ATCO Electric Transmission (AET)
SUMMARY OF REVENUE REQUIREMENT
FOR THE YEAR ENDED DECEMBER 31, 2019
($Millions)

Line No.	Description	Cross-Reference	2019 Actual	2019 Approved*	2018 Actual	Var. Actual to Approved	Var. %	Var. Actual to Prior Year	Var. %	Working Paper Reference
1	Return on Rate Base	Sch 2.0-T	320.0	310.2	299.8	9.8	3.2%	20.2	6.7%	
2	Fuel		5.5	7.1	7.5	(1.6)	-22.4%	(2.0)	-27.0%	Note 1
3	Operating and Maintenance	Sch 3.0-T	160.2	150.5	174.2	9.8	6.5%	(14.0)	-8.0%	
4	Depreciation and Amortization	Sch 4.0-T	188.5	194.5	193.0	(6.0)	-3.1%	(4.6)	-2.4%	
5	Utility Income Tax	Sch 5.0-T	38.5	39.9	25.1	(1.4)	-3.6%	13.4	53.4%	
6	Subtotal		712.7	702.1	699.6	10.6	1.5%	13.0	1.9%	
7										
8	Revenue Offsets		(26.8)	(10.3)	(29.3)	(16.5)	161.2%	2.5	-8.5%	Note 2
9										
10	**Total Transmission Revenue Requirement**	Sch 10	685.9	691.8	670.3	(6.0)	-0.9%	15.5	2.3%	
11										
12										
13	<u>Detailed Revenue Requirement</u>									
14	Transmission Tariff Revenue		691.9	691.8	673.8	0.1	0.0%	18.07	2.7%	
15	Deferral Account		(6.0)	-	(3.5)	(6.0)	100.0%	(2.5)	73.0%	Note 3
16	**Total Transmission Revenue Requirement**	Line 10	685.9	691.8	670.3	(6.0)	-0.9%	15.5	2.3%	
17										
18	**Variance Explanations**									

Note 1 The 2019 Actuals are lower than 2019 Approved by ($1.6) mainly due to lower natural gas volume which is the result of earlier than planned completion of the Jasper Interconnection Project.

Note 2 The 2019 Actuals are higher than 2019 Approved by ($16.5) mainly due to higher revenues for services provided for the WFMAC project (Alberta PowerLine) and ATCO Power related to non-labour flowthrough costs of ($13.5) which are not forecast, as well as increased labour and fringe requirements.

Note 3 The 2019 Actuals are lower than 2019 approved by ($6.0) due to the annual true up of deferral accounts. The refund of revenue requirement is mainly due to the taxes other than income (property taxes) deferral account ($5.4), the inclusion of IT Common Matter disallowance of ($1.2) for 2019 , the right of way deferral ($0.5), long term debt rate deferral ($0.3), and capital repairs ($0.3). This variance is partially offset by collections related to the direct assign capital deferral ($0.5) and the deducting deferral ($1.2).

* - Per AET's 2018-2019 GTA Compliance Filing, Proceeding ID 24805, Exhibit X0005.01

ATCO Electric Transmission (AET)

SUMMARY OF RETURN ON RATE BASE

FOR THE YEAR ENDED DECEMBER 31, 2019

($Millions)

2019 Actuals

Line No.	Description	Cross-Reference	Mid-Year Capital	Ratio	Prorated Rate Base	Cost Rate %	Return $	Var. Actual to Approved	Var. %	Working Paper Reference
1	**Mid Year Rate Base (Farms, Irrigation Transmission)**				28.2	5.73%	1.5	(0.4)	-21.7%	
2	**Mid Year Rate Base**									
3	Long-Term Debt	Sch 2.2-T	3,294.0	61.29%	3,136.0	4.62%	145.0	0.2	0.2%	
4	Preferred Shares	Sch 2.2-T	91.7	1.71%	87.3	3.96%	3.5	0.0	0.2%	
5	Common Equity	Sch 2.2-T	1,988.4	37.00%	1,893.1	8.98%	170.0	10.0	6.2%	**Note 1**
6	**Mid-Year Net Rate Base**	Sch 1.0-T	5,374.0	100.00%	5,116.4	6.25%	320.0	9.8		
7	Contribution for Extensions				524.0					
8	No Cost Capital	Sch 2.1-T			209.6					
9	**Mid Year Rate Base**				5,849.9					

2019 Approved*

Line No.	Description	Cross Reference	Mid Year Capital	Deemed Structure	Prorated Rate Base	Cost Rate %	Return $
10	**Mid Year Rate Base (Farms, Irrigation Transmission)**				36.9	5.3%	2.0
11	**Mid Year Rate Base**						
12	Long-Term Debt	Sch 2.2-T	3,282.5	61.29%	3,118.8	4.6%	144.8
13	Preferred Shares	Sch 2.2-T	91.7	1.71%	87.1	4.0%	3.4
14	Common Equity	Sch 2.2-T	1,981.6	37.00%	1,882.8	8.5%	160.0
15	**Mid-Year Net Rate Base**	Sch 1.0-T	5,355.7	100.00%	5,088.7	6.1%	310.2
16	Contribution for Extensions				550.3		
17	No Cost Capital	Sch 2.1-T			201.8		
18	**Mid Year Rate Base**				5,840.7		
19							
20	**Return Variance**						

Note 1 Please refer to Schedule 1.0-T for variances between actual and approved which impact Return on Common Equity.

* Per AET's 2018-2019 GTA Compliance Filing, Proceeding ID 24805, Exhibit X0005.01

ATCO Electric Transmission (AET)
SUMMARY OF MID-YEAR RATE BASE
FOR THE YEAR ENDED DECEMBER 31, 2019
($Millions)

Line No.	Description	Cross-Reference	2019 Actual	2019 Approved*	2018 Actual	Var. Actual to Approved	Var. %	Var. Actual to Prior Year	Var. %	Working Paper Reference
1	Gross Utility Plant in Service									
2	Opening Balance	Sch 4.1-T	7,342.5	7,357.4	7,109.9	(14.9)	-0.2%	232.6	3.3%	
3	Closing Balance	Sch 4.1-T	7,579.0	7,611.9	7,351.5	(32.9)	-0.4%	227.5	3.1%	
4	**Mid-Year Gross Utility Plant in Service**		7,460.8	7,484.7	7,230.7	(23.9)	-0.3%	230.1	3.2%	
5										
6	Accumulated Depreciation - Utility									
7	Opening Balance	Sch 4.1-T	1,581.4	1,587.0	1,400.1	(5.6)	-0.4%	181.3	12.9%	
8	Closing Balance	Sch 4.1-T	1,728.8	1,790.1	1,583.5	(61.3)	-3.4%	145.3	9.2%	
9	**Mid-Year Accumulated Depreciation - Utility**		1,655.1	1,688.6	1,491.8	(33.5)	-2.0%	163.3	10.9%	
10										
11	Contributions in Aid of Construction									
12	Opening Balance		540.6	546.9	540.0	(6.3)	-1.1%	0.6	0.1%	
13	Closing Balance		529.7	571.1	540.6	(41.4)	-7.2%	(10.9)	-2.0%	
14	**Mid-Year Utility Contributions in Aid of Construction**		535.1	559.0	540.3	(23.8)	-4.3%	(5.2)	-1.0%	
15										
16	Amortization of Contributions									
17	Opening Balance		62.4	64.2	54.2	(1.8)	-2.9%	8.2	15.2%	
18	Closing Balance		58.0	74.4	62.4	(16.4)	-22.0%	(4.4)	-7.0%	
19	**Mid-Year Utility Amortization of Contributions**		60.2	69.3	58.3	(9.1)	-13.1%	1.9	3.3%	
20										
21										
22	**Mid-Year Net Utility Plant in Service**		5,330.8	5,306.5	5,256.9	24.3	0.5%	73.9	1.4%	
23										
24	Necessary Working Capital		44.2	44.6	42.6	(0.4)	-0.9%	1.6	3.7%	
25										
26	No Cost Capital		(209.6)	(201.8)	(175.2)	(7.8)	3.9%	(34.3)	19.6%	
27										
28	**Mid-Year Net Rate Base**		5,165.4	5,149.3	5,124.3	16.1	0.3%	41.1	0.8%	
29										
30	Mid-Year Contributions CWIP		(49.0)	(60.7)	(40.6)					
31										
32	**Total Mid-Year Rate Base and CWIP**	Sch. 2.0-T	**5,116.4**	**5,088.7**	**5,083.7**					

***** - Per AET's 2018-2019 GTA Compliance Filing, Proceeding ID 24805, Exhibit X0005.01

ATCO Electric Transmission (AET)
SUMMARY OF MID-YEAR CAPITAL STRUCTURE
FOR THE YEAR ENDED DECEMBER 31, 2019
($Millions)

Line No.	Description	Cross-Reference	Current Year-End	Previous Year-End	Actual Mid-Year Capital	2019 Approved* Mid-Year Capital	Var. Actual to Approved	Var. %	Working Paper Reference
1	Long-Term Debt	Sch 2.3	3,247.7	3,340.2	3,294.0	3,282.5	11.5	0.4%	
2	Preferred Shares	Sch 2.4	91.7	91.7	91.7	91.7	0.0	0.0%	
3	Common Equity		1,878.4	2,098.4	1,988.4	1,981.6	6.8	0.3%	
4									
5	**Total Mid-Year Invested Capital**		**5,217.8**	**5,530.2**	**5,374.0**	**5,355.7**	**18.3**	**0.3%**	

* - Per AET's 2018-2019 GTA Compliance Filing, Proceeding ID 24805, Exhibit X0005.01

ATCO Electric Transmission (AET)
SCHEDULE OF DEBT CAPITAL EMPLOYED
FOR THE YEAR ENDED DECEMBER 31, 2019
($Millions)

2019 Actual

Line No.	Cross-Reference	Description	Series	Issue Date	Maturity Date	Coupon Rate	Principal Amount	Underwriting Discount & Expense	Total Amount	Effective Cost Rate %	Principal Outstanding at Year-End	Carrying Cost	Average Embedded Cost Rate
1		LT Adv. -Parent											
2			Y	1990-11-30	2020	11.8%	22.4	0.2	22.2	11.8%	22.4	2.6	
3			Z	1991-12-18	2022	9.9%	29.3	0.4	29.0	10.0%	29.3	2.9	
4			AA	1992-12-08	2023	9.4%	13.8	0.1	13.7	9.4%	13.8	1.3	
5			2004	2004-11-18	2034	5.9%	71.1	0.4	70.6	5.9%	70.8	4.2	
6			2005	2005-11-30	2035	5.2%	56.3	0.4	56.0	5.2%	56.1	2.9	
7			2006	2006-11-20	2021	4.8%	59.3	0.3	58.9	4.8%	59.2	2.9	
8			2006	2006-11-20	2036	5.0%	59.3	0.4	58.9	5.1%	59.1	3.0	
9			2007	2007-11-01	2037	5.6%	79.2	0.5	78.7	5.6%	78.9	4.4	
10			2008	2008-05-26	2028	5.6%	29.3	0.2	29.1	5.6%	29.3	1.6	
11			2008	2008-05-26	2038	5.6%	44.0	0.3	43.7	5.6%	43.8	2.5	
12			2009	2009-03-06	2024	6.2%	68.1	0.4	67.6	6.3%	67.9	4.3	
13			2009	2009-03-07	2039	6.5%	85.7	0.6	85.1	6.6%	85.3	5.6	
14			2010	2010-11-10	2050	4.9%	73.3	0.5	72.8	5.0%	72.9	3.6	
15			2011	2011-10-24	2041	4.5%	192.8	1.2	191.6	4.6%	191.8	8.8	
16			2011	2011-10-24	2061	4.6%	77.1	0.5	76.6	4.6%	76.7	3.5	
17			2012	2012-09-10	2042	3.8%	317.3	2.0	315.3	3.8%	315.6	12.1	
18			2012	2012-09-10	2062	3.8%	126.8	0.8	126.0	3.9%	126.0	4.9	
19			2012	2012-11-14	2052	3.9%	161.2	1.0	160.2	3.9%	160.2	6.2	
20			2013	2013-09-09	2043	4.7%	241.0	1.6	239.4	4.8%	239.6	11.4	
21			2013	2013-09-18	2063	4.9%	75.0	0.6	74.4	4.9%	74.4	3.6	
22			2013	2013-11-07	2053	4.6%	225.0	1.4	223.6	4.6%	223.7	10.3	
23			2014	2014-09-05	2044	4.1%	555.0	3.5	551.5	4.1%	551.9	22.7	
24			2014	2014-10-17	2054	4.1%	180.0	1.2	178.8	4.1%	178.9	7.4	
25			2015	2015-07-27	2045	4.0%	110.0	0.8	109.2	4.0%	109.3	4.4	
26			2015	2015-10-29	2055	4.2%	185.0	1.3	183.7	4.2%	183.8	7.8	
27			2018	2018-11-21	2048	4.0%	90.0	0.6	89.4	4.0%	89.4	3.6	
28			2019	2019-09-05	2049	3.0%	72.0	0.5	71.5	3.0%	71.5	2.1	
29											3,281.7	150.7	4.6%
30													
31		Short-term Debt / (Investment)				2.3%	(34.0)		(34.0)	2.3%	(34.0)	(0.8)	
32													
33		2019 Ending Balance									3,247.7	150.0	4.6%
34		2019 Opening Balance									3,340.2	154.6	4.6%
35		**Mid-Year Balance**									**3,294.0**	**152.3**	**4.6%**
36													
37													

ATCO Electric Transmission (AET)
SCHEDULE OF DEBT CAPITAL EMPLOYED
FOR THE YEAR ENDED DECEMBER 31, 2019
($Millions)

