening rate base does not constitute retroactive or retrospective ratemaking. As explained by AEY, notwithstanding there may have been capital assets constructed and added to rate base during 2018-2022 (which were non-test years), AEY did not earn a return or collect depreciation expense on this utility funded investment during that time. It is only at the time of the next GRA, in this instance the years 2023-2024, that the 2018-2022 capital additions are reflected as part of AEY's 2023 opening rate base. If the Board finds in this decision that the capital additions are prudent, then AEY is approved to commence earning a return and collecting depreciation expense on its 2018-2022 capital investment through rates established prospectively for the years 2023-2024.
337. Accordingly, the Board finds that the UCG claim of retroactive ratemaking is incorrect and has been given no weight.
338. Having examined AEY's application, business cases, and IR responses, the Board is satisfied that AEY's 2023 opening rate base reflects prudently incurred capital additions for the years 2016-2022. AEY's 2023 opening rate base is approved, subject to the Board's findings and directions with respect to costs related to Business Case 32 – Fish Lake Roof Replacement and Business Case 25 - New Substations - Mayo Road. The Board's directions in this regard are detailed in the next three paragraphs.
339. The Board has observed that AEY intends to capitalize certain portions of Business Case 32 and Business Case 25 into its 2023 opening rate base, ahead of the completion of the entirety of the forecast project work. These are costs in the amount of \$0.043 million in 2021 and \$0.016 million in 2022 for Fish Lake Unit 1 Roof Design²¹⁸ and in the amount of \$0.400 million in 2022 for the procurement of the Mayo Road substation transformer procurement in the year 2022, respectively.

²¹⁵ Exhibit B-4, AEY Consolidated IR Responses, AEY-UCG-057, PDF page 658.

²¹⁶ Transcript, Volume 1, PDF pages 106-109 and Transcript, Volume 2, PDF page 26.

²¹⁷ AEY Final Argument, PDF pages 40-41.

²¹⁸ Exhibit B-10.3, AEY GRA Regulatory Schedules, Omissions & Updates, Blackline, S9.2, Line No. 13.

340. With respect to the two instances detailed above, the Board does not accept that portions of projects contained within a single business case that have been either completed or procured in isolation or in advance of the entire project at issue result in used and useful utility assets. Therefore, these expenditures for the Fish Lake Unit 1 Roof Design and the Mayo Road Substation transformer procurement cannot be capitalized into AEY's 2023 opening rate base in advance of the of completion of the balance of the two projects at issue.
341. Accordingly, to the extent that these expenditures have been capitalized into AEY's 2023 opening rate base, the Board directs that these costs be removed and remain in CWIP until the entirety of the capital project is in utility service. This direction is based on the AEY testimony provided during the oral hearing (as quoted above), that the Fish Lake Unit 1 Roof Replacement in Business Case 32 is behind schedule and that the costs are now forecast to be capitalized into rate base in 2024. In the case of Business Case 25, as noted above, Mayo Road Substation project is also currently behind schedule with construction delayed until at least 2024.

7.3 Views of AEY on its ability to complete its forecast capital expenditures and additions

342. A common theme raised by parties was the concern as to whether AEY would be able to complete all the capital work it had forecast for the years 2023-2024. During the oral hearing, AEY provided information that detailed the actual capital (expenditure) work it had completed as of October 31, 2023, in comparison to what it had forecast would be completed at the end of the year, and the amount that AEY had applied for in its application.

Table 17: AEY's capital expenditures: actual to October 31, 2023, full-year forecast and applied-for (\$ millions)

	Actual expenditures October 31, 2023	Full year forecast	Actual over(under) full year forecast	Applied-for 2023	Actual over(under) applied-for	Full year forecast over(under) applied-for
	(1)	(2)	(3) = (1)-(2)	(4)	(5) = (1)-(4)	(6) = (2) – (4)
Capital expenditures	20.8	24.9	(4.1)	31.2	(10.4)	(6.3)
Contributions in aid of construction	(11.1)	(13.1)	2.0	(16.5)	5.4	3.4
Net capital expenditures	9.7	11.8	(2.1)	14.7	(5.0)	(2.9)

Source: AEY Response to Undertaking 15: Capital YTD Costs – October 31, 2023, PDF page 647-648.

343. AEY explained that the full-year forecast amount (column 2 in the table above) is lower than the amount applied for (column 3 in the table above) “mainly due to delays in the Mayo Road substation project because of delays in receiving the required land use permit. The project is expected to be completed in 2024.”²¹⁹

7.3.1 Views of the interveners

344. In argument, Mr. Maissan stated that both he and the Board had questioned, through IRs, AEY’s “capability of delivering the very high capital budgets in 2023 and 2024.”²²⁰ In AEY’s September 28, 2023 responses, it stated it could achieve these goals. However, it was clearly not the case at the time of the December 4 to 7, 2023 oral hearing that AEY would be able to meet its applied-for 2023 capital forecast.
345. Mr. Maissan showed that, historically, it is common for AEY to underspend their approved capital expenditure forecast (and that often includes where what is approved by the Board is lower than what was applied for by AEY).²²¹ He recommended that the Board approve, for 2023, a total capital expenditure of not more than \$24.9 million which results in a net capital expenditure of not more than \$11.8 million. For 2024, Mr. Maissan recommended a minimum similar 20 per cent reduction from the applied-for capital expenditure of \$25.073 million (resulting in \$20.1 million total capital expenditure). Doing so would result in a net capital expenditure of \$14.934 million (as compared to the applied-for net capital expenditure of \$18.668 million).²²²
346. Although the Yukon NDP Caucus made no recommendation with respect to AEY’s applied-for capital forecasts, it similarly questioned AEY’s track record with respect to its capital forecasting methodology and the actual results achieved.²²³

7.3.2 Board Findings

347. While the Board appreciates and understands the concerns raised by interveners, it is not prepared to order a formulaic-based cut to AEY’s 2023-2024 capital expenditure forecast as recommended by Mr. Maissan. Instead, the Board will make its findings, specific to any capital projects at issue, by examining the actual evidence respecting AEY’s capital expenditure forecasts and AEY’s ability to meet its forecast capital spending. The Board’s analysis in this regard is found in the sub-sections which follow.

²¹⁹ AEY Response to Undertaking 15: Capital YTD Costs – October 31, 2023, PDF page 647-648.

²²⁰ Maissan Final Argument, PDF pages 12-13, referring to Exhibit B-4, AEY Consolidated IR Responses, AEY-YUB-042(b), PDF page 1163-1165, and AEY-JM-027(a), PDF pages 67-68.

²²¹ Maissan Final Argument, PDF pages 12-13, referring to Exhibit C3-7.

²²² Maissan Final Argument, PDF page 13.

²²³ Transcript, Volume 2, PDF pages 125-127.

7.4 Generation plant

348. AEY provided the following forecast for capital expenditures – Generation from Table 9.2 of the Application:

Table 18: Capital Expenditures – Generation (\$000)

Year	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals							Test Year	
Capital Expenditures	6,944	963	2,147	2,635	3,597	3,050	1,178	3,273	3,352

Source: Exhibit B-1, Application, Table 9.2: Capital Expenditures – Generation, PDF page 174.

349. Factors considered by AEY when reviewing generation capital projects include unit performance, plant obsolescence, planned replacements, load growth, safety requirements, environmental regulations, and integration of renewables.
350. The capital expenditure forecast prepared by AEY uses estimates developed by determining which generation units are due for replacement or necessary upgrades. Costs estimates can include preliminary engineering and design work, historical costs of comparable projects, and results from any tender process.

7.4.1 Views of AEY on generation projects related to Fish Lake (Business cases 32 and 39)

351. As noted above, during the oral hearing, AEY updated its Fish Lake projects detailed in Business Case 32 and Business Case 39 stating they were behind schedule due to procurement issues and would be deferred until 2024.
352. The Board observes that AEY had forecast to capitalize certain portions of Business Case 32 and Business Case 39 into the 2023 rate base — costs in the amount of \$0.452 million in 2023 for “Fish Lake 1 Roof Replacement” and \$0.385 million in 2023 for “Fish Lake 2 Replace Power Station FEED.”²²⁴

7.4.2 Board Findings

353. Consistent with the Board’s findings with respect to any portion of capital expenditure related to Business Case 32 that were capitalized into AEY’s 2023 opening rate base, the Board finds that expenditures forecast to be capitalized during 2023 (in the amounts noted in the previous paragraph)²²⁵ should be removed and shown as a

²²⁴ Exhibit B-10.3, AEY GRA Regulatory Schedules, Omissions & Updates, Blackline, S9.2, Line nos. 3 and 4.

²²⁵ Exhibit B-10.3, AEY GRA Regulatory Schedules, Omissions & Updates, Blackline, S9.2, Line nos. 3 and 4.

capital addition in the year 2024. This direction is based on the testimony provided during the oral hearing (and quoted above),²²⁶ that the projects are behind schedule and that the costs are now forecast to be capitalized into rate base in 2024.