2019 Approved

Line No.	Cross-Reference	Description	Series	Issue Date	Maturity Date	Coupon Rate	Principal Amount	Underwriting Discount & Expense	Total Amount	Effective Cost Rate %	Principal Outstanding at Year-End	Carrying Cost	Average Embedded Cost Rate
1		LT Adv. - Parent											
2			Y	1990-11-30	2020	11.8%	22.4	0.2	22.2	11.8%	22.4	2.6	
3			Z	1991-12-18	2022	9.9%	29.3	0.4	28.9	10.0%	29.3	2.9	
4			AA	1992-12-08	2023	9.4%	13.8	0.1	13.6	9.4%	13.8	1.3	
5			2004	2004-11-18	2034	5.9%	71.0	0.4	70.5	5.9%	70.8	4.2	
6			2005	2005-11-30	2035	5.2%	56.3	0.4	55.9	5.2%	56.1	2.9	
7			2006	2006-11-20	2021	4.8%	59.2	0.3	58.9	4.8%	59.1	2.9	
8			2006	2006-11-20	2036	5.0%	59.2	0.4	58.8	5.1%	59.0	3.0	
9			2007	2007-11-01	2037	5.6%	79.1	0.5	78.6	5.6%	78.8	4.4	
10			2008	2008-05-26	2028	5.6%	29.3	0.2	29.1	5.6%	29.2	1.6	
11			2008	2008-05-26	2038	5.6%	44.0	0.3	43.7	5.6%	43.8	2.5	
12			2009	2009-03-06	2024	6.2%	68.0	0.4	67.5	6.3%	67.9	4.3	
13			2009	2009-03-07	2039	6.5%	85.6	0.6	85.0	6.6%	85.2	5.6	
14			2010	2010-11-10	2050	4.9%	73.3	0.5	72.7	5.0%	72.8	3.6	
15			2011	2011-10-24	2041	4.5%	192.6	1.2	191.4	4.6%	191.6	8.8	
16			2011	2011-10-24	2061	4.6%	77.0	0.5	76.5	4.6%	76.6	3.5	
17			2012	2012-09-10	2042	3.8%	319.9	2.0	317.9	3.8%	318.2	12.2	
18			2012	2012-09-10	2062	3.8%	127.8	0.8	127.0	3.9%	127.0	4.9	
19			2012	2012-11-14	2052	3.9%	162.4	1.0	161.4	3.9%	161.5	6.3	
20			2013	2013-09-09	2043	4.7%	241.0	1.5	239.5	4.8%	239.6	11.4	
21			2013	2013-09-18	2063	4.9%	75.0	0.6	74.4	4.9%	74.4	3.7	
22			2013	2013-11-07	2053	4.6%	225.0	1.4	223.6	4.6%	223.7	10.3	
23			2014	2014-09-05	2044	4.1%	555.0	3.3	551.7	4.1%	551.9	22.8	
24			2014	2014-10-17	2054	4.1%	180.0	1.2	178.8	4.1%	178.9	7.4	
25			2015	2015-07-27	2045	4.0%	110.0	0.7	109.3	4.0%	109.3	4.4	
26			2015	2015-10-29	2055	4.2%	185.0	1.2	183.8	4.3%	183.8	7.8	
27			2018	2018-11-21	2045	4.0%	90.0	0.6	89.4	4.0%	89.4	3.6	
28			2019	2019-06-30	2049	4.0%	60.0	0.4	59.6	4.0%	59.6	2.4	
29											3,273.7	151.3	4.6%
30													
31		Short-term Debt				0.5%	2.0		2.0	0.5%	2.0	0.0	
32		Notes Payable											
33													
34		2019 Ending Balance									3,275.7	151.3	4.6%
35		2019 Opening Balance									3,289.2	153.4	4.7%
36		**Mid-Year Balance**									**3,282.5**	**152.4**	**4.6%**
37													
38	**Note 1**	In accordance with Commission Direction 43-45 in Decision 22742-D01-2019, the 2019 actual debt rate cost is 3.95%											

* - Per AET's 2018-2019 GTA Compliance Filing, Proceeding ID 24805, Exhibit X0005.01

ATCO Electric Transmission (AET)
SCHEDULE OF PREFERRED SHARE CAPITAL EMPLOYED
FOR THE YEAR ENDED DECEMBER 31, 2019
($Millions)

2019 Actual

Line No.	Cross-Reference	Series	Issue Date	Dividend Rate	Stated Value of Issue	Underwriting Discount & Expense	Net Proceeds Outstanding	Carrying Cost of Issue	Average Embedded Cost Rate
1		V	2007	4.60%	27.9	-	27.9	1.3	4.60%
2		1	2007	4.60%	38.9	-	38.9	1.8	4.60%
3		4	2010	2.24%	24.9	-	24.9	0.6	2.24%
4									
5		Current Year-End Balance			91.7	-	91.7	3.6	3.96%
6		Prior Year-End Balance			91.7	-	91.7	3.6	3.96%
7		Total			183.3		183.3	7.3	3.96%
8		Mid-Year Balance			91.7		91.7	3.6	3.96%

2019 Approved*

Line No.	Cross-Reference	Series	Issue Date	Dividend Rate	Stated Value of Issue	Underwriting Discount & Expense	Net Proceeds Outstanding	Carrying Cost of Issue	Average Embedded Cost Rate
9		V	2007	4.60%	27.9	-	27.9	1.3	4.60%
10		1	2007	4.60%	38.9	-	38.9	1.8	4.60%
11		4	2010	2.24%	24.9	-	24.9	0.6	2.24%
12									
13		Current Year-End Balance			91.7	-	91.7	3.6	3.96%
14		Prior Year-End Balance			91.7	-	91.7	3.6	3.96%
15		Total			183.3		183.3	7.3	3.96%
16		Mid-Year Balance			91.7		91.7	3.6	3.96%

* - Per AET's 2018-2019 GTA Compliance Filing, Proceeding ID 24805, Exhibit X0005.01

ATCO Electric Transmission (AET)
SUMMARY OF OPERATING AND MAINTENANCE EXPENSE
FOR THE YEAR ENDED DECEMBER 31, 2019
($Millions)

Line No.	Acct No.	Description	Cross-Reference	2019 Actual	2019 Approved*	2018 Actual	Var. Actual to Approved	Var. %	Var. Actual to Prior Year	Var. %	Working Paper Reference
1		**Direct Operation & Maintenance Expense**									
2	560	Supervision and Engineering		2.6	3.5	2.9	(0.9)	-25.7%	(0.3)	-11.0%	
3	561	Control Centre Operations		4.3	4.3	3.7	(0.0)	-0.4%	0.5	14.1%	
4	562	Station Equipment Expenses		7.4	9.0	8.5	(1.5)	-17.3%	(1.1)	-13.3%	**Note 1**
5	563/569	Overhead Lines Expenses & Operation Maintenance		2.4	2.6	2.5	(0.2)	-7.9%	(0.1)	-4.6%	
6	566	Miscellaneous Transmission Expense		33.0	15.1	39.6	17.9	118.0%	(6.6)	-16.6%	**Note 2**
7	567	Right of Way Payments		6.6	7.1	6.7	(0.5)	-7.6%	(0.2)	-2.6%	
8	571.1	Vegetation Management		10.1	10.0	10.9	0.0	0.4%	(0.8)	-7.7%	
9	575	IT Support		3.6	2.8	3.0	0.8	27.4%	0.7	22.7%	**Note 3**
10				70.0	54.5	77.9	15.5	28.4%	(8.0)	-10.2%	
11											
12		Isolated Generation Operation & Maintenance		2.9	5.3	4.5	(2.4)	-44.6%	(1.6)	-34.7%	**Note 4**
13				2.9	5.3	4.5	(2.4)	-44.6%	(1.6)	-34.7%	
14											
15		**Total Operation and Maintenance Costs**		**72.9**	**59.8**	**82.4**	**13.1**	**21.9%**	**(9.5)**	**-11.6%**	
16											
17		Allocated Administrative and General	Sch 3.1-T	42.0	39.7	46.0	2.3	5.9%	(4.0)	-8.8%	
18		Taxes Other Than Income		44.7	50.2	45.0	(5.4)	-10.9%	(0.3)	-0.6%	**Note 5**
19				86.7	89.9	91.0	(3.1)	-3.5%	(4.3)	-4.7%	
20											
21				159.6	149.6	173.5	10.0	6.7%	(13.8)	-8.0%	
22											
23		Farms, Irrigation Transmission Operating Costs		0.6	0.8	0.8	(0.2)	-27.1%	(0.2)	-20.7%	
24											
25		**Total Transmission O&M Costs**	Sch 1.0-T	**160.2**	**150.5**	**174.2**	**9.8**	**6.5%**	**(14.0)**	**-8.0%**	

Variance Explanations

Note 1 2019 Actuals are lower than Approved by ($1.5) mainly due to lower metering services provided to AED ($0.8), lower vehicle usage ($0.6) and contractor usage ($0.4). The variance is partially offset by higher radio license fees ($0.3).

Note 2 2019 Actuals are higher than Approved by $17.9 mainly due to higher Affiliate Cost of Goods Sold for Affiliate Work ($12.9) and Alberta PowerLine ($3.4), bad debt and write-off of cancelled projects ($2.9), and lower vehicle depreciation as the vehicle usage costs no longer include vehicle depreciation credit amounts ($1.3). Historically, the vehicle depreciation credits offset amounts related to depreciation that were already recorded in depreciation expense. The new process excludes depreciation amounts from O&M entirely. The change in process has no impact on overall revenue requirement. This is partially offset by reduced rent costs ($2.8). The Affiliate Cost of Goods Sold are offset by Affiliate Revenues and will have no impact on revenue requirement.

Note 3 2019 Actuals are higher than Approved by ($0.8) mainly due to higher charges for miscellaneous software.

Note 4 2019 Actuals are lower than Approved by ($2.4) mainly due to reduced operations and maintenance labour as a result of the completion of the Jasper Palisades interconnection ($1.5), lower materials ($0.4), and lower contractor services ($0.3).

Note 5 2019 Actual are lower than Approved by ($5.4) mainly due to a 12% lower weighted average mill rate than approved for. This account is subject to deferral treatment and will be trued up in a future deferral account application.

***** - Per AET's 2018-2019 GTA Compliance Filing, Proceeding ID 24805, Exhibit X0005.01

ATCO Electric Transmission (AET)
SUMMARY OF OPERATING AND MAINTENANCE EXPENSE (CORPORATE)
FOR THE YEAR ENDED DECEMBER 31, 2019
($Millions)

Line No.	Acct. No.	Description	Cross-Reference	2019 Actual	2019 Approved*	2018 Actual	Var. Actual to Approved	Var. %	Var. Actual to Prior Year	Var. %	Working Paper Reference
1		**Direct Operation & Maintenance Expense**									
2	920	General Administration		13.0	11.5	15.1	1.5	13.2%	(2.1)	-13.7%	**Note 1**
3	921	Office Supplies and Expenses		5.5	5.5	7.4	(0.1)	-1.4%	(1.9)	-25.7%	
4	923	Outside Services Employed		1.0	1.5	1.6	(0.5)	-33.2%	(0.6)	-37.4%	
5	924	Insurance Premiums		3.2	3.7	3.3	(0.5)	-12.4%	(0.1)	-3.7%	
6	925	Injuries and Damages		(0.0)	(0.0)	(0.0)	-	0.0%	-	0.0%	
7	928	Board Expenses		1.9	1.9	1.9	0.0	0.7%	0.0	0.7%	
8	930.2	Miscellaneous General Expenses		16.1	14.0	17.4	2.1	14.9%	(1.2)	-7.2%	**Note 2**
9	931.1	Head Office Rent		1.6	1.5	1.7	0.0	1.6%	(0.1)	-8.2%	
10	934	IT G&A Expense	`	4.6	3.8	3.5	0.8	21.9%	1.1	30.9%	**Note 3**
11	941	Board Expenses Disallowed		1.4	1.6	1.1	(0.2)	-13.1%	0.3	23.2%	
12	935.2	Maintenance Company Owned Houses		0.1	0.2	0.1	(0.2)	-73.6%	(0.1)	-55.5%	
13				48.3	45.2	53.0	3.1	6.8%	(4.8)	-9.0%	
14		**Non-utility Items**									
15		Donations		(0.4)	(0.6)	(0.4)	0.2	-34.6%	0.0	-7.6%	
16		Disallowed Head Office Costs		(0.9)	-	(0.6)	(0.9)	-100.0%	(0.3)	57.9%	
17		License Fees		(3.2)	(3.2)	(4.6)	(0.0)	0.4%	1.4	-30.1%	
18		Disallowed Aircraft		(0.1)	-	(0.2)	(0.1)	-100.0%	0.1	-59.2%	
19		Legal Cost in Excess of Board Scale		(1.4)	(1.6)	(1.1)	0.2	-13.1%	(0.3)	23.2%	
20		Pension - COLA		(0.3)	(0.1)	(0.1)	(0.2)	200.0%	(0.2)	249.0%	
21				(6.2)	(5.5)	(7.0)	(0.7)	13.3%	0.7	-10.6%	
22											
23		**Total Administration and General**	Sch 3.0-T	**42.0**	**39.7**	**46.0**	**2.3**	5.9%	**(4.0)**	-8.8%	
24											
25		Total Labour and Fringe		11.1	12.1	9.1	(1.1)	-8.7%	1.9	21.2%	
26		Total Other		30.9	27.5	36.9	3.4	12.3%	(6.0)	-16.2%	
27		Total Administration and General		42.0	39.7	46.0	2.3	5.9%	(4.0)	-8.8%	

Variance Explanations

Note 1 2019 Actuals are higher than Approved by $1.5 mainly due to timing of severance that was forecast to occur in 2018.

Note 2 2019 Actuals are higher than Approved by $2.1 mainly due to higher Head Office costs ($2.6) and higher Affiliate Cost of Goods Sold ($0.3), partially offset by lower Affiliate Cost of Goods Sold for Alberta PowerLine ($1.1). The Affiliate Cost of Goods Sold are offset by Affiliate Revenues and have no impact on revenue requirement.

Note 3 2019 Actuals are higher than Approved by $1.0 mainly due to unforecasted charges for Legacy System operations and Oracle Cloud subscriptions ($0.9).

***** - Per AET's 2018-2019 GTA Compliance Filing, Proceeding ID 24805, Exhibit X0005.01

ATCO Electric Transmission (AET)
SUMMARY OF DEPRECIATION EXPENSE
FOR THE YEAR ENDED DECEMBER 31, 2019
($Millions)

Line No.	Description	Cross-Reference	2019 Actual	2019 Approved*	2018 Actual	Var. Actual to Approved	Var. %	Var. Actual to Prior Year	Var. %	Working Paper Reference
1	Transmission		174.9	179.6	178.4	(4.6)	-2.6%	(3.5)	-1.9%	
2	Amortization of Differences		4.8	5.3	4.8	(0.5)	-9.9%	0.1	1.2%	
3	**Subtotal**		179.7	184.9	183.2	(5.1)	-2.8%	(3.4)	-1.9%	
4										
5	**Direct General PP&E**									
6	Structures & Improvements		2.8	2.9	2.8	(0.1)	-2.8%	0.0	0.8%	
7	Office Furniture and Equipment		0.8	0.8	0.8	0.0	1.5%	0.0	2.8%	
8	Computer Equipment		0.1	0.1	0.1	(0.0)	-17.0%	(0.0)	-33.8%	
9	Transportation Equipment		3.3	3.8	3.7	(0.4)	-11.7%	(0.3)	-9.3%	
10	Tools & Instruments		3.3	3.3	3.2	0.0	0.3%	0.0	1.0%	
11	Housing		-	-	0.0	-	0.0%	(0.0)	0.0%	
12	Leasehold Improvements		1.6	1.7	1.9	(0.1)	-3.9%	(0.3)	-14.3%	
13	Software		8.1	9.4	7.1	(1.3)	-13.7%	1.0	14.1%	
14	Amortization of Differences		0.6	0.0	0.6	0.6	7196.6%	0.0	0.9%	
15	**Subtotal**		20.6	21.9	20.2	(1.3)	-5.9%	0.4	2.1%	
16										
17										
18	**Transmission Gross Provision**		200.3	206.8	203.3	(6.4)	-3.1%	(3.0)	-1.5%	
19										
20	Farms, Irrigation Transmission		1.3	1.6	1.7	(0.3)	-18.1%	(0.4)	-22.5%	
21										
22	**Total Transmission Gross Depreciation Expense**		201.7	208.4	205.0	(6.7)	-3.2%	(3.4)	-1.6%	
23										
24	Depreciation Gross Provision - Life		161.8	172.0	164.7	(10.2)	-5.9%	(2.9)	-1.8%	
25	Depreciation Gross Provision - Net Salvage		39.9	36.4	40.3	3.5	9.5%	(0.4)	-1.1%	
26			201.7	208.4	205.0	(6.7)	-3.2%	(3.4)	-1.6%	
27										
28	Gross Depreciation Expense		201.7	208.4	205.0	(6.7)	-3.2%	(3.4)	-1.6%	
29	Vehicle Depreciation Capitalized		(2.7)	(3.6)	(1.9)	0.9	-25.6%	(0.8)	42.2%	
30	Amortization of Contributions		(10.6)	(10.4)	(10.1)	(0.2)	1.6%	(0.4)	4.1%	
31	**Total Depreciation and Amortization Expense**		188.5	194.5	193.0	(6.0)	-3.1%	(4.6)	-2.4%	
32										
33										
34	**Total Depreciation and Amortization Expense (including Refund of Pension contributions capitalized)**	Sch 1.0-T	188.5	194.5	193.0	(6.0)	-3.1%	(4.6)	-2.4%	**Note 1**
35										
36	**Variance explanation**									
37										

38 **Note 1** The 2019 depreciation expense is lower than 2019 Approved mainly due to lower actual opening depreciable base, lower depreciation expense associated with Direct
39 Assigned capital additions which is subject to deferral treatment, and an update to the composite depreciation rate on AFUDC differential assets for prior years to
40 better align with the depreciation rate included in the revenue requirement.

***** - Per AET's 2018-2019 GTA Compliance Filing, Proceeding ID 24805, Exhibit X0005.01

ATCO Electric Transmission (AET)
CAPITAL ASSETS CONTINUITY SCHEDULE
FOR THE YEAR ENDED DECEMBER 31, 2019
($Millions)

CAPITAL ASSETS

Line No.	Property Group	Cross-Reference	Balance at 12/31/2018	Prior years' Disallowances	Prior Year Disallowances & Opening Balance Adjustments	2019 Additions	2019 Retirements	2019 Transfers	2019 Adjustments	2019 Pension Disallowance	Balance at 12/31/2019
1	Transmission		7,043.1	(7.4)	7,035.7	253.8	(27.5)	-	9.8	(0.2)	7,271.6
2											
3	**Direct General PP&E**										
4	Land		4.9	-	4.9	(0.1)	(0.0)	-	-	-	4.8
5	Structures and Improvements		119.5	-	119.5	1.5	(0.2)	-	-	-	120.8
6	Office Furniture and Equipment		12.7	-	12.7	0.1	(0.0)	-	-	-	12.7
7	Computer Equipment		0.3	-	0.3	0.6	(0.0)	-	-	-	0.8
8	Transportation Equipment		53.9	-	53.9	0.5	(1.2)	-	-	-	53.1
9	Tools and Instruments		31.3	-	31.3	3.8	(0.5)	-	-	-	34.5
10	Leasehold Improvements		14.0	-	14.0	-	(2.5)	-	-	-	11.5
11	Software		71.9	(1.6)	70.4	5.7	(7.0)	-	-	-	69.1
12	**Subtotal**		308.4	(1.6)	306.8	12.0	(11.4)	-	-	-	307.4
13											
14	**Subtotal - Utility Plant in Service**	Sch 2.1-T	7,351.5	(9.0)	7,342.5	265.8	(39.0)	-	9.8	(0.2)	7,579.0
15											
16	Capital Work in Progress (CWIP)		189.6	-	189.6	(82.9)	-	-	-	-	106.7
17											
18	**Total Transmission**		7,541.1	(9.0)	7,532.1	183.0	(39.0)	-	9.8	(0.2)	7,685.7
19											
20											

ACCUMULATED DEPRECIATION

Line No.	Property Group	Cross-Reference	Balance at 12/31/2018	Disallowances	Prior Year Disallowances & Opening Balance Adjustments	Depreciation Provision	2019 Retirements	2019 Transfers	2019 Adjustments	2019 Net Salvage	Balance at 12/31/2019
21	Transmission		1,481.9	(1.8)	1,480.1	179.7	(27.5)	-	(3.5)	(10.7)	1,618.2
22											
23	**Direct General PP&E**										
24	Land		(0.1)	-	(0.1)	-	(0.0)	-	-	0.1	0.0
25	Structures and Improvements		22.0	-	22.0	2.8	(0.2)	-	-	(0.0)	24.5
26	Office Furniture and Equipment		5.6	-	5.6	0.8	(0.0)	-	-	(0.2)	6.2
27	Computer Equipment		0.3	-	0.3	0.1	(0.0)	-	-	-	0.4
28	Transportation Equipment		22.6	-	22.6	3.6	(1.2)	-	-	0.3	25.3
29	Tools and Instruments		12.5	-	12.5	3.3	(0.5)	-	-	-	15.3
30	Housing		0.5	-	0.5	-	-	-	-	-	0.5
31	Leasehold Improvements		3.2	-	3.2	1.2	(2.5)	-	-	-	2.0
32	Software		34.9	(0.3)	34.5	8.8	(7.0)	-	-	-	36.4
33	**Subtotal**		101.6	(0.3)	101.3	20.6	(11.4)	-	-	0.2	110.6
34											
35	**Total Transmission**	Sch 2.1-T	1,583.5	(2.1)	1,581.4	200.3	(39.0)	-	(3.5)	(10.5)	1,728.8
36											
37											
38											

39 * AFUDC is a component of all categories and is therefore not disclosed separately in this continuity schedule.

ATCO Electric Transmission (AET)
SUMMARY OF CAPITAL EXPENDITURES & ADDITIONS
FOR THE YEAR ENDED DECEMBER 31, 2019
($Millions)

Line No.	Project	Description	2019 Actual CWIP Balance	2019 Actual Cap Expend	2019 Actual Cap Adds	2019 Actual CWIP Balance	2019 Approved* CWIP Balance	2019 Approved* Cap Expend	2019 Approved* Cap Adds	2019 Approved* CWIP Balance	Higher/(Lower) Expenditures Actual to Approved	Var. %	Higher/(Lower) Additions Actual to Approved	Var. %
1		**CAPITAL MAINTENANCE**												
2		Transmission Capital Maintenance - Substations	22.5	34.1	36.4	20.2	12.6	33.4	37.3	8.7	0.7	2.1%	(0.9)	-2.4%
3		Transmission Capital Maintenance - Lines	7.6	16.6	20.8	3.4	(2.3)	9.5	10.0	(2.8)	7.1	74.7%	10.8	100.0%
4		Transmission System Right-of-Way	-	2.7	2.7	-	0.5	1.4	1.6	0.3	1.3	92.9%	1.1	68.8%
5		Transmission Rights-of-Way Widening	-	5.1	5.1	-	0.7	4.3	4.8	0.2	0.8	18.6%	0.3	6.3%
6		Substation Rebuilds	7.7	14.6	21.4	0.9	22.0	21.8	32.9	10.9	(7.2)	-33.0%	(11.5)	-35.0%
7		Transmission Line Ground Clearance	1.5	2.2	2.7	1.0	1.0	4.2	4.5	0.7	(2.0)	-47.6%	(1.8)	-40.0%
8		Transmission Line Rebuilds (Partial & Complete)	4.8	2.8	-	7.6	2.9	8.4	-	11.3	(5.6)	-66.7%	-	0.0%
9		Kearl 9L101	0.9	1.7	-	2.6	1.1	3.0	-	4.1	(1.3)	-43.3%	-	0.0%
10		Kearl Disallowance (para 444 in Decision 22742-D01-2019)	-	-	-	-	(1.0)	(3.0)	-	(4.0)	3.0	-100.0%	-	0.0%
11		Transmission Double Circuit	2.2	0.7	2.5	0.4	1.9	2.1	2.3	1.7	(1.4)	-66.7%	0.2	8.7%
12		Temporary Line Relocation- 9L66/9L92 (Phase 2 Joslyn - Muskeg)	-	0.4	-	0.4	-	-	-	-	0.4	100.0%	-	0.0%
13		Youngstown Substation Purchase	-	0.1	-	0.1	-	-	-	-	0.1	100.0%	-	0.0%
14		Reclassification of training costs from ES&G to O&M - Non DA portion	-	-	-	-	-	(0.1)	(0.1)	-	0.1	-100.0%	0.1	-100.0%
15		AUC Decision 22742-D01-2019 Directions 3, 6, 8	-	-	-	-	-	(3.6)	(3.6)	-	3.6	-100.0%	3.6	-100.0%
16			47.2	81.0	91.6	36.6	39.4	81.5	89.8	31.1	(0.5)	-0.6%	1.8	2.0%
17		**TELECOMMUNICATION**												
18		Telecommunication Capital Maintenance	2.8	5.9	7.0	1.7	2.0	4.5	4.7	1.8	1.4	31.1%	2.3	48.9%
19		Telecom Site Power Backup	-	-	-	-	0.1	-	-	0.1	-	0.0%	-	0.0%
20		Mobile Communication System	0.3	-	-	0.3	0.3	-	-	0.3	-	0.0%	-	0.0%
21		Network Multiplexor Upgrade	-	1.6	1.4	0.2	0.0	-	-	0.0	1.6	100.0%	1.4	100.0%
22		Telecom Tower Replacements	0.7	1.4	2.0	0.1	(2.1)	1.8	2.0	(2.3)	(0.4)	-22.2%	-	0.0%
23		Telecom Building Replacements/Refurbishments	0.8	1.1	1.8	0.1	1.2	-	-	1.2	1.1	100.0%	1.8	100.0%
24		Replacement of End of Life Radios	0.8	4.7	2.5	3.0	0.0	6.0	5.8	0.2	(1.3)	-21.7%	(3.3)	-56.9%
25		Telecom Capacity & Reliability Upgrade Projects	3.7	1.9	5.1	0.5	0.5	2.3	2.4	0.4	(0.4)	-17.4%	2.7	100.0%
26		Mobile Radio Expansion	4.5	2.2	5.9	0.8	4.5	1.5	1.5	4.5	0.7	46.7%	4.4	100.0%
27		AUC Decision 22742-D01-2019 Directions 3, 6, 8	-	-	-	-	-	(0.6)	(0.6)	-	0.6	-100.0%	0.6	-100.0%
28			13.6	18.8	25.7	6.7	6.8	15.5	15.8	6.5	3.3	21.1%	9.9	62.3%
29		**SCADA / EMS**												
30		Operational Information Systems	0.8	0.8	1.3	0.3	0.1	0.7	0.8	(0.0)	0.1	14.3%	0.5	62.5%
31		Regulatory Compliance & Security Programs	0.6	1.2	0.6	1.2	2.3	1.8	4.6	(0.5)	(0.6)	-33.3%	(4.0)	-87.0%
32		AUC Decision 22742-D01-2019 Directions 3, 6, 8	-	-	-	-	-	(0.0)	(0.0)	-	0.0	-100.0%	0.0	-100.0%
33			1.4	2.0	1.9	1.5	2.4	2.5	5.4	(0.5)	(0.5)	100.0%	(3.5)	-64.5%
34														
35		**TRANSMISSION ISOLATED GENERATION**												
36		Rebuild Jasper Palisades Substation	0.3	-	-	0.3	0.3	-	-	0.3	-	0.0%	-	0.0%
37		Refurbish/Replace Engines and Turbines	1.3	1.1	1.4	1.0	1.6	1.6	1.9	1.3	(0.5)	-31.3%	(0.5)	-26.3%
38		Transmission Isolated Operations Capital Maintenance	0.5	(0.1)	-	0.4	2.3	0.4	0.5	2.2	(0.5)	-100.0%	(0.5)	-100.0%
39		Install Alternate Power Supply/Renewables	2.9	5.4	4.4	3.9	1.4	5.1	6.2	0.3	0.3	5.9%	(1.8)	-29.0%
40		AUC Decision 22742-D01-2019 Directions 3, 6	-	-	-	-	-	(0.1)	(0.1)	-	0.1	-100.0%	0.1	-100.0%
41			5.0	6.4	5.8	5.6	5.5	7.0	8.5	4.0	(0.6)	-8.9%	(2.7)	-31.9%

ATCO Electric Transmission (AET)
SUMMARY OF CAPITAL EXPENDITURES & ADDITIONS
FOR THE YEAR ENDED DECEMBER 31, 2019
($Millions)