7.4.3 Views of AEY on Remaining forecast generation projects

354. AEY, in its final argument discussed the Replacement of Watson Lake Generating Units and the use of the N-1-1 criteria used only for Watson Lake generation units. As stated by AEY, the N-1-1 criteria is used by Manitoba Hydro and is a recognized principle of several utilities in the North American Off Grid Utilities Association, which association is working on policy for Canadian and North American utilities operating on isolated grids.²²⁷

7.4.4 Views of interveners

355. While several of the intervenors made requests for general reductions, only the UCG commented on specific generation capital projects. They stated that, given the dollars spent on the Fish Lake facility both historically and forecast in the test period, "... it is time to have a full analysis to demonstrate this facility is indeed cost effective, regardless of the reasoning given 'that perpetual control and monitoring of water safely throughout the Fish Lake drainage system regardless of whether electricity is made.'" ²²⁸ (footnote omitted)

7.4.5 Board Findings

356. The Board finds the capital projects identified by AEY for the test period to be reasonable and required. The Board also accepts AEY's use of the N-1-1 criteria for the Watson Lake generating station as it is considered an acceptable principle for use by North American Off-Grid utilities. As noted above, those projects not completed in the 2023 test period are to be moved to the 2024 test year for revenue requirement purposes. The remaining generation capital additions to be added to rate base are approved as requested.

7.5 Distribution plant

357. As shown in Table 19 below, AEY categorizes its distribution capital projects into six categories:

- New extensions
- New extensions - IPP

²²⁶ Transcript, Volume 3, PDF pages 89-90.

²²⁷ Transcript Volume 3, starting at PDF page 99, line 16 to PDF page 100 line 21.

²²⁸ UCG Final Argument, PDF Page 11, paragraph 55. The interior quotes refer to Exhibit B-4, AEY Consolidated IR responses, AEY-UCG-31, PDF pages 961-962

- Distribution improvements
- Street and sentinel lighting
- Meters
- Transformers and regulators

Table 19: Summary of Distribution actual (A), approved (Appr) and forecast (F) capital expenditures for the years 2016-2024 (\$ millions)

	2016A	2017A	2018A	2019A	2020A	2021A	2022A	2023F	2024F	2016 Appr	2017 Appr
Distribution											
New extensions	2.527	3.099	3.990	5.176	3.636	4.247	4.714	5.885	5.216	2.155	3.715
New extensions – IPP	-	-	-	-	-	0.366	1.394	1.115	-	-	-
Distribution improvements	4.103	3.819	2.318	2.634	1.658	3.180	2.028	5.195	9.081	4.335	4.153
Street and sentinel lighting	0.407	0.936	0.553	0.785	1.627	1.055	1.009	2.563	1.042	0.584	0.777
Meters	0.105	0.088	0.032	0.067	0.127	0.075	0.098	0.235	0.410	0.199	0.203
Transformers & regulators	0.324	0.213	0.070	0.262	0.385	0.222	(0.008)	0.928	0.275	0.367	0.091
Total Distribution	7.466	8.156	6.962	8.924	7.434	9.145	9.234	15.920	16.023	7.640	8.939

Source: Exhibit B-10.3 – AEY GRA Regulatory Schedules, S9.2, S9.1 and S8.12.

358. With the exception of the specific distribution projects noted below, the Board has examined the evidence provided and accepts the capital projects identified by AEY for the test period to be reasonable and required. The Board’s findings on those distribution projects not accepted are as follows.

7.5.1 Distribution improvements - Substation Mayo Road and Substation Whistle Bend Leota 229 (Business Case 25)

359. Two projects comprise the applied-for costs detailed in Business Case 25, identified as the Mayo Road and Whistle Bend – Leota substations. The need for these substations arose because the Whitehorse North 25 kV distribution system does not have the capacity to provide needed contingency between the existing substations within the next six-years. The Mayo Road and Whistle Bend - Leota substations will increase overall capacity of the North 25 kV distribution system, providing greater contingency capabilities and increased voltage stability.

229 Also referred to as Whistle Bend 2, or WB2.

360. The forecast cost and in-service dates for the two substation projects is as follows:

Table 20: Mayo Road and Whistle Bend – Leota forecast cost and in-service dates (\$ millions)

	Capital expenditure	Year of capital expenditure	Capital addition	Year of capital addition
Mayo Road substation transformer – procure (Note 1)	0.400	2022	0.400	2022
Mayo Road substation build and commission, and configure new system and salvage regulator bank	2.554	2023	2.554	2023
Whistle bend - Leota substation build	0.154	2023	0.154	2024
Whistle bend - Leota substation build and commission, and configure new system	2.781	2024	2.781	2024

Source: Exhibit B-1.8, Business Case 25, Table 1, PDF page 70; Exhibit B-10.3 GRA schedule S9.2, line nos. 274 and 283. Note 1. The \$0.400 million capital addition for the Mayo Road substation transformer procurement has been addressed earlier in sub-section 7.1 – Opening Rate Base.

361. As noted earlier in sub-section 7.2 of this Appendix A to Board Order 2024-01, during the oral hearing, AEY confirmed that these two substation projects were behind schedule due to land permitting issues and are now not expected to be completed until at least 2024.

7.5.1.1 Views of interveners

362. The UCG argued that, while the two new substations “appear to be justified,” because of the delays, the costs should not be capitalized and placed into rate base in the GRA but held in CWIP until the full costs has been justified and the projects are complete.

7.5.1.2 Board Findings

363. With respect to these two substation projects, the Board agrees with the position of the UCG that AEY’s capital expenditures should remain in CWIP over the 2023-2024 test period. This is because AEY confirmed during the oral hearing that neither of the substation projects were under construction at that time,²³⁰ and AEY has not provided sufficient evidence to persuade the Board that either of the projects can be completed within the 2023-2024 test period given the land permitting issue.

²³⁰ Transcript, Volume 3, PDF pages 83-84.

364. Accordingly, for the Mayo Road Substation, while the quantum of forecast capital expenditures appear reasonable, the Board directs that AEY reflect the \$2.554 million capital expenditure in 2024 rather than in 2023. Further, the Board denies AEY the capitalization of any portion of the Mayo Road Substation within the test years and AEY is directed to remove the associated forecast capital addition for this project from the 2023-2024 test period. At the time of its next GRA, AEY will be able to reflect the Mayo Road Substation capital addition in its 2025 opening rate base, assuming it has been completed by then.
365. For the Whistle Bend – Leota Substation, the Board similarly finds that the quantum of forecast capital expenditures appear reasonable. However, given that construction for this project is not underway, the Board directs that AEY reflect the \$0.154 million capital expenditure in 2024 rather than in 2023. The Board also denies AEY the capitalization of any Whistle Bend – Leota Substation within the test years and AEY is directed to remove the associated forecast capital addition for this project from the 2023-2024 test period. At the time of its next GRA, AEY will be able to reflect the Whistle Bend – Leota Substation capital addition in its 2025 opening rate base, assuming it has been completed by then.

7.5.2 Views of AEY on Distribution improvements – 6L19 Voltage Improvement (Business Case 30)

366. In its Business Case for the 6L19 Voltage Improvement project, AEY outlined issues along the 35kV system south of Whitehorse. These include: low voltage at Teslin and Robinson locations; the number of customers fed off the 35 kV system; and the Lewes River regulators being tapped to their maximum limit for extended periods of time.
367. AEY explained that, normally, low voltage conditions on a typical transmission line would not be an issue due to the ability to step up voltage at a distribution substation. However, given that the sub-transmission system feeds customers as well, the voltage needs to adhere to ATCO distribution voltage standards.
368. Of the six alternatives examined, AEY recommended a multi part approach to combat the low voltage conditions along the 6L19 feeder which included: boosting the source voltage; installing a new 200A regulator bank on a feeder line; and relocating two 100A regulators at Carcross Cutoff and Lewes River. AEY forecast costs and in-service dates as noted in the following:

Table 21: 6L19 Voltage Improvement – project schedule and forecast costs (\$ millions)

	Cost	Target in-service date
Boost S150 Voltage to 1.04 p.u.	0	2024

Install 200 A Regulator Bank on 6L11	0.593	2024
Relocate 100 A Carcross Cutoff Regulator	0.178	2024
Relocate 100 A Lewes River Regulator	0.178	2024

Source: Exhibit B-1.8, Business Case 30, Table 2, PDF page 102; Exhibit B-10.3 GRA schedule S9.2, line nos. 236-238.

369. AEY stated that the undervoltage issues were not fully known until the completion of the applicable technical study in April 2023. Further, any reconductoring required for the Atlin project would not be of assistance with solving the undervoltage issues noted.²³¹

7.5.2.1 Views of interveners

370. Mr. Maissan contended that the low voltage situations at the locations cited by AEY could not have deteriorated without AEY knowing about it well in advance. He criticized AEY saying that the affected customers deserve better than the service they have received in the last few years. AEY should have identified the need for, and thus proposed, the upgrades sooner as the voltage situation must have been known at the time of identifying upgrades required to accommodate the potential Atlin hydro project.²³² Mr. Maissan pointed to AEY's statement that it regularly monitors the overall performance of a line as evidence that the low voltage issues should have been apparent to AEY well before April 2023.²³³
371. Mr. Maissan recommended that the Board approve the 6L19 Voltage Improvement project subject to the upgrades being able to "accommodate and not increase the costs of the upgrades that would be required should the Atlin hydro project proceed in the next several years."²³⁴

7.5.2.2 Board Findings

372. While the Board is cognizant of the concerns raised by Mr. Maissan, there is insufficient information on the record supporting a connection between the upgrades as proposed by AEY and any upgrades that may prove to be required for the Atlin hydro project, whether now, or in the future. AEY's forecast capital expenditures and capital addition for the 6L19 Voltage Improvement project in 2024 is approved.