			2019 Actual					2019 Approved*							
Line No.	Project	Description	CWIP Balance	Cap Expend	Cap Adds	CWIP Balance		CWIP Balance	Cap Expend	Cap Adds	CWIP Balance	Higher/(Lower) Expenditures Actual to Approved	Var. %	Higher/(Lower) Additions Actual to Approved	Var. %
42															
43		**NORTH WEST FIRE 2019**	-	10.0	10.0	-		-	-	-	-	10.0	100.0%	10.0	100.0%
44															
45		**TOTAL CAPITAL MAINTENANCE**	67.2	118.2	135.0	50.4		54.1	106.5	119.5	41.1	11.7	11.0%	15.5	13.0%
46															
47		**DIRECT ASSIGNED PROJECTS SYSTEM**													
48	58001	Edmonton-Calgary 500 kV East Route	-	2.0	2.0	-		-	-	-	-	2.0	100.0%	2.0	100.0%
49	53043	Rycroft Transmission Reinforcement	0.8	0.4	-	1.2		1.1	2.8	-	3.9	(2.4)	-85.7%	-	0.0%
50	54904	Jasper Transmission Interconnection	58.0	54.8	112.8	-		60.6	26.7	86.8	0.5	28.1	100.0%	26.0	30.0%
51	55001	Salt Creek - 240-144kv Substation	-	-	-	-		0.1	-	-	0.1	-	-100.0%	-	-100.0%
52	55732	Livock Interconnection (55737)	-	-	-	-		0.0	-	-	0.0	-	0.0%	-	0.0%
53	55737	Thickwood Development	-	6.5	6.5	-		0.0	12.7	12.8	(0.0)	(6.2)	-49.0%	(6.3)	-49.2%
54	56772	Nevis Transformer	0.1	-	-	0.1		-	5.0	-	5.0	(5.0)	-100.0%	-	0.0%
55	57102	9LX02 (Boundary-Tinchebray)	-	-	-	-		0.5	-	-	0.5	-	0.0%	-	0.0%
56	57157	St. Paul Substation & Line	-	0.4	0.4	-		-	-	-	-	0.4	100.0%	0.4	100.0%
57	53594	Grande Prairie Transmission Reinforcement	0.2	-	-	0.2		0.2	-	-	0.2	-	0.0%	-	0.0%
58	57159	PENVTD	0.4	0.7	-	1.1		0.5	2.9	-	3.4	(2.2)	-75.7%	-	0.0%
59	58112	Central East Transfer Out	0.2	1.7	-	1.9		1.0	6.5	-	7.5	(4.8)	-73.8%	-	0.0%
60		Various Other Projects below $0.0 individually	-	0.1	0.1	-		-	-	-	-	0.1	100.0%	0.1	100.0%
61		AUC Decision 22742-D01-2019 Directions 3, 6, 8	-	-	-	-		-	(5.2)	(5.2)	-	5.2	-100.0%	5.2	-100.0%
62		**TOTAL DIRECT ASSIGNED PROJECTS - SYSTEM**	59.7	66.6	121.8	4.5		64.0	51.5	94.4	21.0	15.1	29.4%	27.4	29.0%
63															
64		**DIRECT ASSIGNED PROJECTS - CUSTOMER**													
65	51074	Fort Nelson Remedial Action Scheme	-	-	-	-		0.3	-	-	0.3	-	0.0%	-	0.0%
66	51090	Rainbow Lake Gas	-	0.1	-	0.1		-	-	-	-	0.1	100.0%	-	0.0%
67	51760	Fort Saskatchewan WAGF	0.1	-	-	0.1		0.1	-	-	0.1	-	0.0%	-	0.0%
68	51162	Blumenort - Windy Hills 144kV Transmission Line	1.5	-	-	1.5		1.4	-	-	1.4	-	0.0%	-	0.0%
69	51181	Three Creeks Power Plant	15.3	(15.3)	-	-	**Note 1**	15.3	14.6	-	29.9	(29.9)	-100.0%	-	0.0%
70	51440	Whitetail Peaking Station Interconnection	1.4	0.1	-	1.5		1.3	-	-	1.3	0.1	100.0%	-	0.0%
71	51745	Wabasca 25kV Breaker Addition	0.4	(0.4)	-	-	**Note 1**	0.4	-	-	0.4	(0.4)	-100.0%	-	0.0%
72	51750	Eureka River 861S Capacity Increase	-	-	-	-		0.0	-	-	0.0	-	0.0%	-	0.0%
73	53034	Ksituan River 754S Capacity Upgrade	5.9	2.3	8.2	-		7.4	1.3	8.6	0.1	1.0	76.9%	(0.4)	-4.7%
74	53455	M.D. Greenview Load	0.5	0.3	-	0.8		-	5.0	-	5.0	(4.7)	-94.0%	-	0.0%
75	53475	ATCO Woodlands Area Load	-	0.2	-	0.2		-	-	-	-	0.2	100.0%	-	0.0%
76	53593	Grande Prairie	6.3	0.6	-	6.9		6.1	12.2	-	18.3	(11.6)	-95.1%	-	0.0%
77	53730	Heriot POD	-	-	-	-		-	2.5	-	2.5	(2.5)	-100.0%	-	0.0%
78	54020	Muir POD	-	-	-	-		0.0	-	-	0.0	-	0.0%	-	0.0%
79	54501	Wapiti 823S Capacity Addition	-	-	-	-		(3.5)	-	-	(3.5)	-	0.0%	-	0.0%
80	55119	Generator Capacity Increase	0.1	0.9	-	1.0		1.2	15.5	-	16.7	(14.6)	-94.2%	-	0.0%
81	55634	Aspen SAGD	-	-	-	-		0.0	0.5	-	0.5	(0.5)	-100.0%	-	0.0%
82	55706	Edwards Lake Substation Connection	-	-	-	-		0.0	-	-	0.0	-	0.0%	-	0.0%
83	55709	CNLR Kirby North	0.1	-	0.1	-		-	-	-	-	-	0.0%	0.1	100.0%

ATCO Electric Transmission (AET)
SUMMARY OF CAPITAL EXPENDITURES & ADDITIONS
FOR THE YEAR ENDED DECEMBER 31, 2019
($Millions)

			2019 Actual					2019 Approved*							
Line No.	Project	Description	CWIP Balance	Cap Expend	Cap Adds	CWIP Balance		CWIP Balance	Cap Expend	Cap Adds	CWIP Balance	Higher/(Lower) Expenditures Actual to Approved	Var. %	Higher/(Lower) Additions Actual to Approved	Var. %
84	55753	Merritt Sub and Line	0.1	0.2	-	0.3		0.3	4.6	-	4.9	(4.4)	-95.7%	-	0.0%
85	56655	Kent Generation	-	-	-	-		0.0	-	-	0.0	-	0.0%	-	0.0%
86	56727	Cold Lake Area Cogen	-	0.2	-	0.2		-	-	-	-	0.2	100.0%	-	0.0%
87	56810	Grizzly Bear Wind Facility Connection	1.9	0.4	-	2.3		1.9	-	-	1.9	0.4	100.0%	-	0.0%
88	56815	Paintearth Wind Project	0.7	0.1	-	0.8		0.6	-	-	0.6	0.1	100.0%	-	0.0%
89	56820	Halkirk II Wind Power Facility	0.4	0.1	-	0.5		0.3	-	-	0.3	0.1	100.0%	-	0.0%
90	56865	Wainwright	0.1	-	-	0.1		0.1	-	-	0.1	-	0.0%	-	0.0%
91	56878	SAGD Foster Creek DTS Cap Upgrade	-	-	-	-		0.0	-	-	0.0	-	0.0%	-	0.0%
92	58180	Spirit River POD Substation	-	-	-	-		0.3	-	-	0.3	-	0.0%	-	0.0%
93	58181	Simonette 733S Substation Capacity Upgrade	-	-	-	-		0.2	-	-	0.2	-	0.0%	-	0.0%
94	58215	Sharp Hills Windfarm	3.0	1.8	-	4.8		2.1	15.8	17.9	0.0	(14.0)	-88.6%	(17.9)	-100.0%
95	58225	Garden Plain Wind	0.2	0.1	-	0.3		-	-	-	-	0.1	100.0%	-	0.0%
96	58562	Hand Hills Wind Project	0.7	(0.7)	-	-	**Note 1**	0.7	-	-	0.7	(0.7)	-100.0%	-	0.0%
97	58569	Hand Hills Wind Power Facility	0.5	(0.5)	-	-	**Note 1**	0.5	-	0.0	0.5	(0.5)	-100.0%	(0.0)	-100.0%
98	58578	Hand Hills WAGF	0.1	-	-	0.1		0.1	-	-	0.1	-	0.0%	-	0.0%
99	58574	Forestberg Area Solar	0.1	-	-	0.1		-	-	-	-	-	0.0%	-	0.0%
100	58843	Wheatland Wind New POS	0.4	0.1	-	0.5		0.3	-	-	0.3	0.1	100.0%	-	0.0%
101	58844	Echo Wind Power New POS	0.3	0.2	-	0.5		0.1	-	-	0.1	0.2	100.0%	-	0.0%
102	58922	Eyre 558S Substation Interconnection	0.3	-	-	0.3		0.3	-	-	0.3	-	0.0%	-	0.0%
103	58923	Currant Lake Substation	4.4	0.3	-	4.7		4.1	-	-	4.1	0.3	100.0%	-	0.0%
104	58924	Armitage Substation	5.1	0.4	-	5.5		4.7	-	-	4.7	0.4	100.0%	-	0.0%
105	58925	Cavendish Substation	5.5	0.7	-	6.2		5.1	-	-	5.1	0.7	100.0%	-	0.0%
106	58965	Heartland Pump Station	0.5	0.1	0.1	0.5		-	-	-	-	0.1	100.0%	0.1	100.0%
107	58970	Bohn 913S Substation Transformer Addition	-	-	-	-		0.0	-	-	0.0	-	0.0%	-	0.0%
108	58971	Bauer 918S Substation Transformer Addition	-	-	-	-		0.0	-	-	0.0	-	0.0%	-	0.0%
109	53441	Thornton DTS Increase	-	-	-	-		-	3.5	-	3.5	(3.5)	-100.0%	-	0.0%
110	55605	Line Tap	0.1	-	-	0.1		0.1	-	-	0.1	-	0.0%	-	0.0%
111	58145	Red Deer Battery Energy Storage System	0.3	-	-	0.3		0.3	-	-	0.3	-	0.0%	-	0.0%
112	58526	Oyen Wind Power Project	0.4	(0.4)	-	-	**Note 1**	0.3	-	-	0.3	(0.4)	-100.0%	-	0.0%
113	55145	ATCO 9L32/66	-	0.1	-	0.1		-	-	-	-	0.1	100.0%	-	0.0%
114	5X300	Other WAGF	-	-	-	-		0.9	3.5	4.4	-	(3.5)	-100.0%	(4.4)	-100.0%
115		Various Other Projects below $0.0 individually	0.2	-	(0.1)	0.3		0.3	-	-	0.3	-	0.0%	(0.1)	-100.0%
116		**TOTAL DIRECT ASSIGNED PROJECTS - CUSTOMER**	56.9	(8.0)	8.3	40.6		53.7	79.0	30.9	101.8	(87.0)	-110.1%	(22.6)	-73.1%
117															
118		Reclassification of training costs from ES&G to O&M - DA portion	-	-	-	-		-	(0.1)	(0.1)	-	0.1	-100.0%	0.1	-100.0%
119															
120		**TOTAL DIRECT ASSIGNED**	116.6	58.6	130.1	45.1		117.7	130.4	125.3	122.8	(71.8)	-55.1%	4.8	3.8%
121															
122		AUC Decision 22742-D01-2019 Direction 6	-	-	-	-		-	(0.2)	(0.2)	-	0.2	-100.0%	0.2	-100.0%
123															
124		Total Transmission	183.8	176.8	265.1	95.5		171.8	236.7	244.6	163.9	(59.9)	-25.3%	20.5	8.4%
125															

ATCO Electric Transmission (AET)
SUMMARY OF CAPITAL EXPENDITURES & ADDITIONS
FOR THE YEAR ENDED DECEMBER 31, 2019
($Millions)

			2019 Actual				2019 Approved*							
Line No.	Project	Description	CWIP Balance	Cap Expend	Cap Adds	CWIP Balance	CWIP Balance	Cap Expend	Cap Adds	CWIP Balance	Higher/(Lower) Expenditures Actual to Approved	Var. %	Higher/(Lower) Additions Actual to Approved	Var. %
126		**DIRECT GENERAL PP&E**												
127		Tools and Instruments	0.6	3.1	3.2	0.5	(0.0)	3.3	3.3	0.0	(0.2)	-7.2%	(0.1)	-3.0%
128		Transmission Asset Mgmt Program	-	0.5	0.5	-	0.4	0.4	0.4	0.4	0.1	25.0%	0.1	25.0%
129		Transportation Equipment	-	3.8	-	3.8	0.0	4.1	4.1	0.0	(0.3)	-8.1%	(4.1)	-100.0%
130			0.6	7.4	3.7	4.3	0.5	7.9	7.8	0.5	(0.5)	-6.1%	(4.1)	-52.7%
131														
132		**SOFTWARE**	5.0	8.7	6.3	7.4	7.0	11.5	16.3	2.1	(2.8)	-24.3%	(10.0)	-61.5%
133			5.0	8.7	6.3	7.4	7.0	11.5	16.3	2.1	(2.8)	-24.3%	(10.0)	-61.5%
134		**BUILDINGS**												
135		Office Furniture and Equipment	-	0.1	0.1	-	-	-	-	-	0.1	100.0%	0.1	100.0%
136		Land, Buildings and Structures	0.2	1.7	1.4	0.5	0.2	1.8	1.8	0.2	(0.1)	-5.6%	(0.4)	-22.2%
137			0.2	1.8	1.5	0.5	0.2	1.8	1.8	0.2	-	0.0%	(0.3)	-16.7%
138														
139			5.8	17.9	11.5	12.2	7.7	21.2	26.0	2.8				
140														
141		AUC Decision 22742-D01-2019 Directions 3, 6	-	-	-	-	-	(0.4)	(0.4)	-				
142		IT Common Matters Disallowance	-	(0.3)	(0.3)	-	-	-	-	-				
143														
144		**Total Transmission Capital Additions**	189.6	194.4	276.3	107.7	179.5	257.4	270.1	166.8				
145		Net Salvage			(10.5)				(4.0)					
146		Additions to Property			265.8				266.1					
147														
148														

149 **Note 1:** 2019 Opening WIP has been adjusted as these projects have been cancelled and there should have been no Opening WIP.

150

151 *** -** Per AET's 2018-2019 GTA Compliance Filing, Proceeding ID 24805, Exhibit X0005.01

ATCO Electric Transmission (AET)

SUMMARY OF CAPITAL CONTRIBUTIONS

FOR THE YEAR ENDED DECEMBER 31, 2019

($Millions)

Line No.	Project	Description	2019 Actual CWIP Balance	2019 Actual Cap Expend	2019 Actual Cap Adds	2019 Actual CWIP Balance	2019 Approved* CWIP Balance	2019 Approved* Cap Expend	2019 Approved* Cap Adds	2019 Approved* CWIP Balance	Higher/(Lower) Expenditures Actual to Approved	Var. %	Higher/(Lower) Additions Actual to Approved	Var. %
1	**DIRECT ASSIGNED PROJECTS**													
2	51074	Fort Nelson Remedial Action Scheme	-	(0.1)	(0.1)	-	0.4	-	-	0.4	(0.1)	-100.0%	(0.1)	-100.0%
3	51090	ATCO Power Rainbow Lake Gas	-	0.2	-	0.2	-	-	-	-	0.2	100.0%	-	0.0%
4	51162	Blumenort - Windy Hill 144 kV Transmission Line	1.4	-	-	1.4	1.4	-	-	1.4	-	0.0%	-	0.0%
5	51181	Three Creeks Power Plant	15.5	(14.5)	-	1.0	14.9	19.4	-	34.3	(33.9)	-100.0%	-	0.0%
6	51440	Whitetail Peaking Station Interconnection	1.6	-	-	1.6	1.6	-	-	1.6	-	0.0%	-	0.0%
7	51760	Fort Saskatchewan WAGF	0.1	-	-	0.1	0.1	-	-	0.1	-	0.0%	-	0.0%
8	53034	Ksituan River 754S Capacity Upgrade	5.1	(0.4)	4.7	-	5.3	-	5.3	-	(0.4)	100.0%	(0.6)	-11.3%
9	53324	STS Contract Capacity Increase	(0.1)	0.1	-	-	(0.1)	-	-	(0.1)	0.1	100.0%	-	0.0%
10	53440	Thornton New POD	-	(0.2)	(0.2)	-	-	-	-	-	(0.2)	-100.0%	(0.2)	-100.0%
11	53441	Thornton DTS Increase	-	-	-	-	-	1.3	-	1.3				
12	53593	Grande Prairie	-	-	-	-	-	9.0	-	9.0	(9.0)	-100.0%	-	0.0%
13	54954	Generator Increase	(0.1)	0.1	-	-	(0.1)	-	-	(0.1)	0.1	100.0%	-	0.0%
14	54955	Milner 2 Expansion	0.1	(0.1)	-	-	0.1	-	-	0.1	(0.1)	-100.0%	-	0.0%
15	55119	Generator Capacity Increase	1.6	-	-	1.6	1.6	16.0	-	17.6	(16.0)	-100.0%	-	0.0%
16	55145	ATCO 9L32/66	-	0.2		0.2	-	-	-	-	0.2	100.0%	-	0.0%
17	55187	Service for MacKay SAGD	(0.1)	0.1	-	-	-	-	-	-	0.1	100.0%	-	0.0%
18	55584	Green Stocking Substation	-	(1.0)	(1.0)	-	-	-	-	-	(1.0)	-100.0%	(1.0)	-100.0%
19	55605	Line Tap	0.2	-	-	0.2	0.3	-	-	0.3	-	0.0%	-	0.0%
20	55709	CNRL Kirby North	0.1	-	-	0.1	-	-	-	-	-	0.0%	-	0.0%
21	55735	Germain Substation and 144kV Line	-	0.1	0.1	-	-	-	-	-	0.1	100.0%	0.1	100.0%
22	56727	Pengrowth Cold Lake Area Cogen	-	0.6	-	0.6	-	-	-	-	0.6	100.0%	-	0.0%
23	56810	Grizzly Bear Wind Power Facility	2.1	-	-	2.1	2.1	-	-	2.1	-	0.0%	-	0.0%
24	56815	Paintearth Wind Project	0.7	-	-	0.7	0.6	-	-	0.6	-	0.0%	-	0.0%
25	56820	Halkirk II Wind Power Facility	0.8	-	-	0.8	0.8	-	-	0.8	-	0.0%	-	0.0%
26	56865	Wainwright	0.2	-	-	0.2	0.2	-	-	0.2	-	0.0%	-	0.0%
27	56878	SAGD Foster Creek DTS Cap Upgrade	0.2	(0.2)	-	-	0.2	-	-	0.2	(0.2)	-100.0%	-	0.0%
28	58145	Red Deer Battery Energy Storage System	0.4	-	-	0.4	0.4	-	-	0.4	-	0.0%	-	0.0%
29	58204	Battery Storage	0.1	-	-	0.1	0.1	-	-	0.1	-	0.0%	-	0.0%
30	58215	Wind Farm New Facility Generator Capacity	12.8	-	-	12.8	2.1	15.4	17.5	-	(15.4)	-100.0%	(17.5)	-100.0%
31	58225	Garden Plain Wind	0.3	-	-	0.3	0.3	-	-	0.3	-	0.0%	-	0.0%
32	58525	Oyen Wind Energy Project	0.1	-	-	0.1	0.1	-	-	0.1	-	0.0%	-	0.0%
33	58526	Oyen Wind Power Project	0.7	(0.7)	-	-	1.4	-	-	1.4	(0.7)	-100.0%	-	0.0%
34	58562	Hand Hills Wind Power Facility - 58562	0.7	-	-	0.7	0.7	-	-	0.7	-	0.0%	-	0.0%
35	58569	Hand Hills Wind Power Facility	0.5	0.5	-	1.0	0.5	-	-	0.5	0.5	100.0%	-	0.0%
36	58572	Hand Hills Wind Project Phase 2	0.2	(0.2)	-	-	0.2	-	-	0.2	(0.2)	-100.0%	-	0.0%
37	58573	Hand Hills Solar	0.2	(0.2)	-	-	0.2	-	-	0.2	(0.2)	-100.0%	-	0.0%
38	58574	Forestberg Area Solar	0.1	-	-	0.1	-	-	-	-	-	0.0%	-	0.0%
39	58578	Hand Hills WAGF	0.1	-	-	0.1	0.1	-	-	0.1	-	0.0%	-	0.0%
40	58843	Wheatland Wind New POS	0.5	-	-	0.5	0.5	-	-	0.5	-	0.0%	-	0.0%
41	58844	Echo Wind Power New POS	1.2	-	-	1.2	1.2	-	-	1.2	-	0.0%	-	0.0%
42	58922	Eyre 558S Substation Interconnection	0.1	-	-	0.1	0.1	-	-	0.1	-	0.0%	-	0.0%
43	58925	Cavendish Substation	1.0	-	-	1.0	1.0	-	-	1.0	-	0.0%	-	0.0%
44	5X300	Other WAGF	-	-	-	-	0.9	3.5	-	4.4	(3.5)	200.0%	-	0.0%
45		Rounding	-	-	-	-	(0.3)	-	-	(0.3)	-	300.0%	-	100.0%
46			48.4	(15.7)	3.5	29.2	38.9	64.6	22.8	80.7	(80.3)	400.0%	(19.3)	200.0%
47	**OTHER TRANSMISSION**													
48		Kearl 9L101	-	19.0	-	19.0	-	-	-	-	19.0	100.0%	-	-100.0%
49		Substation Capital Maintenance	0.5	0.5	0.4	0.6	0.4	0.3	0.4	0.3	0.2	66.7%	-	-100.0%
50		Lines Capital Maintenance	0.3	(0.3)	-	0.0	0.8	1.0	1.2	0.6	(1.3)	-130.0%	(1.2)	-100.0%
51		Refurbish/Replace Engines and Turbines	-	-	-	-	(0.2)	-	-	(0.2)	-	0.0%	-	-100.0%
52		Telecom Capital Maintenance - General	-	0.1	0.1	-	-	-	-	-	0.1	100.0%	0.1	100.0%
53		Replacement of End of Life Radios	-	-	-	-	(0.1)	-	-	(0.1)	-	0.0%	-	0.0%
54		Refurbish/Replace Engines and Turbines - ISO	-	-	-	-	0.2	-	-	0.2	-	-100.0%	-	0.0%
55		Rounding	-	-	-	-	(0.1)	-	-	(0.1)	-	-100.0%	-	0.0%
56			0.8	19.3	0.5	19.6	1.0	1.3	1.6	0.7	18.0	0.0%	(1.1)	-68.8%
57														
58			49.2	3.6	4.0	48.8	39.9	65.9	24.4	81.4				
59														
60														

61 *** -** Per AET's 2018-2019 GTA Compliance Filing, Proceeding ID 24805, Exhibit X0005.01

ATCO Electric Transmission (AET)
VARIANCE EXPLANATIONS OF CAPITAL EXPENDITURES
FOR THE YEAR ENDED DECEMBER 31, 2019
($Millions)

Line No.	Project	Description	2019 Actual Expend	2019 Approved* Expend	Variance Actual to Approved	Var %	Variance Explanation
1	**CAPITAL MAINTENANCE**						
2		Transmission Capital Maintenance - Lines	16.5	9.5	7.0	73.7%	Higher due mainly to delays in work from 2018 to 2019, and higher costs relating to AC mitigation.
3		Transmission System Right-of-Way	2.7	1.4	1.3	92.9%	Higher due mainly to data capture and analysis in support of minimizing wildfire risk address by the Right-of-Way program.
4		Substation Rebuilds	14.4	21.8	(7.4)	-33.9%	Lower due mainly to a combination of lower overall project costs based on detailed execution scope and lower than anticipated labour costs. In addition, work scope was advanced from 2019 into 2018 resulting in lower 2019 expenditures.
5		Transmission Line Ground Clearance2	2.2	4.2	(2.0)	-47.6%	Lower due mainly to reduced scope after detailed design, project delays into 2020 and projects no longer required.
6		Transmission Lines Rebuild (Partial & Complete)	2.8	8.4	(5.6)	-66.7%	Lower due mainly to advancement of materials into 2018 and subsequent delay of land and permitting activities into 2020.
7		Kearl 9L1011	1.7	3.0	(1.3)	-43.3%	Lower due mainly to delay of material procurement into 2020.
8		Transmission Double Circuit	0.7	2.1	(1.4)	-66.7%	Lower due mainly to reduced scope after detailed design, project delays into 2020 and projects no longer required.
9							
10	**TELECOMMUNICATION**						
11		Telecommunication Capital Maintenance	5.9	4.5	1.4	31.1%	Higher due mainly to the occurrence of an emergency project and costs being delayed from 2018 into 2019.
12		Network Mulitplexor Upgrade	1.6	-	1.6	100.0%	Higher due mainly to delays in construction from 2018 to 2019.
13		Telecom Building Replacements/Refurbishments	1.1	-	1.1	100.0%	Higher due mainly to delay in construction from 2018 to 2019.
14		Replacement of End of Life Radios	4.7	6.0	(1.3)	-21.7%	Lower due mainly to project delays into 2020.
15							
16	**NORTH WEST FIRE 2019**		10.0	0.0	10.0	100.0%	These are unanticipated costs for reconstructing transmission facilities in the Northwest area of the province required as a result of wild fires in May and June of 2019. This project included activities associated with ensuring public safety from electrical hazards during and following evacuations, contingencies undertaken during the events to mitigate risks created by the wildfires, and all activities associated with replacement and investigation of damaged overhead powerlines.
17							
18	**DIRECT ASSIGNED PROJECTS - SYSTEM**						
19	53043	Rycroft Transmission Reinforcement	0.4	2.8	(2.4)	-85.7%	Lower due mainly to project delays resulting from delay in receiving the Functional Specification from the AESO.
20	54904	Jasper Transmission Interconnection	54.8	26.7	28.1	105.2%	Higher due mainly to higher matting and line construction costs due to increased external stakeholders requirements.
21	55737	Thickwood Development	6.5	12.7	(6.2)	-48.8%	Lower due mainly to advancement of expenditures from 2019 into 2018 as well as delay of AC Mitigation work to 2020.
22	56772	Nevis Transformer	0.0	5.0	(5.0)	-100.0%	Lower due to project cancellation.
23	57159	PENVTD	0.7	2.9	(2.2)	-75.9%	Lower due mainly to project delays related to AUC hearing and landowner issues.
24	58001	Edmonton-Calgary 500 kV East Route	2.0	0.0	2.0	100.0%	Higher due mainly to increased efforts to support the EATL project through the Deferral Application proceeding.
25	58112	Central East Transfer Out	1.7	6.5	(4.8)	-73.8%	Lower due mainly to delay in project activities as a result of re-baselining the project schedule based on the Functional Specification and delays in the NID and FA filing dates based on AESO direction.
26							

ATCO Electric Transmission (AET)

VARIANCE EXPLANATIONS OF CAPITAL EXPENDITURES

FOR THE YEAR ENDED DECEMBER 31, 2019

($Millions)

Line No.	Project	Description	2019 Actual Expend	2019 Approved* Expend	Variance Actual to Approved	Var %	Variance Explanation
27	**DIRECT ASSIGNED PROJECTS - CUSTOMER**						
28	51181	Three Creeks Power Plant	(15.3)	14.6	(29.9)	-204.8%	Lower due to project cancellation.
29	53730	Heriot POD	0.0	2.5	(2.5)	-100.0%	Lower due to project cancellation.
30	53441	Thornton DTS Increase	0.0	3.5	(3.5)	-100.0%	Lower due to project cancellation.
31	53455	M.D. Greenview Load	0.0	5.0	(5.0)	-100.0%	Lower due to customer request to delay the project.
32	53593	Grande Prairie	0.6	12.2	(11.6)	-95.1%	Lower due mainly to delays in receiving revised Functional Specification from the AESO, therefore delaying engineering and procurement of equipment.
33	55119	Generator Capacity Increase	0.9	15.5	(14.6)	-94.2%	Lower due mainly to customer delays in completing the connection proposal.
34	55753	Merritt Sub and Line	0.2	4.6	(4.4)	-95.7%	Lower due mainly to the customer request to put the project on hold.
35	58215	Sharp Hills Windfarm	1.8	15.8	(14.0)	-88.6%	Lower due mainly to delay customer request to delay construction to a future period.
36	5X300	Other WAGF	0.0	3.5	(3.5)	-100.0%	Lower due mainly to less WAGF project activity than was estimated.
37							
38	**SOFTWARE**		8.7	11.5	(2.8)	-24.3%	Lower due mainly to the delay in scheduled start date of Facilities & Asset Management from 2019 to 2020.
39							

***** - Per AET's 2018-2019 GTA Compliance Filing, Proceeding ID 24805, Exhibit X0005.01

ATCO Electric Transmission (AET)
VARIANCE EXPLANATIONS OF CAPITAL ADDITIONS
FOR THE YEAR ENDED DECEMBER 31, 2019
($Millions)

Line No.	Project	Description	2019 Actual Adds	2019 Approved* Adds	Variance Actual to Approved	Var %	Variance Explanation
1	**CAPITAL MAINTENANCE**						
2		Transmission Capital Maintenance - Lines	20.8	10.0	10.8	108.0%	Higher due mainly to delays in capitalizations from 2018 to 2019, and higher costs relating to AC mitigation.
3		Transmission System Right-of-Way	2.7	1.6	1.1	68.8%	Higher due mainly to data capture and analysis in support of minimizing wildfire risk address by the Right-of-Way program.
4		Substation Rebuilds	21.4	32.9	(11.5)	-35.0%	Lower due mainly to a combination of lower overall project costs based on detailed execution scope and lower than anticipated labour costs. In addition, work scope was advanced from 2019 into 2018 resulting in lower 2019 expenditures.
5		Transmission Line Ground Clearance	2.7	4.5	(1.8)	-40.0%	Lower due mainly to reduced scope after detailed design, project delays into 2020 and projects no longer required.
6							
7	**TELECOMMUNICATION**						
8		Telecommunication Capital Maintenance	7.0	4.7	2.3	48.9%	Higher due mainly to delays in capitalization from 2018 to 2019 and the occurrence of an emergency project.
9		Mobile Radio Expansion	5.9	1.5	4.4	293.3%	Higher due mainly to delays in capitalizations from 2018 to 2019. In addition, overall program costs were higher than anticipated.
10		Network Mulitplexor Upgrade	1.4	0.0	1.4	100.0%	Higher due mainly to delays in project capitalizations from 2018 to 2019.
11		Telecom Building Replacements/Refurbishments	1.8	0.0	1.8	100.0%	Higher due mainly to delay in capitalization from 2018 to 2019 and higher costs than anticipated.
12		Telecom Capacity & Reliability Upgrade Projects	5.1	2.4	2.7	112.5%	Higher due mainly to delay in capitalization from 2018 to 2019 and higher costs than anticipated
13		Replacement of End of Life Radios	2.5	5.8	(3.3)	-56.9%	Lower due mainly to project delays into 2020.
14							
15	**SCADA / EMS**						
16		Regulatory Compliance & Security Programs	0.6	4.6	(4.0)	-87.0%	Lower due mainly to advancement of capitalizations from 2019 into 2018.
17							
18	**TRANSMISSION ISOLATED GENERATION**						
19		Install Alternate Power Supply/Renewables	4.4	6.2	(1.8)	-29.0%	Lower due mainly to project delays into 2020.
20							
21	**NORTH WEST FIRE 2019**		10.0	0.0	10.0	100.0%	These are unanticipated costs for reconstructing transmission facilities in the Northwest area of the province required as a result of wild fires in May and June of 2019. This project included activities associated with ensuring public safety from electrical hazards during and following evacuations, contingencies undertaken during the events to mitigate risks created by the wildfires, and all activities associated with replacement and investigation of damaged overhead powerlines.
22							