²³¹ Exhibit B-4, AEY Consolidated IR Responses, AEY-JM-040(a), PDF page 93.

²³² Exhibit B-4, AEY Consolidated IR Responses, AEY-JM-040(a), PDF page 93; AEY-UCG-092(a), attachment 1, PDF page xx.

²³³ Transcript, Volume 1, PDF pages 77-78.

²³⁴ Maissan Final Argument, PDF page 12.

7.5.3 Views of AEY on Distribution improvements – Downtown Whitehorse Capacity Increase (DWCI) – New 12.5kV Substation (no business case provided)

373. AEY's applied-for costs related to the DWCI – 12.5 kV Substation project are in the amounts of \$0.025 million and \$0.792 million for the years 2023 and 2024, respectively.²³⁵
374. During the oral hearing, AEY confirmed that, although some planning work has been completed for this project and the listing of long lead equipment to be ordered has been identified,²³⁶ the substation is slated for construction after the Mayo Road and Whistle Bend substations are completed. AEY also indicated that it was working with the City of Whitehorse to find land upon which to locate the DWCI substation.²³⁷
375. AEY stated that while the costs for this project exceeded the dollar value threshold used by the Board to indicate a need for the preparation of a business case, it did not prepare the business case because it focused more on the fact it would not be capitalized during the test period, as opposed to providing detailed information.
376. AEY indicated that the total project costs anticipated for the DWCI substation would be similar in amount to that of the Mayo Road and Whistle Bend – Leota substation projects, which is approximately \$2.8 million each.²³⁸

7.5.3.1 Board Findings

377. The Board has concerns with AEY's position on the need to file business cases supporting its forecast capital expenditures. AEY's statement that its "intention would be to complete a business case with the technical specifics in advance to the installation of that equipment"²³⁹ implies a lack of forethought concerning planning and budgeting, irrespective of when AEY foresees the project will be completed and added to rate base.
378. The Board will not make a finding, nor direct AEY to file a business case given that it appears to be aware of the Board requirements in that regard. However, the Board cautions AEY that the requirement to support its forecast capital costs, whether a capital expenditure or capital addition, must be given a higher priority in its future applications.

²³⁵ Exhibit B-10.3, AEY GRA Regulatory Schedules, Omissions & Updates, Blackline, S9.2, Line No. 279.

²³⁶ Exhibit B-4, AEY Consolidated IR Responses, AEY-YUB-042, PDF page 1164.

²³⁷ Transcript, Volume 3, PDF page 84.

²³⁸ Transcript, Volume 3, PDF pages 81-82.

²³⁹ Transcript, Volume 3, PDF page 79.

379. In any event, the Board finds that AEY has not provided sufficient specifics with respect to the nature and timing of its forecast 2024 capital expenditures, particularly in light of the Mayo Road and Whistle Bend Substations being delayed. Given the delays it is experiencing on the Mayo Road and Whistle Bend – Leota substations and the fact that AEY has indicated that these will take priority over the DWCI substation, the Board has doubts about AEY’s ability to commence the construction of the DWCI substation during the 2024 test period. The Board therefore directs AEY to remove its 2024 forecast capital expenditures of \$0.792 million in its compliance filing to this Board Order.

7.5.4 Views of AEY on Distribution – Advanced Metering Infrastructure (AMI) Project New Meters (Business Case in AEY-YUB-065(a) Attachment 1)

380. In its application, AEY forecast \$0.132 million and \$0.304 million in capital expenditures related to its Advanced Metering Infrastructure (AMI) Project New Meters in the years 2023 and 2024, respectively.
381. AEY indicated that the roughly \$0.400 million would cover the purchase and installation of materials and integrate the AMI system with AEY’s new CCS system. Additional benefits included the use of AMI as a fundamental building block of AEY’s proposed grid modernization, including the potential to: eliminate the need for a person to physically read a meter for billing purposes; gather meter reads at any required interval; and, allow for real-time monitoring and automated reaction to changing grid conditions.²⁴⁰
382. In response to IRs, AEY submitted a business case stating that it seeks approval for \$0.436 million to implement a fully operational AMI deployment in the Whitehorse area over 2023-2024. Forecast annual O&M costs for license and software as a service fee are \$0.018 million.²⁴¹
383. AEY stated it had not fully forecast savings related to the installation of AMI meters. However, there are anticipated savings related to reduced fleet O&M due to fewer truck calls, lower labour costs as the requirement to physically read the meters lessens, and reduced costs for “rework” meter reads due to extreme weather events. Further, the project itself was limited in scope to approximately 1,500 meters to be located in the Whistle Bend Subdivision.²⁴²

²⁴⁰ Exhibit B-1, Application, PDF pages 22-23.

²⁴¹ Exhibit B-4.1, AEY-YUB-065(a).

²⁴² Exhibit B-4, AEY Consolidated IR Responses, AEY-JM-020, PDF page 52; AEY-UCG-013(c), PDF page 225; AEY-UCG-037, PDF pages 435-436.

384. During the oral hearing, AEY clarified that one meter has been installed in Whistle Bend and that it is reading meters but is not currently integrating with the billing system. The total project spend to August 31, 2023 is \$0.006 million.

7.5.4.1 Views of interveners

385. In argument, Mr. Maissan strongly recommended that the Board approve AEY's AMI metering project. In addition to lowering labour costs, the AMI metering project will be able to accommodate time-of-use billing on AEY's new CCS billing system and it would allow for remote disconnects and connects, and also remote control of connected electrical equipment on customer property. Mr. Maissan focused on the positive attributes of this project as important steps in modernizing the electrical grid management and electrical customer services.²⁴³
386. The UCG argued that the AMI project left unanswered questions ranging from where the pilot project was being tested to why the new meters weren't being installed in all new buildings. The UCG also questioned whether there will be costs to upgrade to newer technology and if there were any considerations of whether replacing meters in old buildings could be achieved by attrition.²⁴⁴

7.5.4.2 Board Findings

387. Generally, the Board considers that if an optimum rollout of the overall AMI project can be achieved, there is a high level of desirability for the project. This is notwithstanding certain details respecting the longer-term phased-in approach for this project were lacking in the information provided by AEY. Specifically, the absence of a cost-benefit analysis prevents the Board from fully endorsing the applied-for costs at this time. This is particularly relevant given the issues AEY is currently experiencing with the single installed meter.
388. During the oral hearing AEY explained there had been no success with the AMI project's single installed meter and its ability to interface with AEY's new billing system. This results in uncertainty as to how this critical function will be achieved and at what cost. Given the importance of this aspect of the AMI project, the Board directs AEY to provide an update on the project at its next GRA, specifically addressing these issues, how they have been resolved, and the cost of resolving them.
389. The Board approves, for 2023, an amount equal to AEY's actual 2023 capital expenditures of \$0.006 million with the balance of forecast costs (being \$0.430 million of the total \$0.436 million 2023-2024 forecast capital expenditures) to be recorded in the year 2024. However, the Board declines to approve the capitalization of any amount of these costs into AEY's 2023 or 2024 rate base at this time.

²⁴³ Maissan Final Argument, PDF pages 11-12.

²⁴⁴ UCG Final Argument, PDF page 12.

Accordingly, to the extent that AEY has forecast any capital additions for 2023-2024 for the AMI project, the Board directs that these costs be removed. When AEY is better able to articulate the costs and benefits of this project over the longer-term phased-in period including the AMI meter’s ability to interface with AEY’s new billing system, the Board will re-examine the information provided by AEY to determine the prudence of the 2023-2024 capital expenditures and whether further capital expenditures have been justified and are thus warranted.

7.5.5 Views of AEY on Distribution – Street and sentinel lighting

390. AEY discussed Street and Sentinel Lights in Section 9.5 of the Application. The following forecast for Street and Sentinel Lights was provided by AEY:

Table 22: Street and Sentinel Lights (\$000)

	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals							Test Year	
Capital Expenditures	407	936	553	785	1,627	1,055	1,099	2,563	1,042

Source: Exhibit B1, Application, Table 9.5: Capital Expenditures – Street and Sentinel Lights, PDF page 177.

391. AEY explained that expenditures are required to provide new street and sentinel lighting in AEY’s service area. Streetlight replacements are included in this category. The forecast is based on known areas of development in the communities, as well as a review of historic replacement requirements.

7.5.5.1 Views of interveners

392. Parties did not provide any comments on street and sentinel lighting.

7.5.5.2 Board Findings

393. In response to an IR, AEY’s year-to-date costs (August 2023) for streetlights were a net credit (after contributions) of (\$298,276).²⁴⁵

394. Based on AEY’s historical spend on street and sentinel lighting and AEY’s spend-to-date (August 2023), the Board is concerned with AEY’s ability to complete all street and sentinel lights as forecast before the fiscal year-end. For the compliance filing to this Board Order, AEY is directed to use the actual 2023 capitalized into rate base amounts²⁴⁶ for street and sentinel lights, for the compliance filing to this Board Order.

²⁴⁵ Exhibit B-4, AEY Consolidated IR Responses, AEY-YUB-064(a), PDF page 1291.

²⁴⁶ The context for capitalized amounts in this case refers to assets that are in service and ready for use on or before December 31, 2023.

The Board accepts the 2024 forecast amounts for street and sentinel lighting as reasonable.