ATCO Electric Transmission (AET)
VARIANCE EXPLANATIONS OF CAPITAL ADDITIONS
FOR THE YEAR ENDED DECEMBER 31, 2019
($Millions)

Line No.	Project	Description	2019 Actual Adds	2019 Approved* Adds	Variance Actual to Approved	Var %	Variance Explanation
23	**DIRECT ASSIGNED PROJECTS - SYSTEM**						
24	54904	Jasper Transmission Interconnection	112.8	86.8	26.0	30.0%	Higher due mainly to higher matting and line construction costs due to increased external stakeholders requirements.
25	55737	Thickwood Development	6.5	12.8	(6.3)	-49.2%	Lower due mainly to advancement of expenditures from 2019 into 2018 as well as delay of AC Mitigation work to 2020.
26	58001	Edmonton-Calgary 500 kV East Route	2.0	0.0	2.0	100.0%	Higher due mainly to increased efforts to support the EATL project through the Deferral Application proceeding
27							
28							
29	**DIRECT ASSIGNED PROJECTS - CUSTOMER**						
30	58215	Sharp Hills Windfarm	0.0	17.9	(17.9)	-100.0%	Lower due mainly to delay customer request to delay construction to a future period.
31	5X300	Other WAGF	0.0	4.4	(4.4)	-100.0%	Lower due mainly to less WAGF project activity than was estimated.
32							
33	**DIRECT GENERAL PP&E**						
34		Transportation Equipment	0.0	4.1	(4.1)	-100.0%	Lower due mainly to upfitting new vehicles delayed into 2020.
35							
36	**SOFTWARE**		6.3	16.3	(10.0)	-61.3%	Lower due mainly to the delay in scheduled start date of Facilities & Asset Management from 2019 to 2020.

***** - Per AET's 2018-2019 GTA Compliance Filing, Proceeding ID 24805, Exhibit X0005.01

ATCO Electric Transmission (AET)
VARIANCE EXPLANATIONS OF CONTRIBUTION EXPENDITURES
FOR THE YEAR ENDED DECEMBER 31, 2019
($Millions)

Line No.	Project	Description	2019 Actual Expend	2019 Approved* Expend	Variance Actual to Approved	Var %	Variance Explanation
1	**DIRECT ASSIGNED PROJECTS**						
2	51181	Three Creeks Power Plant	(14.5)	19.4	(33.9)	-174.7%	Lower due to project cancellation.
3	53441	Thornton DTS Increase	0.0	1.3			
4	53593	Grand Prairie	0.0	9.0	(9.0)	-100.0%	Lower due to delays in receiving revised Functional Specification from the AESO, therefore delaying the requirement for additional funding.
5	55119	Generator Capacity Increase	0.0	16.0	(16.0)	-100.0%	Lower due to customer delays in completing the connection proposal, therefore delaying the requirement for additional funding.
6	58215	Wind Farm New Facility Generator Capacity	0.0	15.4	(15.4)	-100.0%	Lower due to customer request to delay construction to a future period, therefore delaying the requirement for additional funding.
7	5X300	Other WAGF	0.0	3.5	(3.5)	-100.0%	Lower due to WAGF project activity that was lower than forecast.
8							
9	**OTHER TRANSMISSION**						
10		Kearl 9L101	19.0	0.0	19.0	100.0%	To allow the project to meet the required completion date, AET has received full project funding, pending the outcome of the Commissions determination regarding systemization of costs in Proceeding 25282.
11							
12		Lines Capital Maintenance	(0.3)	1.0	(1.3)	-130.0%	Lower due mainly to fewer customer projects.

***** - Per AET's 2018-2019 GTA Compliance Filing, Proceeding ID 24805, Exhibit X0005.01

ATCO Electric Transmission (AET)
VARIANCE EXPLANATIONS OF CONTRIBUTION ADDITIONS
FOR THE YEAR ENDED DECEMBER 31, 2019
($Millions)

Line No.	Project	Description	2019 Actual Adds	2019 Approved* Adds	Variance Actual to Approved	Var %	Variance Explanation
1	**DIRECT ASSIGNED PROJECTS**						
2	58215	Wind Farm New Facility Generator Capacity	0.0	15.4	(15.4)	-100.0%	Lower due to the customer request to delay construction to a future period, therefore delaying the requirement for additional funding.
3							
4	**OTHER TRANSMISSION**						
5		Lines Capital Maintenance	(0.3)	1.0	(1.3)	-130.0%	Lower due mainly to fewer customer projects.

***** - Per AET's 2018-2019 GTA Compliance Filing, Proceeding ID 24805, Exhibit X0005.01

ATCO Electric Transmission (AET)
SUMMARY OF UTILITY INCOME TAX
FOR THE YEAR ENDED DECEMBER 31, 2019
($Millions)

Line No.	Description	Cross-Reference	2019 Actual	2019 Approved*	2018 Actual	Var. Actual to Approved	Var. %	Var. Actual to Prior Year	Var. %	Working Paper Reference
1	Current Tax									
2	Federal Income Tax									
3	Federal Taxable Income		37.8	53.8	(12.3)	(16.1)	-29.8%	50.1	-407.9%	
4	Income Tax Rate		15.0%	15.0%	15.0%	-	0.0%	-	0.0%	
5	**Total Federal Income Tax**		**5.7**	**8.1**	**(1.8)**	**(2.4)**	**-29.8%**	**7.5**	**-407.9%**	
6										
7	Provincial Income Tax									
8	Federal Taxable Income		37.8	53.8	(12.3)	(16.1)	-29.8%	50.1	-407.9%	
9	Add: CCA Federal Flowthrough		320.9	302.3	316.1	18.6	6.2%	4.9	1.5%	
10	Less: CCA Provincial Flowthrough		322.7	302.3	316.1	20.5	6.8%	6.7	2.1%	
11	Provincial Taxable Income		36.0	53.9	(12.3)	(17.9)	-33.2%	48.3	-393.2%	
12	Income Tax Rate		11.5%	11.5%	12.0%	-	0.0%	(0.0)	-4.2%	
13	**Provincial Income Tax**		**4.1**	**6.2**	**(1.5)**	**(2.1)**	**-33.2%**	**5.6**	**-381.0%**	
14	Prior Year Adjustment		(0.1)	-	(3.2)	(0.1)	0.0%	3.0	100.0%	
15	**Total Current Tax**		**9.7**	**14.3**	**(6.5)**	**(4.6)**	**-32.2%**	**16.2**	**-249.2%**	
16										
17	Future Tax									
18	Temporary Differences		180.0	158.4	198.7	21.6	13.6%	(18.6)	-9.4%	
19	Income Tax Rate		15.0%	15.0%	15.0%	-	0.0%	-	0.0%	
20			27.0	23.8	29.8	3.2	13.6%	(2.8)	-9.4%	
21	**Total Future Tax**		**27.0**	**23.8**	**29.8**	**3.2**	**13.6%**	**(2.8)**	**-9.4%**	
22										
23	Other Items									
24	Preferred Dividend Tax		1.5	1.5	1.5	0.0	0.0%	(0.0)	0.0%	
25	**Total Other Items**		**1.5**	**1.5**	**1.5**	**0.0**	**0.0%**	**(0.0)**	**0.0%**	
26										
27	**Transmission Income Tax**		**38.1**	**39.5**	**24.8**	**(1.4)**	**-3.4%**	**13.4**	**53.9%**	
28										
29	Farms, Irrigation Transmission									
30	Utility Income Tax Expense		0.3	0.4	0.3	(0.1)	-17.4%	0.0	10.0%	
31										
32	**Total Transmission Income Tax**	Sch 1.0-T	**38.5**	**39.9**	**25.1**	**(1.4)**	**-3.6%**	**13.4**	**53.4%**	
33										
34										
35	***** - Per AET's 2018-2019 GTA Compliance Filing, Proceeding ID 24805, Exhibit X0005.01									

ATCO Electric Transmission (AET)

ANALYSIS OF AFFILIATE COST OF GOODS SOLD

FOR THE YEAR ENDED DECEMBER 31, 2019

($Millions)

Line No.	Service	Cross-Reference	Affiliate	2019 Actual Amount	2019 Approved* Amount	Var. Actual to Approved	Var. %	Working Paper Reference
1	**Transmission Affiliate Cost of Goods Sold**							
2	Operations & Maintenance		Alberta PowerLine	6.7	3.3	3.4	103.9%	**Note 1**
3	Engineering and Project Services		ATCO Power Canada Ltd.	0.4	-	0.4	100.0%	
4	Project and Asset Management Services		ATCO Energy Services Ltd.	0.5	-	0.5	100.0%	
5	Project and Asset Management Services		ATCO Power 2010 Ltd.	14.1	2.4	11.7	493.0%	**Note 2**
6	Tower and Circuit Leases		ATCO Gas	0.1	-	0.1	100.0%	
7	Project Services		Aschor	0.3	-	0.3	100.0%	
8	Other items individually less than $0.1			-	-	-	100.0%	
9								
10	**Isolated Generation Affiliate Cost of Goods Sold**							
11	Operations & Maintenance		ATCO Electric Distribution	-	-	-	100.0%	
12	Other items individually less than $0.1			-	-	-	100.0%	
13								
14	**Total Affiliate Cost of Goods Sold**			**22.0**	**5.6**	**16.3**	289.9%	
15								
16	* - Per AET's 2018-2019 GTA Compliance Filing, Proceeding ID 24805, Exhibit X0005.01							

Note 1 2019 Actuals are higher than 2019 approved by ($3.4) mainly due to flowthrough services provided of ($4.0) which do not attract an overhead burden. Cost are incurred and billed directly to the affiliate, and thus are a flow through. These cost are not forecasted by AET and have no impact to revenue requirement. This variance is partially offset by lower internal labour requirements of ($0.5)

Note 2 2019 Actuals are higher than 2019 approved by ($11.7) mainly due to flow-through services provided of ($9.5) which do not attract an overhead burden. Cost are incurred and billed directly to the affiliate, and thus are a flow through. These costs are not forecast by AET and have no impact on revenue requirement. The variance is also due to increased labour and fringe requirements of ($2.6) and partially offset by overhead cost of ($0.5).

ATCO Electric Transmission (AET)
ANALYSIS OF AFFILIATE COST OF GOODS SOLD (CORPORATE)
FOR THE YEAR ENDED DECEMBER 31, 2019
($Millions)

Line No.	Nature of Service	Affiliate	Cross-Ref.	2019 Actual Amount	2019 Approved* Amount	Var. Actual to Approved	Var. %	Working Paper Reference
1	**Corporate Affiliate Cost of Goods Sold**							
2	Administrative Services	Alberta PowerLine		0.3	1.3	(1.0)	-75.3%	**Note 1**
3	Administrative Services	Northland Utilities (NWT) Limited		0.5	0.1	0.4	416.4%	
4	Administrative Services	Yukon Electrical Company Limited		0.1	0.2	(0.1)	-36.7%	
5	Administrative Services	Northland Utilities (Yellowknife) Limited		0.1	0.1	0.0	16.3%	
6								
7	**Total Affiliate Cost of Goods Sold**			**1.1**	**1.7**	**(0.6)**	-36.6%	
8								
9	* - Per AET's 2018-2019 GTA Compliance Filing, Proceeding ID 24805, Exhibit X0005.01							

Note 1 2019 Actuals are lower than 2019 approved by ($1.0) due to lower internal labour and fringe requirements of ($0.9) and overhead burden of ($0.2).

ATCO Electric Transmission (AET)
SUMMARY OF PAYROLL AND MANPOWER STATISTICS
FOR THE YEAR ENDED DECEMBER 31, 2019
($Millions)

SALARIES, WAGES AND EMPLOYEE BENEFITS

Line No.	Description	Cross-Reference	2019 Actual	2019 Approved	2018 Actual	Var. Actual to Approved	Var. %	Var. Actual to Prior Year	Var. %	Working Paper Reference
1	Salaries, Wages and Employee Benefits									
2	Transmission Operations		25.0	25.3	32.0	(0.3)	-1.0%	(7.0)	-21.8%	
3	Transmission Capital		57.6	56.2	49.3	1.4	2.5%	8.3	16.8%	
4	Transmission Corporate - Operations		11.1	12.1	9.1	(1.1)	-8.7%	1.9	21.2%	
5	Transmission Corporate - Capital		6.9	8.9	7.6	(2.0)	-22.5%	(0.7)	-9.5%	
6										
7	**Salaries, Wages and Employee Benefits Charged to Utility Operations**		100.6	102.5	98.1	(1.9)	-1.9%	2.5	2.6%	

EMPLOYEE ALLOCATION

Line No.	Description	Cross-Reference	2019 Actual*	2019 Approved*	2018 Actual*	Var. Actual to Approved	Var. %	Var. Actual to Prior Year	Var. %	Working Paper Reference
8	Manpower Statistics									
9	Total Regular Employees (FTEs)		625.0	647.6	695.4	(22.6)	0.0%	(70.4)	-10.1%	
10	Total Temporary Employees (FTEs)		16.4	20.6	20.9	(4.2)	0.0%	(4.6)	-21.8%	
11	**Total Manpower**		641.4	668.2	716.4	(26.8)	0.0%	(75.0)	-10.5%	
12	Less:									
13	Allocated to Non-regulated		4.6	-	0.3					
14	**Total Manpower - Utility Operations**		636.8	668.2	716.1					
15										
16	Manpower Statistics									
17	Total Regular Employees (HC)		609.2	631.0	635.7	(21.8)	-3.5%	(26.5)	-4.2%	
18	Total Temporary Employees (HCs)		11.8	10.8	11.1	1.0	9.3%	0.7	6.3%	
19	**Total Manpower**		621.0	641.8	646.8	(20.8)	-3.2%	(25.8)	-4.0%	
20	Less:									
21	Allocated to Non-regulated		4.5	-	0.3					
22	**Total Manpower - Utility Operations**		616.5	641.8	646.5					

* - Per AET's 2018-2019 GTA Compliance Filing, Proceeding ID 24805, Exhibit X0005.01
** - AET has provided additional Manpower Statistics using the Headcount (HC) methodology, as AET is applying to transition to reporting HC as part of Proceeding 24964.