7.6 General property plant & Equipment (GPE)

395. AEY discussed GPE in Sections 9.7 and 9.8 of the Application. AEY provided the following forecast for General Property and Equipment (GPE):

Table 23: Capital Expenditures – General Property and Equipment (GPE) (\$000)

	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals							Test Year	
Capital Expenditures	374	1,150	303	962	883	1,621	4,753	5,547	3,263

Source: Exhibit B-1, Application, Table 9.7, Capital Expenditures – General Property and Equipment, PDF page 178.

396. AEY explained that GPE includes such items as tools, office furniture, office computer equipment and software communication equipment, transportation equipment, lands and buildings. Schedule S9.1 provides a breakdown of GPE by major category type. AEY submitted that forecast estimates are developed by identifying whether the needs are for upgrade, replacement or new acquisition. It added that cost estimates are developed based on historical and market prices. When required engineering studies/business cases are completed to demonstrate the selection of the most reasonable alternative.

7.6.1 Views of AEY on GPE - ATCO CIS replacement project (Business Case 22)

397. AEY stated that the ATCO CIS was at the end of its useful life and required replacement. The selection of the replacement for ATCO CIS was undertaken through a tender process. AEY chose the Oracle Customer Cloud Service Solution (CCS) as the replacement for ATCO CIS. The decision was based on Oracle CCS being the lowest cost alternative and having additional functionality. The ATCO CIS replacement project was completed and in service in 2023.²⁴⁷

7.6.1.1 Views of interveners

398. The UCG noted that, like some other projects, the ATCO CIS replacement does not have direct benefits to ratepayers proven in the evidence, is intangible, and should not be allowed in rate base.²⁴⁸

²⁴⁷ Transcript, Volume 1, PDF page 107.

²⁴⁸ UCG Final Argument, PDF pages 8-9, paragraphs 39-42.

7.6.1.2 Board Findings

399. The Board accepts the position of AEY that ATCO CIS was at end of life and needed replacement. Further, the Board accepts the evidence of AEY that the Oracle CCS was the lowest cost option for this project and also provides increased functionality. Therefore, the Board approves the forecast ATCO CIS replacement project costs to be included into rate base as filed by AEY.

7.6.2 Views of AEY on GPE – Asset Management Project (Business Case 24)

400. AEY included Business Case 24²⁴⁹ in support of its Asset Management (AS) program. AEY stated: “Starting in 2023 and continuing into 2024, AEY is proposing to begin implementation of this five-year roadmap with the priorities that have been identified.”²⁵⁰
401. Business Case 24 referred to Attachment 1 and Table 2-1 contained in the business case to identify the benefits of the proposed AS system. Attachment 1 is an AS Assessment undertaken by METSCO Energy Solutions Inc. (METSCO report).
402. AEY proposed to spend \$0.318 million on the AS system in 2023, and a further \$0.901 million on the AS system in 2024. AEY said: “So these costs in this business case are for the first two years. It's a five-year implementation for the asset management program, so there would be further costs to develop the plan.”²⁵¹
403. In argument, AEY stated that it “expects that the implementation of an Asset Management program would provide AEY with cost savings as a result of risk mitigation, as well as improved system reliability. AEY anticipates benefits from the project will be of a qualitative nature.”²⁵² (footnotes omitted)

7.6.2.1 Views of interveners

404. The UCG noted that, like some other projects, the AS project does not have direct benefits to ratepayers proven in the evidence, is intangible, and should not be allowed in rate base.²⁵³

7.6.2.2 Board Findings

405. The Board finds that the METSCO report provided generalizations and did not describe any specific quantifiable benefits specific to AEY. Further, when the Board asked about the five categories listed in the METSCO report and requested examples

²⁴⁹ Exhibit B-1.8, Business Cases 22-38, PDF pages 12-66.

²⁵⁰ Exhibit B-1.8, Business Cases 22-38, PDF page 13.

²⁵¹ Transcript, Volume 2, PDF page 77, lines 3-6.

²⁵² AEY Final Argument, PDF page 45, paragraph 127.

²⁵³ UCG Final Argument, PDF pages 8-9, paragraphs, 39-42.

of where AEY has failed to meet reliability measures, where customer service has been negatively impacted, or where AEY has incurred additional costs because it did not implement the AS program, AEY did not provide any examples.²⁵⁴

406. As noted above, AEY has identified costs for the first two years of the five-year roadmap, and stated there would be operating costs involved but currently cannot quantify those costs.²⁵⁵ Further, AEY has not submitted the full capital costs for the entire project or provided estimates of annual operating costs. All benefits have been identified as qualitative and mid to long term in nature. AEY has been unable to identify any specific revenue requirement savings from this project. AEY is asking for approval to commence a project with unknown final costs and uncertain benefits. In other words, AEY is asking rate payers to pay for a project with unspecified total costs, unspecified financial benefits, and only possible long-term intangible benefits. This represents a risk that ratepayers should not be asked to take. For these reasons, the Board cannot approve this project until such time as the costs and benefits of this project are more quantifiable and specific to AEY. The Board directs that all costs for the AS project be removed from the revenue requirement for AEY in its compliance filing to this Board Order.

7.6.3 Views of AEY on GPE – Salesforce (Business Case in AEY-YUB-066(b) Attachment 1)

407. Salesforce is a project management system. AEY included costs for Salesforce Business analysis. The project consists of 3 phases, with Phase I and II being completed in the two test years of this GRA. AEY will make a final determination and implement a solution in Phase III in 2024. The project costs during the test years of this GRA are \$0.048 million for Phase I and \$0.124 million for Phase II. The business case for the project was submitted in a response to an IR.²⁵⁶

7.6.3.1 Views of interveners

408. No specific comments were provided on this project.

7.6.3.2 Board Findings

409. The Board finds the costs for Phase I and II of this project to be reasonable and understands the benefits of a system to better manage projects and the development of KPIs to measure progress. The Board approves the forecast costs for Phase I and II of this project as requested by AEY. The Board will not approve Phase III of the project

²⁵⁴ Exhibit B-4, AEY Consolidated IR Responses, AEY-YUB-068, PDF pages 1300-1301.

²⁵⁵ Transcript, Volume 2, PDF page 77, lines 11-16.

²⁵⁶ Exhibit B-4.1, AEY-YUB-66(b) Attachment 1, PDF pages 14-18.

until KPIs are developed and an explanation of how those KPIs will be measured are provided to the Board.

7.6.4 Views of AEY on GPE – Tools and Transportation (Business Cases 1, 2, 3 and 4)

410. In Schedule 9.1 for 2023, AEY forecast capital expenditures of \$0.310 million on tools and \$0.697 million on transportation equipment. The amount forecast for tools is significantly higher than historical capital spends on tools. Similarly for transportation equipment, other than the spend on the immediate two years preceding the test period, the capital spend on transportation equipment has been lower.
411. AEY provided a business case on transportation equipment, but no detailed explanations were provided for tools expenditures.

7.6.4.1 Views of interveners

412. Intervenors did not comment on these GPE items.

7.6.4.2 Board Findings

413. Based on AEY's historical spend on these GPE categories and noting lagging supply issues as a remnant of the COVID-19 pandemic, the Board is concerned with the increases in the capital spend for these two items and AEY's ability to acquire all those assets before the fiscal year-end. In its compliance filing to this Board Order, AEY is directed to use actual 2023 capitalized amounts²⁵⁷ for tools and transportation equipment. The Board accepts the 2024 forecast amounts for these two cost categories as reasonable.

8 Income Tax

8.1 Views of AEY

414. AEY discussed income tax in Section 10 of the Application. In that section AEY stated that it continues to use the flow-through method in calculating income tax expense. AEY attempts to minimize taxable income by claiming the maximum of all available deductions, including capital cost allowance, and does not book deferred income taxes.
415. Parties did not provide any comments on income taxes.

²⁵⁷ The context for capitalized amounts in this case refers to assets that are in service and ready for used on or before December 31, 2023.

8.2 Board Findings

416. The Board notes that AEY continues to use the flow-through method in calculating income tax expense. The Board accepts this method of calculating income taxes. However, the Board notes AEY will have to recalculate its income tax expense in the compliance filing to this Board Order to reflect the changes AEY must undertake to comply with the directions in other parts of this decision. AEY is directed to undertake that recalculation of income taxes in its compliance filing to this Board Order.

9 Deferral and reserve accounts and no-cost capital account²⁵⁸

9.1 Views of AEY

417. In its Application, AEY proposed deferral-account treatment for two new cost categories — as reserve or deferral accounts or as a no cost capital account — while maintaining consistent treatment for those categories previously approved by the Board. AEY's summary of existing and proposed reserve and deferral accounts is shown in the following table.

Table 24: Summary of existing and proposed deferral and reserve accounts

Name of existing or proposed deferral and reserve accounts	Existing account	Proposed account	Regulatory Schedule	Section/location in Application
Reserve account				
Rate case costs	X		Schedule 8.8 Line No. 19-26	Section 8.3.3
Reserve for injuries and damages (treated as no cost capital)	X		Schedule 8.4 Line No 26-32	Section 8.2.6
Other Post Employment Benefit (OPEB) (treated as no cost capital)	X		n/a	Section 8.2.6

²⁵⁸ AEY's deferral and reserve accounts are tracked on GRA Schedule 8.8 – Continuity of Deferred Charges & Credits, and netted against AEY's rate base calculations on GRA Schedule 8.5 – Computation of Rate Base. These deferred charges & credits are comprised of any balances in AEY's Rate case account, Watson Lake LNG study cost account, Demand side management program account, Pension deferral account and ERA/IPP legal cost account.

AEY's no cost capital accounts are tracked on GRA Schedule 8.4 – Continuity of No Cost Capital, and also netted against AEY's rate base calculation and thus AEY's calculation of return on GRA Schedule 8.1 – Return on Rate Base. These no cost capital balances are comprised of any outstanding amounts related to AEY's Other post-employment benefits account, Defined benefit pension account and Reserve for injuries and damages account.

Deferral account				
Industrial Rider R flow through	X		Schedule 13.1	Section 2
Purchase power flow-through	X		Schedule 3.1	Section 3
Diesel fuel	X		Schedule 4.1	Section 4
Feasibility study or program: Watson Lake LNG Study Costs	X		Schedule 8.8 Line No. 28-35	Section 8.3.3
Demand side management (DSM)	X		Schedule 8.8 Line No. 37-44	n/a
Pension deferral account	X		Schedule 8.8 Line No. 46-52	Section 8.3.3
Board order or changes in legislative provisions		X	Not included	Section 1B
Independent power producer (IPP) flow through		X	Schedule 8.8 Line No. 54-60	Section 3

Source: Prepared from information in Exhibit B-4, Consolidated IR responses, AEY-YUB-002(b) Attachment 1, PDF page 1020. Reference to Application section and OPEB were added by Board.

9.1.1 Board Findings

418. Referring to the above table, with respect to AEY's existing reserve and deferral accounts, and its reserve for injuries and damages and OPEB accounts, which are treated as no cost capital, the Board finds that their respective intent and scope have not changed. AEY's existing reserve and deferral accounts continue to be approved notwithstanding any specific Board comments respecting various deferral accounts as provided in the sub-sections which follow.
419. Further, the Board has examined AEY's proposed accruals, write-offs, and amortizations as applicable to each existing deferral, reserve, or no-cost capital account, and finds them to be reasonable. These amounts are approved subject to any applicable Board findings or directions found elsewhere in this Board Order.
420. In the following sub-sections, the Board will discuss various aspects of four of AEY's existing deferral accounts. The Board also addresses the two new deferral account categories proposed in AEY's application and determines whether they should receive deferral-account treatment.

9.2 Industrial Rider R deferral account

421. AEY does not serve any industrial customers. However, AEY requests continuation of the Industrial Rider R deferral account approved in Board Order 2022-13, which is based on YEC's forecast of industrial sales. The deferral account will true up any

variances between YEC's actual and approved industrial sales forecast in future rider applications.²⁵⁹

422. Mr. Maissan supported continuation of the deferral account as directed by the Board in Board Order 2022-13.
423. AEY replied to Mr. Maissan's argument by clarifying: "Because YEC's industrial revenue forecast has been factored into AEY's GRA Rate Adjustment Rider R, the Industrial Rider R Deferral Account balance will be based on the difference between forecast Industrial Rider R revenue and actual Industrial Rider R revenue, and not based on the entirety of YEC's Industrial sales ...".²⁶⁰

9.2.1 Board Findings

424. The Board agrees with the submissions of AEY regarding the Industrial Rider R deferral account and approves the continued use of this account as filed.

9.3 Purchase Power Flow Through Deferral Account

425. AEY requested continuation of the Purchase Power Flow-Through Deferral Account (PPFTDA) in Section 3.3.1 of the application.²⁶¹

9.3.1 Board Findings

426. The Board finds the continuation of the PPFTDA is reasonable and approves the continued use of this deferral account.

9.4 Diesel fuel deferral account

427. In Section 4 of the Application, AEY has requested continuation of the Diesel Fuel Deferral Account. The deferral account measures the variance between actual and forecast fuel prices. AEY described the operation of the account as:

The previously approved methodology for the fuel deferral uses Board approved community-based plant efficiencies (or 'heat rate', kWh/Litre) and the plant's monthly gross generation to determine the quantum of litres for the monthly fuel deferral calculation. The difference between the actual and Board approved price per litre is then applied to this number of litres to arrive at the fuel deferral amount for the month.²⁶²

²⁵⁹ Exhibit B-1, Application, PDF page 31.

²⁶⁰ AEY Reply Argument, PDF page 10, paragraph 24.

²⁶¹ Exhibit B-1, Application, PDF page 108.

²⁶² Exhibit B-1, Application, PDF page 112.

428. Mr. Maissan supported the continued use of the Diesel Fuel Deferral Account. No parties opposed the continuation of the diesel fuel deferral account, and no evidence was submitted suggesting the previously approved deferral account was not operating as intended.

9.4.1 Board Findings

429. The Board accepts the submission from AEY for the continued use of the Diesel Fuel deferral account as reasonable and approves the continuation of the Diesel Fuel deferral account as previously approved.

9.5 Views of AEY on Demand side management (DSM) program deferral account

430. As noted in Table 22 above, AEY currently has Board-approval for deferral treatment for DSM program costs. This is notwithstanding that Board Order 2017-01 approved²⁶³ AEY's request to amortize, as a component of depreciation expense, certain DSM program study costs, consistent with those program study costs being added to rate base (rate base and amortization treatment).
431. While the Board accepted, in Board Order 2017-01, the rate base and amortization treatment as requested by AEY, in the intervening years since that approval and in the absence of AEY submitting a GRA, the amortization of those DSM program study costs continued to be recorded on an ongoing basis. In AEY's current application, AEY noted that since implementing Board Order 2017-01, the DSM program study costs at issue were now over-recovered by approximately \$0.563 million. AEY requested to refund these costs to ratepayers as a reduction to depreciation expense in 2023.²⁶⁴ After 2023, AEY's GRA schedules show no further amortization of DSM program study costs.²⁶⁵
432. During the oral hearing, AEY confirmed that the rate base and amortization accounting treatment requested in its 2016-2017 GRA was "overcomplicated"²⁶⁶ and recommended that, in the future, "all deferral costs be accounted for and settled through the amortization of deferred charges schedule,"²⁶⁷ (deferred charge and amortization treatment). While cost recovery would be the same under a rate base and amortization approach as compared to a deferral and amortization approach, the

²⁶³ Board Order 2017-01, Appendix A, Reasons for Decision, paragraph 422, PDF 86.

²⁶⁴ Exhibit B-6, AEY-YUB-02-002(a), PDF page 33.

²⁶⁵ Exhibit B-10.3, AEY GRA Regulatory Schedules, Omissions & Updates, Blackline, S7.3.

²⁶⁶ Transcript, Volume 4, PDF page 78, lines 12-21.

²⁶⁷ Exhibit B-6, AEY-YUB-02-002(a), PDF page 33.

latter method has a consistent settlement mechanism and would eliminate any further confusion.

9.5.1 Board Findings

433. As noted in sub-section 5.6 above (in respect of AEY's depreciation expense), the Board accepted AEY's proposal to refund approximately \$0.563 million of over-recovered DSM program study costs to ratepayers as a reduction to its 2023 depreciation expense in 2023.
434. In this section, the Board accepts AEY's recommendation that all future deferred costs of a similar nature to those at issue here, should be applied for and accounted for within AEY's currently-approved deferral account mechanism.

9.6 Views of AEY on Board Orders or changes in legislative provisions deferral account

435. In the Application, AEY stated:

... there are plans from both the Federal (Canadian Net-Zero Emissions Accountability Act) and Territorial (Our Clean Future) Governments aimed at lowering carbon emissions and increasing electrification over the next several decades. With these new legislative requirements and quickly developing plans and strategies comes a significant amount of uncertainty and complexity for electric utilities.

AEY seeks the ability to flow-through (dollar for dollar) costs and savings related to Board Orders or legislative provisions resulting in changes to the rules or parameters under which AEY operates, or that impact the nature and extent of AEY's obligations as a regulated utility, and which impact its 2023-2024 revenues or revenue requirement.

AEY submits that this deferral account is required in light of the various initiatives currently being considered and implemented throughout the Yukon (for example – EV expansion, flow through of carbon credits/rebates and MG). This deferral account would address any future Board orders or legislative provisions that bring about savings to customers or impact AEY's ability to recover its prudently incurred costs.²⁶⁸

436. In argument AEY stated:

The Board previously declined to approve AEY's requests for a Board Orders and Legislative Changes deferral because of its view that, given stakeholder input and lead time associated with legislative changes, AEY would have sufficient time to incorporate any such changes into a GRA filing. In AEY's

²⁶⁸ Exhibit B-1, PDF pages 23-24, paragraphs 17-19.

submission, this does not adequately consider: (i) that AEY cannot be aware of or involved in all changes taking place; (ii) that even if AEY is involved, it is not the driver or ultimate decision-maker behind such initiatives; (iii) that energy transition policies are not implemented and changed on regular or predictable timelines; and (iv) that GRA proceedings involve significant lead time and expense.²⁶⁹ (footnote omitted)

9.6.1 *Views of interveners*

437. Mr. Maissan argued:

... AEY is, and has for many years been, subject to regulation and Board Orders under existing legislation, this is the environment in which they do business, and it is inappropriate that there be a deferral account that deals with Board Order concerns that AEY may have.

...

In my view there is probably some cause for concern by AEY that the legislative environment may change rapidly. However, as noted during the hearing the IPP and Micro-Generation policies have been around and AEY has been dealing with them for a number of years (Tr Vol 1, p35 L17 to p36 L7; and Vol 3, p75 L8-15). Based on AEY witnesses the effect of the micro-generation program has been embedded into the sales forecast and unless there is a significant rate of change there would be no material impact (Tr Vol 1, p99 L17 to p100 L10). The IPP issues are addressed under a separate proposed deferral account.