ATCO Electric Transmission (AET)
SUMMARY OF RESERVE/DEFERRAL ACCOUNTS
FOR THE YEAR ENDED DECEMBER 31, 2019
($Millions)

			2019 Actual					2019 Approved*				
Line No.	Description	Cross-Ref.	Opening Balance	Adds	Provision	Adjustments	Ending Balance	Opening Balance	Adds	Provision	Adjustments	Ending Balance
1	List of Reserve/Deferral Accounts											
2												
3	Reserve for Injuries and Damages		0.7	(1.5)	(0.0)	0.0	(0.8)	(7.2)	(0.5)	(0.0)	-	(7.7)
4	Variable Pay Program (VPP)		6.8	(3.7)	4.0	-	7.1	6.8	(3.9)	4.0	-	6.9
5	Vegetation Management		0.0	(10.1)	10.0	-	(0.0)	0.0	(10.0)	10.0	-	0.0
6												
7	**Total Deferred Assets**		7.5	(15.3)	14.0	0.0	6.3	(0.4)	(14.4)	14.0	-	(0.8)
8												
9	Federal Future Income Tax		190.8	-	23.8	-	214.6	190.4	0.3	23.8	-	214.4
10												
11	**Total Deferred Liabilities**		190.8	-	23.8	-	214.6	190.4	0.3	23.8	-	214.4

* - Per AET's 2018-2019 GTA Compliance Filing, Proceeding ID 24805, Exhibit X0005.01

ATCO Electric Transmission (AET)
Summary of Pension Plan Contributions
For the Year Ended December 31, 2019
($Millions)

ATCO Electric has provided the following information below in response to Direction 13 from AUC Decision 2010-189 which indicated:

The Commission would also like to establish the ability to monitor contributions into the Pension Plan. In this regard the Commission directs ATCO Utilities in its respective annual Rule 005: Annual Reporting Requirements of Operational and Financial Results (Rule 005) filings to include the following information:

i) The amounts contributed to the Pension Plan on a calendar year basis by each of the ATCO Utilities (broken down by utility) and the amounts contributed by the unregulated companies participating in the Pension Plan collectively. In reporting these contributions, the report should separately identify, amounts contributed as service costs under each of the DB Plan and the DC Plan and amounts contributed in respect of the DB Plan unfunded liability.

2019 Actual

	Defined Benefit Pension Expense		Defined Contribution Pension Expens	**Total**
	Service Amount	Special Payment	Service Amount	
ATCO Electric (Note 1)	2.8	-	3.7	**6.5**
ATCO Other	4.1	-	6.5	**10.6**

2019 Forecast (per AET 2018-2019 GTA)

	Defined Benefit Pension Expense		Defined Contribution Pension Expens	**Total**
	Service Amount	Special Payment	Service Amount	
ATCO Electric (Note 2)	3.2	-	Note 4	**3.2**
ATCO Other (Note 3)	3.6	-	Note 4	**3.6**

Note 1 - The actual defined benefit and defined contribution service amounts along with the special payment do not include amounts that are allocated from the ATCO Head office.
This amount includes COLA at 100%
Note 2 - ATCO Electric's portion of the estimated employer's current service cost as per the Mercer report as at Dec 31, 2017 filed in the AET 2018-2019 GTA,
Exhibit 22742-X0572.02(CL), AET Information Responses Round 3 to CCA Part 3 of 3, PDF Page 171.
Note 3 - ATCO Other's portion of the estimated employer's current service cost as per the Mercer report as at Dec 31, 2017 filed in the AET 2018-2019 GTA,
Exhibit 22742-X0572.02(CL), AET Information Responses Round 3 to CCA Part 3 of 3, PDF Page 171.
Note 4 - Not available given pension common matters application only addresses DB plan.

ii) A reconciliation in respect of the previous calendar year, by utility, of amounts collected through rates in respect of pension funding obligations with amounts contributed to the pension plan including amounts in the deferral account approved in accordance with this Decision.

<u>2018 Reconciliation (ATCO Electric - Transmission):</u>
2018 Special Payment Pension costs included in ATCO Electric Transmission's Revenue Requirement (Note 5)
2018 Actual Special Payment Pension contributions (Note 6)
2018 Actual Special Payment Pension contributions - allocated from ATCO Head Office (Note 6)
Refund/(collection) to / (from) customers

Note 5 - Per ATCO Electric Transmission 2018-2019 GTA Compliance Filing (Exhibit 24805-X0004, Schedule 3, Line 6)
Note 6 - Per ATCO Utilities Pension Application, Proceeding ID 21831, Exhibit 0006, Appendix 3

Accordingly the deferral account should be calculated as the annual difference between the amounts collected in rates in respect of the special payments and the special payment amounts actually paid by ATCO Utilities pursuant to the Pension Valuation(s) accepted by the Superintendent of Pensions that were in force during such year.

<u>2019 Reconciliation (ATCO Electric - Transmission):</u>
2019 Special Payment Pension costs included in ATCO Electric Transmission's Revenue Requirement (Note 7)
2019 Actual Special Payment Pension contributions (Note 8)
2019 Actual Special Payment Pension contributions - allocated from ATCO Head Office (Note 8)
Refund/(collection) to / (from) customers

Note 7 - Per ATCO Electric Transmission 2018-2019 GTA Compliance Filing (Exhibit 24805-X0004, Schedule 3, Line 6)
Note 8 - Per ATCO Utilities Pension Application, Proceeding ID 21831, Exhibit 0006, Appendix 3

iii) Confirmation of the date of any actuarial valuation reports filed with the Superintendent of Pensions since the last Rule 005 filing, and the associated impact of any filings on the pension funding requirements of each of the ATCO Utilities.

The Mercer 2017 CU Pension Plan Report was filed with the Superintendent of Pensions in July 13, 2018. The required pension funding contributions for ATCO Electric Transmission beginning January 1, 2019 are $3.2 million for current service and $0.0 million for special payments.

ATCO Electric Transmission (AET)

RECONCILIATION OF FINANCIAL REPORTING SCHEDULES TO AUDITED FINANCIAL STATEMENTS (TRANSMISSION & DISTRIBUTION)

FOR THE YEAR ENDED DECEMBER 31, 2019

INCOME STATEMENT ITEMS

($Millions)

Line No.	Description	Cross-Reference	Audited Financial Statements	Intercompany Eliminations	Distribution Financial Statements	Transmission Financial Statements	Transmission Utility Adjustments	Transmission Utility Total
			(see attached)					
1	**Revenues**		**1,288.1**	**(443.2)**	**975.7**	**755.6**		
2								
3	Impact of AUC Decisions						18.1	
4	Eliminate Non-Utility Revenues						(27.8)	
5	Reclassification of Revenue Offsets						(26.8)	
6	Reclass of Amortization of Contributions to Depreciation						(11.0)	
7	Reclass of Amortization of Cancelled Project Contributions						(14.5)	
8	Non IFRS Deferral Revenue						(6.0)	
9	Other						(1.6)	
10								
11		Sch 1	1,288.1	(443.2)	975.7	755.6	(69.7)	**685.9**
12								
13	**Cost of Sales**		**-**	**(429.5)**	**429.5**	**-**		
14							-	
15			-	(429.5)	429.5	-	-	**-**
16								
17	**Fuel**		**4.9**	**-**	**0.0**	**4.9**		
18								
19	Reclassification of Carbon Tax from O&M						0.6	
20								
21		Sch 1	4.9	-	0.0	4.9	0.6	**5.5**
22								
23								
24	**Operating and Maintenance**		**373.2**	**(0.4)**	**192.2**	**181.4**		
25								
26	Negative Salvage (Net Dismantling Costs) Reclass to Depreciation						(14.6)	
27	Non-recovered (Disallowed) Utility Costs						(6.7)	
28	Farms Reclassification						(3.8)	
29	Reclassification of Credit Facility fees from Financing						0.9	
30	Elimination of Non-Regulated Costs						(1.8)	
31	Reclassification of Carbon Tax to Fuel						(0.6)	
32	Other						5.5	
33								
34								
35		Sch 1	373.2	(0.4)	192.2	181.4	(21.2)	**160.2**
36								

ATCO Electric Transmission (AET)

RECONCILIATION OF FINANCIAL REPORTING SCHEDULES TO AUDITED FINANCIAL STATEMENTS (TRANSMISSION & DISTRIBUTION)

FOR THE YEAR ENDED DECEMBER 31, 2019

INCOME STATEMENT ITEMS

($Millions)

Line No.	Description	Cross-Reference	Audited Financial Statements	Intercompany Eliminations	Distribution Financial Statements	Transmission Financial Statements	Transmission Utility Adjustments	Transmission Utility Total
37	**Depreciation and Amortization**		**286.5**	**(8.2)**	**115.1**	**179.6**		
38								
39	Negative Salvage (Net Dismantling Costs) Reclass to Depreciation						31.6	
40	Reclass of Amortization of Contributions to Depreciation						(11.0)	
41	Reclass of Amortization of Cancelled Project Contribution						(14.5)	
42	Farms Reclassification						1.3	
43	Non-Utility Depreciation						(0.2)	
44	Other						1.6	
45								
46		Sch 1	286.5	(8.2)	115.1	179.6	8.8	**188.5**
47								
48	**Income Tax**		**(40.2)**	**(1.3)**	**(7.7)**	**(31.2)**		
49	Tax on Adjustments	Note 2					69.7	
50		Sch 1	(40.2)	(1.3)	(7.7)	(31.2)	69.7	**38.5**
51								
52	**Revenue Offsets**							
53								
54	Reclassification of Revenue Offsets						26.8	
55								
56		Sch 1	-	-	-	-	26.8	**26.8**
57								
58	**Return**		**663.7**	**(3.7)**	**246.5**	**420.8**		
59	Adjustments	Note 1					(100.9)	
60		Sch 1	663.7	(3.7)	246.5	420.8	(100.9)	**320.0**
61								
62	**Note 1 - Return Adjustments**							
63	Long Term Debt & Other		**216.8**	**-**	**66.7**	**150.1**		
64	Adjustment for IFRS IDC Treatment						4.0	
65	Credit facility Reclass to O&M						(0.9)	
66	Financing Other						(8.3)	
67			216.8	-	66.7	150.1	(5.1)	**145.0**
68								
69	Preferred Shares		**-**	**-**	**-**	**-**		
70							3.5	
71			-	-	-	-	3.5	**3.5**
72								
73	Return on Equity		**446.9**	**(3.7)**	**179.9**	**270.7**		
74		Note 2					(99.2)	
75			446.9	(3.7)	179.9	270.7	(99.2)	**171.6**
76								
77	**Total Return Adjustments**		**663.7**	**(3.7)**	**246.5**	**420.8**	**(100.8)**	**320.0**
78								

ATCO Electric Transmission (AET)

RECONCILIATION OF FINANCIAL REPORTING SCHEDULES TO AUDITED FINANCIAL STATEMENTS (TRANSMISSION & DISTRIBUTION)

FOR THE YEAR ENDED DECEMBER 31, 2019
INCOME STATEMENT ITEMS
($Millions)

Line No.	Description	Cross-Reference	Audited Financial Statements	Intercompany Eliminations	Distribution Financial Statements	Transmission Financial Statements	Transmission Utility Adjustments	Transmission Utility Total
79							**(Return)**	
80	**Note 2 - Return on Equity Adjustments**					Before tax	After tax	**Tax impact**
81								
82	**Financing & Subs**							
83	Preferred Dividends					(3.5)	(3.5)	**-**
84	IDC					(4.0)	(3.0)	**(1.1)**
85	Interest and Other					9.2	6.7	**2.4**
86								
87	**Income Tax**							
88	Income Tax (Provincial Future Tax for IFRS)						13.6	**(13.6)**
89	Income Tax (T2S1 Additions & Deductions Non Regulatory)						3.5	**(3.5)**
90	Income Tax (T2S1 Additions & Deductions Non IFRS)						(4.3)	**4.3**
91	Income Tax (Provincial Income Tax Rate Change)						(88.2)	**88.2**
92	Income Tax (T2S1 Other)						(1.2)	**1.2**
93								
94	**Other Income Statement Items**							
95	Revenue Tax Impact					(42.9)	(31.5)	**(11.4)**
96	O&M Tax Impact					(20.5)	15.1	**5.4**
97	Depreciation Tax Impact					8.8	(6.5)	**(2.3)**
98								
99						(52.9)	(99.2)	**69.7**

ATCO Electric Transmission (AET)

RECONCILIATION OF FINANCIAL REPORTING SCHEDULES TO AUDITED FINANCIAL STATEMENTS
(Transmission and Distribution)
FOR THE YEAR ENDED DECEMBER 31, 2019
BALANCE SHEET ITEMS
($Millions)

Line No.		Description	Cross-Reference	Audited Financial Statements (see attached)	Adjustments	Total
1	**Assets**					
2		**Current Assets**				
3		Cash and short term investments		36.7	-	36.7
5		Accounts receivable		145.5	-	145.5
6		Income taxes		1.0	655.7	656.7
7		Inventories		3.9	-	3.9
8		Prepaid expenses		6.4	-	6.4
10						
11		**Property, plant and equipment**		9,439.1	(799.6)	8,639.5
12		**Intangibles**		324.4	3.8	328.2
13						
14		**Investments**		125.6	(25.2)	100.4
15						
16		**Regulatory Assets**		-	57.0	57.0
17		**Deferred financing Charges**		-	27.7	27.7
18		**Other**		-	-	-
19						
20		**Total Assets**		**10,082.5**	**(80.7)**	**10,001.9**
21						
22						
23	**Liabilities**					
24		**Current Liabilities**				
25		Bank Indebtedness		-	-	-
26		Short term advances from parent and affiliated corporations		15.0	-	15.0
27		Accounts payable and accrued liabilities		119.1	-	119.1
28		Owing to parent and affiliated corporations		67.2	-	67.2
29		Income taxes payable		-	0.0	0.0
30		Regulatory Liabilities		-	-	-
31		Long term debt		38.2	38.2	76.5
32						
33		**Future income taxes**		815.2	(3.0)	812.2
34		**Regulatory Liabilities**		-	-	-
35		**Long term debt**		4,970.6	(800.1)	4,170.6
36		**Other**		1,050.7	(1,312.0)	(261.3)
37						
38		**Total Liabilities**		**7,076.0**	**(2,076.8)**	**4,999.2**
39						
40	**Equity**					
41		Equity preferred shares to Parent Corporation		142.0	-	142.0
42						
43		**Class A and Class B shares owner's equity**				
44		Class A and Class B shares		1,212.4	-	1,212.4
45		Retained earnings		1,652.1	1,996.2	3,648.3
46		Non-controlling interest		-	-	-
47		**Total Equity**		**3,006.5**	**1,996.2**	**5,002.7**
48						
49		**Total Liabilities and Share Owner's Equity**		**10,082.5**	**(80.7)**	**10,001.9**

ATCO ELECTRIC LTD.