With respect to other federal and Yukon legislative changes, including for electric vehicle (EV) chargers, these have come with funding attached (Application p1B-3). If AEY is not paying for this infrastructure and they stand to gain incremental sales, there is negligible risk for them.

Grid modernization and grid capacity increases are achieved through capital projects which are brought before the Board in GRAs and approved or disallowed by the Board and do not require deferral accounts.²⁷⁰

9.6.2 *Board Findings*

438. AEY has previously requested approval for a deferral account regarding Board Orders and legislative changes. The Board accepts the submissions of Mr. Maissan that AEY is in an environment that is subject to regulation and Board Orders, and has existed in that environment for many years. In addition, the Board finds that the micro-generation program has been embedded into the sales forecast, minimizing the impact of this program. In addition, the Board assesses grid modernization and grid capacity changes through the reviews of the utility's capital program. Legislative

²⁶⁹ AEY Final Argument, PDF pages 9-10, paragraph 20.

²⁷⁰ Maissan Final Argument, PDF page 3.

changes usually have long lead times and can be addressed through timely general rate applications (which are under the control of AEY). Further, the Board took note that when asked if Board Orders have impacted AEY's revenue requirement, AEY responded: "Board Orders have typically not impacted AEY's revenue requirement in the past."²⁷¹ In that same IR, AEY was asked: "Have any legislative provisions impacted AEY's revenue requirement set for a test year without a new subsequent proceeding?"²⁷² AEY did not directly respond to the question.

439. AEY has not demonstrated a financial impact as a result of Board Orders or legislative changes. Further, it is the Board's view that AEY has significant opportunity to either participate in proceedings that have determinations that may impact AEY or opportunity to consult with governments of various levels on policies that may have an impact on AEY. The Board denies AEY's request for a Board Orders or Legislative Provisions Deferral Account.

9.7 Views of AEY on IPP Flow-Through

440. AEY discussed the IPP Flow-Through Deferral Account in Section 3.4 of the Application. To meet the directions of OIC 2019/25, AEY stated Electricity Purchase Agreements are required to provide clarity and certainty to contracting parties. To ensure IPPs were not unfairly put at risk of poor system availability, constraint payments are required. Constraint payments "occur when the IPP is producing power and, due to circumstances outside the IPP's control, an incident occurs that results in the inability of the IPP to access AEY's grid and sell power to AEY."²⁷³
441. If constraint condition happens, based on the EPA (Electricity purchase agreement), AEY must pay the IPP a minimum energy purchase. In addition, AEY must then run its diesel to cover the load not being supplied by the IPP. AEY is also responsible for the maintenance of the BESS, Microgrid controller (MGC) and distribution interconnections of the IPP projects. AEY stated there is uncertainty regarding those costs. Due to the uncertainty around the constraint payments, maintenance costs for the BESS, MGC, and distribution interconnections, AEY is asking for deferral account treatment for those identified costs.
442. In reply argument, AEY clarified the costs to be included in the deferral account:

AEY is seeking approval of the proposed IPP deferral account, which is intended to provide deferral treatment for the following costs, contemplated under section 2 of OIC 2019/25:

²⁷¹ Exhibit B-4, AEY Consolidated IR Responses, AEY-YUB-001(d), PDF page 1016.

²⁷² Exhibit B-4, AEY Consolidated IR Responses, AEY-YUB-001(d-f), PDF pages 1015-1018.

²⁷³ Exhibit B-1, Application, PDF page 109.

- i) Constraint payments paid to IPPs in accordance with the requirements under the EPAs applicable to IPP projects;
- ii) Maintenance costs related to IPP projects; and
- iii) Third party consulting costs (including legal costs) incurred by AEY related to the development and implementation of the EPAs.²⁷⁴

9.7.1 *Views of interveners*

443. Mr. Maissan recommended “the Board approve an IPP deferral account to flow through to ratepayers the constraint payments, the maintenance on the BESS system, and the maintenance on the microgrid controller only.”²⁷⁵

444. YEC commented:

Section 2(2)(c) of OIC 2019/25 provides for AEY cost recovery through rates for maintenance costs of AEY-owned BESS and MGC infrastructure developed for (and initially funded by) IPP projects. AEY states that it needs to own the BESS and MGC for these isolated thermal community IPPs when this infrastructure is “grid forming” equipment enabling diesel off operation. In particular, the BESS, during diesel off scenarios, is responsible for management of system voltage and frequency (which is a utility responsibility), and the MGC is responsible for system coordination between AEY’s power plant and the IPPs renewable generation site (see Undertaking #1, item “g”). Diesel off operation also increases economic and emission reduction benefits derived from IPP generation (since the utility is required to pay for all IPP generation that can be delivered, and diesel off capability increases the diesel reduction secured from this IPP generation), and it also provides social benefits in the community through reduction in diesel plant operation and noise.

The expectation for IPP deferral accounts is that accounting will be trued-up in the next GRA, with all costs still subject to review by the Board as to reasonableness.²⁷⁶ (footnote omitted)

9.7.2 *Board Findings*

445. The Board notes that the costs AEY seeks to include in this deferral account are consistent with OIC 2019/25 Sections 2 and 5. Sections 2 and 5 state that the Board must allow the utility to recover: costs for purchasing electricity under an EPA; third party consulting costs in relation to the development of an EPA; the cost of replacing or maintaining assets to purchase electricity under the EPA; and reasonable compensation to the IPP owner for undelivered electricity to the utility due to

²⁷⁴ AEY Reply Argument, PDF page 16, paragraph 36.

²⁷⁵ Maissan Final Argument, PDF page 6.

²⁷⁶ YEC Final Argument, PDF page 6.

infrastructure or equipment failure that the utility is responsible for. The last item is known as a constraint payment. The criteria for a deferral account as proffered by AEY are as follows:

- a) The cost is not under the control of management or are not reasonably forecastable; or
- b) A variance in forecasting could produce a loss or gain of a substantial magnitude.²⁷⁷

446. The Board considers that a deferral account protects the utility and ratepayers by ensuring that interested parties are able to further scrutinize costs at the time of the deferral account disposition. Further, the deferral account is a tool that ensures ratepayers pay no more than the actual costs and the utility is not subject to forecast gains or losses for any amounts covered by the deferral account.

447. The Board finds costs that AEY has identified as part of the IPP deferral account to be consistent with OIC 2019/25, and to be reasonable. The Board approves the IPP deferral account as requested by AEY.

10 Previous board directions

448. In Section 11 of its application,²⁷⁸ AEY provided responses or a reference to its responses to the applicable Board directions from Board Order 2017-01, Appendix A. The Board has summarized its directions and AEY's response in the following table.

Table 25: Board-prepared summary of AEY's responses to Board Order 2017-01, Appendix A.

Board Order 2017-01 Direction	Summary of Board direction	Summary of AEY response to Board direction
Direction No. 6, Paragraph 123	The Board directed AEY to provide in all future GRAs a labour schedule showing total labour costs as well as a breakdown of those labour costs into capital and each of the O&M and A&G functions. It is to be provided for each of the test years and the three years prior to the test period. The prior periods will show a labour comparison between forecast and actual.	AEY provided Schedule 5.2 of the O&M detailed breakdown by activity.
Direction No. 7, Paragraph 124	The Board directed AEY to provide a schedule in future GRAs, showing labour, fringe and other, comparing actual to approved or forecast levels. Variance explanations provided in Schedule 5.2 should also be provided at the labour, fringe and other levels for all future GRAs.	AEY provided the information in Schedule 5.2, noting that as AEY uses standard labour rates there is no breakout of fringe as it is embedded in the rates.

²⁷⁷ Exhibit B-1, Application, PDF page 13.

²⁷⁸ Exhibit B-1, Application, PDF pages 183-186.

Direction No. 13, Paragraph 172	With respect to AEY's amortization of reserve differences calculation, the Board directed AEY in its future applications, to ensure all supporting schedules filed are consistent with and reflective of Board Orders.	AEY's supporting schedules are consistent with and reflective of Board Orders.
Direction No. 16, Paragraph 278	With respect to its previous GRA, the Board directed AEY to file all KPI reports that it has filed with the Board after the record closed. AEY was also directed to include a list of deficiencies for each of its improvement projects and articulate the same.	AEY provided Attachment 11.2 which breaks down, by project, the System Performance projects into two categories, "Preventative" and "Corrective." For the Preventative projects AEY included the driver which led to the system improvement work being required and for the Corrective AEY included the KPI's pre and post improvement.
Direction No. 20, Paragraph 384	AEY was directed to provide an updated business case for the McIntyre Substation rebuild in its next GRA	AEY submitted Business Case 1: McIntyre Subdivision rebuild.
Direction No. 21, Paragraph 385	If AEY's proposal for alternative 2 (a hybrid system) is explored and is to be implemented, AEY was directed is to include in its updated business case any revised forecast costs and cost savings.	AEY submitted Business Case 1: McIntyre Subdivision rebuild.

Source: Exhibit B-1, AEY 2023-2024 application, PDF pages 183-186.

449. Having reviewed the information provided by AEY in its responses to the above noted directions from Board Order 2017-01, Appendix A, the Board is satisfied that AEY has responded to all outstanding directions.

Appendix 1 — Summary of AEY-proposed and Board-approved Average Service Life and Iowa Curve (life-curve) and Net Salvage (NS) depreciation parameters

Account Number	Description of Account	Proposed Life-curve	Approved Life-curve	Proposed NS per cent	Approved NS per cent
	Generation - Hydro				
331 00	Structures And Improvements	70-R2	70-R2	-5%	0%
332 00	Reservoirs, Dams and Waterways	100-R3	100-R3	-5%	-2%
333 00	Water Wheels, Turbines and Generators	85-R3	85-R3	-5%	-2%
334 00	Accessory Electric Equipment	40-R2.5	40-R2.5	0%	0%
335 00	Miscellaneous Power Plant Equipment	51-R4	51-R4	-5%	0%
	Generation - Diesel				
341 20	Int Combust Structures	40-R2	40-R2	-10%	-1%
342 20	Int Combust Fuel Holders, Producers and Accessories	40-R3	40-R3	-15%	-1%
343 20	Int Combust Generators	26-S2	26-S2	-10%	-5%
345 20	Int Combust Accessory	35-R3	35-R3	-10%	0%
346 20	Int Combust Miscellaneous	40-R3	40-R3	5%	-2%
347 20	Renewables Energy Storage	25-R3	25-R3	0%	0%
	Transmission				
353 00	Station Equipment	50-R3	50-R3	0%	0%
	Distribution Plant				
360 10	Land Rights	75-R3	75-R3	0%	0%
362 00	Station Equipment	40-R2.5	40-R2.5	-10%	0%
362 10	System Communication and Control	15-SQ	15-SQ	-10%	-1%
364 00	Poles, Towers and Fixtures	50-R2	50-R2	-50%	-20%
365 00	Overhead Conductors and Devices	50-R3	50-R3	-25%	-5%
365 10	Overhead Services	50-R2.5	50-R2.5	-10%	-8%
367 00	Underground Conductor and Devices	50-R3	50-R3	-25%	-10%
367 10	Underground Services	50-R4	50-R4	-5%	-5%
368 00	Line Transformers	45-R2.5	45-R2.5	-10%	-10%
370 00	Conventional Meters	15-R0.5	15-R0.5	-5%	-2%
371 00	Automated Meters	15-R2.5	15-R2.5	0%	0%
373 00	Street Lights	30-R3	30-R3	-10%	-10%
373 10	Sentinel Lights	23-R2	23-R2	10%	10%
	General Plant				
390 00	Structures And Improvements	40-L3	40-L3	-10%	-5%
390 01	Structures And Improvements Houses	40-R3	40-R3	-10%	0%
391 00	Office Furniture and Equipment	15-SQ	15-SQ	0%	0%
391 10	Computer Hardware & Voice and Data Network Equipment	5-SQ	5-SQ	0%	0%
391 22	Computer Software and Applications Major (10 Yr)	10-SQ	10-SQ	0%	0%
392 20	Transportation Equipment, Fleet Vehicles Category 2	12-L3	12-L3	10%	10%
392 30	Transportation Equipment, Fleet Vehicles Category 3	15-L3	15-L3	0%	0%
394 00	Tools, Shop, Garage, Stores and Laboratory Equipment	15-SQ	15-SQ	0%	0%
392 40	Transportation Equipment, Fleet Vehicles Category 4	12-L0	12-L0	0%	0%

Source: Exhibit B-10.3 – AEY GRA Regulatory Schedules, S7.2 provides AEY's proposed Life-curve and NS per cent depreciation parameters.

Appendix 2 – Summary of Directions

This section is provided for the convenience of readers. In the event of any difference between the directions in this section and those in the main body of the decision, the wording in the main body of the decision shall prevail.

1. However, the Board accepts the change in sales forecasting methodology for this test period. That is, the effect of the COVID-19 pandemic on forecast sales for the years 2020-2022 can be considered an outlier. Thus, the exclusion of the years 2020-2022 for determining the five-year average UPC growth rates is a reasonable measure taken by AEY in developing its sales forecast for the 2023-2024 test period. However, the Board directs AEY, in its next GRA, to revert to the methodology approved by the Board in AEY's 2016-2017 GRA. Paragraph 28
2. The Board accepts the 2023 full-year forecast of power purchases (351.2 GWh) as provided by YEC because the Board considers the YEC's current (2023) full-year forecast as the most accurate for the 2023 test year. AEY is directed to use this amount for its forecast purchase power and is directed to reflect such in its compliance filing to this Board Order. Further, AEY is directed to adjust its forecast of other supply options to reflect the level of power purchases as reflected in this decision. That is, AEY is to adjust its other supply options but not the level of its sales forecast. Paragraph 38
3. For the year 2023, AEY is directed to remove the forecast labour costs associated with those FTEs in its compliance filing. AEY may include prorated costs for these two FTEs in its 2024 O&M forecast if AEY confirms that these positions have been filled at the time of its compliance application to this Board Order. If these positions have not been filled at that time, the Board directs AEY to remove the forecast labour costs associated with them in its 2024 O&M forecast. Paragraph 62
4. The Board directs AEY, in its compliance filing to this Board Order, to remove all costs from its 2023-2024 revenue requirement that are linked to any sponsorship of community events which, at the time of the oral hearing, AEY estimated to be in the amount of \$0.005 million in Account 70100. As the Board considers these costs to be non-regulated, it directs AEY, in this and each future GRA, to provide assurance that these costs have not been included within any account or cost category of AEY's revenue requirement. Paragraph 70
5. The Board finds that AEY has not supported its 2024 non-labour forecast costs in Account 70200 General Public Information. Given that the costs incurred in 2023 appear to be one-time in nature, and applicable only to the year 2023, the Board finds AEY's 2024 forecast of \$0.072 million to be unreasonable. The Board directs AEY, in its compliance filing to this Board Order, to remove \$0.050 million from its 2024 forecast non-labour costs in Account 70200 - General Public Information. The resulting \$0.022 million is in line with AEY's actual 2022 Account 70200 General Public Information expenditures. Paragraph 74

6. For these reasons, the Board does not accept AEY's 2023-2024 forecast Financial Reporting and Regulatory Support costs. The Board finds it reasonable to hold AEY's 2023-2024 forecast Financial Reporting and Regulatory Support costs to an amount equal to an average of its previous seven years' actual costs incurred for this cost category. Accordingly, the Board directs AEY to use a forecast for its Financial Reporting and Regulatory Support costs for the years 2023 and 2024 in the amount of \$0.406 million in its compliance filing to this Board Order. Paragraph 83
7. AEY is directed to implement the life-curve parameters in its compliance filing. The proposed and approved life-curve parameters have been summarized by the Board in Appendix 1. Paragraph 101
8. AEY is directed to implement a net salvage of 0 per cent for Account 331.00 – Generation Hydro – Structures and Improvements, in its compliance filing to this Board Order. Paragraph 127
9. AEY is directed to implement a net salvage of -2 per cent for Account 332.00 – Production Hydro – Reservoirs, Dams and Waterways, in its compliance filing to this Board Order. Paragraph 133
10. AEY is directed to implement a net salvage of -2 per cent for Account 333.00 – Production Hydro – Water Wheels, Turbines and Generators, in its compliance filing to this Board Order. Paragraph 139
11. AEY is directed to implement a net salvage of 0 per cent for Account 335.00 – Generation Hydro – Miscellaneous Power Plant Equipment, in its compliance filing to this Board Order. Paragraph 144
12. AEY is directed to implement a net salvage of -1 per cent for Account 341.20 – Generation Diesel – Internal Combustion Structures, in its compliance filing to this Board Order. Paragraph 150
13. AEY is directed to implement a net salvage of -1 per cent for Account 342.20 – Generation Diesel – Internal Combustion Fuel Holders, Producers and Accessories, in its compliance filing to this Board Order. Paragraph 156
14. AEY is directed to implement a net salvage of -5 per cent for 343.20 - Generation Diesel – Internal Combustion Generators in its compliance filing to this Board Order Paragraph 162
15. AEY is directed to implement a net salvage of 0 per cent for Account 345.20 – Generation Diesel – Internal Combustion Accessory in its compliance filing to this Board Order. Paragraph 167
16. AEY is directed to implement a net salvage of -2 per cent for Account 346.20 – Generation Diesel – Internal Combustion Miscellaneous in its compliance filing to this Board Order. Paragraph 173

17. AEY is directed to implement a net salvage of 0 per cent for Account 362.00 – Distribution – Station equipment, in its compliance filing to this Board Order. Paragraph 181
18. AEY is directed to implement a net salvage of -1 per cent for Account 362.10 – Distribution - System Communication and Control, in its compliance filing to this Board Order. Paragraph 187
19. AEY is directed to implement a net salvage of -20 per cent for Account 364.00 – Distribution – Poles, Towers and Fixtures in its compliance filing to this Board Order. Paragraph 193
20. AEY is directed to implement a net salvage of -5 per cent for Account 365.00 – Distribution – Overhead Conductors and Devices in its compliance filing to this Board Order. Paragraph 199
21. AEY is directed to implement a net salvage of -8 per cent for Account 365.10 – Distribution – Overhead Services in its compliance filing to this Board Order. Paragraph 205
22. AEY is directed to implement a net salvage of -10 per cent for Account 367.00 – Distribution – Underground Conductor and Devices in its compliance filing to this Board Order. Paragraph 212
23. AEY is directed to implement a net salvage of -5 per cent for Account 367.10 – Distribution – Underground Services in its compliance filing to this Board Order. Paragraph 217
24. AEY is directed to implement a net salvage of -10 per cent for Account 368.00 – Distribution – Underground Services in its compliance filing to this Board Order. Paragraph 222
25. AEY is directed to implement a net salvage of -2 per cent for Account 370.00 – Distribution – Conventional Meters in its compliance filing to this Board Order. Paragraph 229
26. AEY is directed to implement a net salvage of -10 per cent for Account 373.00 – Distribution – Street Lights in its compliance filing to this Board Order. Paragraph 234
27. AEY is directed to implement a net salvage of +10 per cent for Account 373.10 – Distribution – Sentinel Lights in its compliance filing to this Board Order. Paragraph 239
28. AEY is directed to implement a net salvage of -5 per cent for Account 390.00 – General Plant – Structures and Improvements in its compliance filing to this Board Order. Paragraph 246
29. AEY is directed to implement a net salvage of 0 per cent for Account 390.01 – General Plant – Structures and Improvements Houses in its compliance filing to this Board It Order. Paragraph 252

30. AEY is directed to implement a net salvage of +10 per cent for Account 392.20 – General Plant – Transportation Equipment, Fleet Vehicles Category 2 in its compliance filing to this Board Order. Paragraph 257
31. Accordingly, in its compliance filing, the Board directs AEY to recalculate its amortization of reserve differences calculation to include all relevant adjustments including those cited in the paragraphs above. Given that the amortization of reserve differences calculation is contained primarily in the output of a depreciation study, the Board expects AEY to provide information in its compliance filing, that is consistent with the information found in Attachment 1, Tables 1, 1A, 1B, 2, 2A, 2B and Section 8 (Detailed Depreciation Calculations) of the current Concentric Depreciation Study. All information identified here is to be provided and should support the updated amortization of reserve differences calculation and all other revisions required to AEY’s depreciation expense calculation. Paragraph 261
32. The Board agrees. The absence of an update to the amortization of reserve differences calculation simultaneous with the submission of a technical update creates intergenerational equity issues akin to those that AEY seeks to resolve through reinstating the pre-collection of net salvage costs. This is evident from the significant under and over recoveries for certain accounts, which were held to amortization of reserve differences calculation amounts without update since 1996. For this reason, the Board directs AEY to update its amortization of reserve differences amounts at the time of any technical update to its 2022 and any future depreciation study. Paragraph 264
33. The Board directs AEY to implement its revised accounting practice for contributions in its compliance filing to this Board Order. Paragraph 272
34. In the current BCUC GCOC stage 1, the BCUC determined that FBC’s risk profile has not materially changed since the last GCOC proceeding. In this proceeding, Concentric has stated that AEY’s risk profile has not materially changed since the ROE determinations in Board Order 2017-01. Given the Board was not persuaded by the Concentric evidence in this proceeding and the risk profiles for FBC and AEY have not materially changed, the Board considers that AEY should earn a net lower ROE than FBC. As noted above, in 2017, the Board found that, comparatively, the risk premium for AEY under FBC was 15 basis points. Since the relative risk profiles of FBC and AEY have not materially changed since the last determination on this issue, the Board finds that AEY continues to be less risky than FBC by 15 basis points. FBC was awarded an ROE of 9.65 per cent. Therefore, the Board directs AEY to use an ROE of 9.50 (calculated as 9.65-0.15) per cent and reflect this change in its compliance filing to this Board Order. Paragraph 319
35. Accordingly, to the extent that these expenditures have been capitalized into AEY’s 2023 opening rate base, the Board directs that these costs be removed and remain in CWIP until the entirety of the capital project is in utility service. This direction is based on the AEY testimony provided during the oral hearing (as quoted above), that the Fish Lake Unit 1 Roof Replacement in Business Case 32 is behind schedule and

that the costs are now forecast to be capitalized into rate base in 2024. In the case of Business Case 25, as noted above, Mayo Road Substation project is also currently behind schedule with construction delayed until at least 2024. Paragraph 341

36. Consistent with the Board’s findings with respect to any portion of capital expenditure related to Business Case 32 that were capitalized into AEY’s 2023 opening rate base, the Board finds that expenditures forecast to be capitalized during 2023 (in the amounts noted in the previous paragraph) should be removed and shown as a capital addition in the year 2024. This direction is based on the testimony provided during the oral hearing (and quoted above), that the projects are behind schedule and that the costs are now forecast to be capitalized into rate base in 2024. Paragraph 353
37. Accordingly, for the Mayo Road Substation, while the quantum of forecast capital expenditures appear reasonable, the Board directs that AEY reflect the \$2.554 million capital expenditure in 2024 rather than in 2023. Further, the Board denies AEY the capitalization of any portion of the Mayo Road Substation within the test years and AEY is directed to remove the associated forecast capital addition for this project from the 2023-2024 test period. At the time of its next GRA, AEY will be able to reflect the Mayo Road Substation capital addition in its 2025 opening rate base, assuming it has been completed by then. Paragraph 364
38. For the Whistle Bend – Leota Substation, the Board similarly finds that the quantum of forecast capital expenditures appear reasonable. However, given that construction for this project is not underway, the Board directs that AEY reflect the \$0.154 million capital expenditure in 2024 rather than in 2023. The Board also denies AEY the capitalization of any Whistle Bend – Leota Substation within the test years and AEY is directed to remove the associated forecast capital addition for this project from the 2023-2024 test period. At the time of its next GRA, AEY will be able to reflect the Whistle Bend – Leota Substation capital addition in its 2025 opening rate base, assuming it has been completed by then. Paragraph 365
39. In any event, the Board finds that AEY has not provided sufficient specifics with respect to the nature and timing of its forecast 2024 capital expenditures, particularly in light of the Mayo Road and Whistle Bend Substations being delayed. Given the delays it is experiencing on the Mayo Road and Whistle Bend – Leota substations and the fact that AEY has indicated that these will take priority over the DWCI substation, the Board has doubts about AEY’s ability to commence the construction of the DWCI substation during the 2024 test period. The Board therefore directs AEY to remove its 2024 forecast capital expenditures of \$0.792 million in its compliance filing to this Board Order. Paragraph 379
40. During the oral hearing AEY explained there had been no success with the AMI project’s single installed meter and its ability to interface with AEY’s new billing system. This results in uncertainty as to how this critical function will be achieved and at what cost. Given the importance of this aspect of the AMI project, the Board

directs AEY to provide an update on the project at its's next GRA, specifically addressing these issues, how they have been resolved, and the cost of resolving them. Paragraph 388

41. The Board approves, for 2023, an amount equal to AEY's actual 2023 capital expenditures of \$0.006 million with the balance of forecast costs (being \$0.430 million of the total \$0.436 million 2023-2024 forecast capital expenditures) to be recorded in the year 2024. However, the Board declines to approve the capitalization of any amount of these costs into AEY's 2023 or 2024 rate base at this time. Accordingly, to the extent that AEY has forecast any capital additions for 2023-2024 for the AMI project, the Board directs that these costs be removed. When AEY is better able to articulate the costs and benefits of this project over the longer-term phased-in period including the AMI meter's ability to interface with AEY's new billing system, the Board will re-examine the information provided by AEY to determine the prudence of the 2023-2024 capital expenditures and whether further capital expenditures have been justified and are thus warranted. Paragraph 389
42. Based on AEY's historical spend on street and sentinel lighting and AEY's spend-to-date (August 2023), the Board is concerned with AEY's ability to complete all street and sentinel lights as forecast before the fiscal year-end. For the compliance filing to this Board Order, AEY is directed to use the actual 2023 capitalized into rate base amounts for street and sentinel lights, for the compliance filing to this Board Order. The Board accepts the 2024 forecast amounts for street and sentinel lighting as reasonable. Paragraph 394
43. As noted above, AEY has identified costs for the first two years of the five-year roadmap, and stated there would be operating costs involved but currently cannot quantify those costs. Further, AEY has not submitted the full capital costs for the entire project or provided estimates of annual operating costs. All benefits have been identified as qualitative and mid to long term in nature. AEY has been unable to identify any specific revenue requirement savings from this project. AEY is asking for approval to commence a project with unknown final costs and uncertain benefits. In other words, AEY is asking rate payers to pay for a project with unspecified total costs, unspecified financial benefits, and only possible long-term intangible benefits. This represents a risk that ratepayers should not be asked to take. For these reasons, the Board cannot approve this project until such time as the costs and benefits of this project are more quantifiable and specific to AEY. The Board directs that all costs for the AS project be removed from the revenue requirement for AEY in its compliance filing to this Board Order. Paragraph 406
44. Based on AEY's historical spend on these GPE categories and noting lagging supply issues as a remnant of the COVID-19 pandemic, the Board is concerned with the increases in the capital spend for these two items and AEY's ability to acquire all those assets before the fiscal year-end. In its compliance filing to this Board Order, AEY is directed to use actual 2023 capitalized amounts for tools and transportation

equipment. The Board accepts the 2024 forecast amounts for these two cost categories as reasonable. Paragraph 413

45. The Board notes that AEY continues to use the flow-through method in calculating income tax expense. The Board accepts this method of calculating income taxes. However, the Board notes AEY will have to recalculate its income tax expense in the compliance filing to this Board Order to reflect the changes AEY must undertake to comply with the directions in other parts of this decision. AEY is directed to undertake that recalculation of income taxes in its compliance filing to this Board Order. Paragraph 416