NON-CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2019

Independent auditor's report

To the Shareowner of ATCO Electric Ltd.

Our opinion

In our opinion, the accompanying non-consolidated financial statements present fairly, in all material respects, the financial position of ATCO Electric Ltd. (the Company) as at December 31, 2019 and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board (IFRS).

What we have audited

The Company's non-consolidated financial statements comprise:

- the non-consolidated statement of earnings for the year ended December 31, 2019;
- the non-consolidated statement of comprehensive income for the year ended December 31, 2019;
- the non-consolidated balance sheet as at December 31, 2019;
- the non-consolidated statement of changes in equity for the year ended December 31, 2019;
- the non-consolidated statement of cash flow for the year ended December 31, 2019; and
- the notes to the non-consolidated financial statements, which include a summary of significant accounting policies.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the non-consolidated financial statements* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence

We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the non-consolidated financial statements in Canada. We have fulfilled our other ethical responsibilities in accordance with these requirements.

PricewaterhouseCoopers LLP
Stantec Tower, 10220 103 Avenue NW, Suite 2200, Edmonton, Alberta, Canada T5J 0K4
T: +1 780 441 6700, F: +1 780 441 6776

Responsibilities of management and those charged with governance for the non-consolidated financial statements

Management is responsible for the preparation and fair presentation of the non-consolidated financial statements in accordance with IFRS, and for such internal control as management determines is necessary to enable the preparation of non-consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the non-consolidated financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's responsibilities for the audit of the non-consolidated financial statements

Our objectives are to obtain reasonable assurance about whether the non-consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these non-consolidated financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the non-consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern.

If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the non-consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the non-consolidated financial statements, including the disclosures, and whether the non-consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

PricewaterhouseCoopers LLP

Chartered Professional Accountants

Edmonton, Alberta
May 4, 2020

TABLE OF CONTENTS

	Page
Non-consolidated Statement of Earnings	2
Non-consolidated Statement of Comprehensive Income	3
Non-consolidated Balance Sheet	4
Non-consolidated Statement of Changes in Equity	5
Non-consolidated Statement of Cash Flow	6
Notes to Non-consolidated Financial Statements	
General Information	
1. The Company and its Operations	7
2. Basis of Presentation	7
3. Change in Accounting Policies	8
Information on Financial Performance	
4. Adjusted Earnings	8
5. Revenues	12
6. Other Costs and Expenses	12
7. Interest Expense	12
8. Income Taxes	12
Information on Financial Position	
9. Property, Plant and Equipment	14
10. Intangibles	15
11. Investments	15
12. Long-Term Debt	16
13. Retirement Benefits	16
14. Balances from Contracts with Customers	17
15. Equity Preferred Shares	19
16. Class A and Class B Shares	20
Information on Cash Flow	
17. Cash Flow Information	20
Risk	
18. Financial Instruments	21
19. Risk Management	22
20. Capital Disclosures	23
21. Significant Judgments, Estimates and Assumptions	24
Other Information	
22. Contingencies	25
23. Commitments	25
24. Related Party Transactions	26
25. Subsequent Events	28
26 Accounting Policies	29

NON-CONSOLIDATED STATEMENT OF EARNINGS

(thousands of Canadian Dollars)	Note	Year Ended December 31 2019	2018
Revenues	5	**1,288,116**	1,190,131
Costs and expenses			
Salaries, wages and benefits		**(78,852)**	(113,023)
Plant and equipment maintenance		**(86,013)**	(61,618)
Fuel costs		**(4,893)**	(7,093)
Depreciation and amortization	9,10	**(286,547)**	(302,944)
Franchise fees		**(30,879)**	(22,501)
Property and other taxes		**(47,933)**	(54,027)
Other	6	**(129,512)**	(124,086)
		(664,629)	(685,292)
Dividend income from subsidiary companies	11	**8,725**	7,038
Operating profit		**632,212**	511,877
Interest income		**5,429**	6,400
Interest expense	7	**(230,948)**	(225,277)
Net finance costs		**(225,519)**	(218,877)
Earnings before income taxes		**406,693**	293,000
Income tax recovery (expense)	8	**40,211**	(77,601)
Earnings for the year		**446,904**	215,399

See accompanying Notes to Non-consolidated Financial Statements.

NON-CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

		Year Ended December 31	
(thousands of Canadian Dollars)	**Note**	**2019**	**2018**
Earnings for the year		**446,904**	215,399
Other comprehensive (loss) income, net of income taxes			
Items that will not be reclassified to earnings:			
Re-measurement of retirement benefits [1]	13	**(3,564)**	1,562
Comprehensive income for the year		**443,340**	216,961

(1) Net of income taxes of $1 million for the year ended December 31, 2019 (2018 - $(0.6) million).

See accompanying Notes to Non-consolidated Financial Statements.

NON-CONSOLIDATED BALANCE SHEET

(thousands of Canadian Dollars)	Note	December 31 2019	2018
ASSETS			
Current assets			
Cash		**1,172**	10,916
Short-term advances to parent company	24	**34,000**	1,300
Accounts receivable and contract assets	14	**139,173**	154,041
Accounts receivable from parent and affiliate companies	14, 24	**6,322**	19,642
Inventories		**3,885**	2,548
Income taxes recoverable		**1,025**	996
Prepaid expenses and other current assets		**6,386**	6,888
Advances to subsidiary companies	24	**1,500**	12,250
		193,463	208,581
Non-current assets			
Property, plant and equipment	9	**9,439,051**	9,341,506
Intangibles	10	**324,397**	325,311
Investment in subsidiary companies	11	**16,335**	16,335
Long-term advances to subsidiary companies	24	**99,823**	91,413
Other assets		**9,467**	9,249
Total assets		**10,082,536**	9,992,395
LIABILITIES			
Current liabilities			
Bank indebtedness		–	178
Short-term advances from parent and affiliated companies	24	**15,000**	54,300
Accounts payable and accrued liabilities		**118,601**	115,700
Accounts payable to parent and affiliate companies	24	**67,178**	68,244
Other provisions		–	7,933
Long-term debt	12	**38,243**	132,044
Other current liabilities		**479**	232
		239,501	378,631
Non-current liabilities			
Deferred income tax liabilities	8	**815,209**	858,651
Retirement benefit obligations	13	**59,369**	56,348
Deferred revenues	14	**991,067**	987,661
Long-term debt	12	**4,970,637**	4,876,233
Other liabilities		**240**	–
Total liabilities		**7,076,023**	7,157,524
EQUITY			
Equity preferred shares	15	**141,968**	141,968
Class A and Class B share owner's equity			
Class A and Class B shares	16	**1,212,428**	1,212,428
Retained earnings		**1,652,117**	1,480,475
		2,864,545	2,692,903
Total equity		**3,006,513**	2,834,871
Total liabilities and equity		**10,082,536**	9,992,395

See accompanying Notes to Non-consolidated Financial Statements.

DIRECTOR

DIRECTOR

NON-CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(thousands of Canadian Dollars)	**Note**	**Class A and Class B Shares**	**Equity Preferred Shares**	**Retained Earnings**	**Accumulated Other Comprehensive Income**	**Total Equity**
December 31, 2017		1,212,428	141,968	1,529,206	–	2,883,602
Earnings for the year		–	–	215,399	–	215,399
Other comprehensive income		–	–	–	1,562	1,562
Gains on retirement benefits transferred to retained earnings	13	–	–	1,562	(1,562)	–
Dividends	15,16	–	–	(265,692)	–	(265,692)
December 31, 2018		1,212,428	141,968	1,480,475	–	2,834,871
Earnings for the year		–	–	**446,904**	–	**446,904**
Other comprehensive loss		–	–	–	**(3,564)**	**(3,564)**
Loss on retirement benefits transferred to retained earnings	13	–	–	**(3,564)**	**3,564**	–
Dividends	15,16	–	–	**(271,698)**	–	**(271,698)**
December 31, 2019		**1,212,428**	**141,968**	**1,652,117**	–	**3,006,513**

See accompanying Notes to Non-consolidated Financial Statements.

NON-CONSOLIDATED STATEMENT OF CASH FLOW

(thousands of Canadian Dollars)	Note	Year Ended December 31 2019	2018
Operating activities			
Earnings for the year		**446,904**	215,399
Adjustments to reconcile earnings to cash flows from operating activities	17	**456,735**	600,632
Changes in non-cash working capital	17	**28,073**	(18,740)
Cash flows from operating activities		**931,712**	797,291
Investing activities			
Additions to property, plant and equipment		**(341,869)**	(406,646)
Proceeds on disposal of property, plant and equipment		**(55)**	700
Additions to intangibles	10	**(25,517)**	(37,913)
Changes in non-cash working capital	17	**(3,183)**	(17,544)
Other		**255**	(221)
Cash flows used in investing activities		**(370,369)**	(461,624)
Financing activities			
Issue of long-term debt	12	**122,835**	134,150
Repayment of long-term debt		**(119,794)**	–
Repayment of lease liability		**(941)**	–
Dividends paid on equity preferred shares		**(5,692)**	(5,692)
Dividends paid to Class A and Class B share owner		**(266,000)**	(260,000)
Interest paid		**(228,230)**	(224,796)
Other		**(1,087)**	(972)
Cash flows used in financing activities		**(498,909)**	(357,310)
Increase (decrease) in cash position		**62,434**	(21,643)
Beginning of year		**(42,262)**	(20,619)
End of year	17	**20,172**	(42,262)

See accompanying Notes to Non-consolidated Financial Statements.

NOTES TO NON-CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2019

(Tabular amounts in thousands of Canadian Dollars, except as otherwise noted)

1. THE COMPANY AND ITS OPERATIONS

ATCO Electric is engaged in the transmission and distribution of electric energy in the Province of Alberta. Its registered office and head office is at 19th Floor, 10035 -105 Street NW, Edmonton, Alberta, T5J 2V6. ATCO Electric is principally owned by CU Inc. which is controlled by Canadian Utilities Limited, which in turn is principally controlled by ATCO Ltd. and its controlling share owner, the Southern family.

In these non-consolidated financial statements, "the Company" means ATCO Electric Ltd.

2. BASIS OF PRESENTATION

STATEMENT OF COMPLIANCE

The non-consolidated financial statements are prepared according to International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB) and interpretations of the IFRS Interpretations Committee (IFRIC).

Pursuant to the Company's regulatory obligation to the Alberta Utilities Commission (AUC) and interested parties, the Company is obliged to provide detailed information relating solely to the electric utility and not relating to non-regulated subsidiaries, nor electric utilities regulated by other jurisdictions. The Company has, therefore, exercised the exemption from full consolidation of its investment in subsidiary companies available under IAS 27 *Separate Financial Statements*. As a result, the Company's investment in subsidiary companies and joint arrangements are carried at the original cost and the earnings of the subsidiary companies are reflected in the determination of earnings of the Company only to the extent of dividends received from the subsidiaries. The Company's proportionate interest in balances and transactions of joint arrangements have been excluded from these non-consolidated financial statements. Consolidated financial statements of the Company's immediate parent, CU Inc., that comply with IFRS are available for public use. CU Inc. is incorporated in Canada and its registered office is at 4th Floor, West Building, 5302 Forand Street SW, Calgary, Alberta T3E 8B4.

Management authorized these non-consolidated financial statements for issue on April 29, 2020.

BASIS OF MEASUREMENT

The non-consolidated financial statements are prepared on a historic cost basis, except for retirement benefit obligations and cash-settled share-based compensation liabilities which are carried at remeasured amounts or fair value. The Company's significant accounting policies are described in Note 25.

Certain comparative figures have been reclassified to conform to the current presentation.

FUNCTIONAL AND PRESENTATION CURRENCY

The non-consolidated financial statements are presented in Canadian dollars, which is the Company's functional currency.

USE OF ESTIMATES AND JUDGMENTS

Management makes estimates and judgments that could significantly affect how policies are applied, amounts in the non-consolidated financial statements are reported, and contingent assets and liabilities are disclosed. Most often these estimates and judgments concern matters that are inherently complex and uncertain. Estimates and judgments are reviewed on an on-going basis; changes to accounting estimates are recognized prospectively. The significant judgments, estimates and assumptions are described in Note 21.

3. CHANGE IN ACCOUNTING POLICIES

LEASES

The Company adopted IFRS 16 *Leases* on January 1, 2019, which introduces a new approach to lease accounting. The Company adopted the standard using the modified retrospective approach, which does not require restatement of prior year financial information, as it recognizes the cumulative impact on the opening balance sheet and applies the standard prospectively. Accordingly, the comparative information in these non-consolidated financial statements has not been restated.

At the inception of a contract, the Company assesses whether the contract is, or contains, a lease based on whether the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. This policy is applied to contracts in existence at January 1, 2019, and is applied to contracts entered into, or modified, on or after January 1, 2019.

Practical expedients

Effective January 1, 2019, the IFRS 16 transition date, the Company elected to use the following practical expedients under the modified retrospective transition approach:

- Leases with lease terms of less than twelve months (short-term leases) and leases of low-value assets (less than $5,000 U.S. dollars) (low-value leases) that have been identified at transition, were not recognized in the non-consolidated balance sheet;
- Right-of-use assets on transition were measured at the amount equal to the lease liabilities at transition, adjusted by the amount of any prepaid or accrued lease payments;
- For certain leases having associated initial direct costs, the Company, at initial measurement on transition, excluded these directs costs from the measurement of the right-of-use assets; and
- Any provision for onerous lease contracts previously recognized at the date of adoption of IFRS 16, has been applied to the associated right-of-use asset recognized upon transition.

The Company's non-consolidated financial statements were not impacted by the adoption of IFRS 16 *Leases* in relation to lessor accounting. Lessors will continue with the dual classification model for recognized leases with the resultant accounting remaining unchanged from IAS 17 *Leases.*

IMPACT OF CHANGES IN ACCOUNTING POLICIES

There was no material impact on the non-consolidated statement of earnings, balance sheet, statement of changes in equity and statement of cash flow resulting from the adoption of IFRS 16 noted above.

4. ADJUSTED EARNINGS

ADJUSTED EARNINGS

Adjusted earnings are earnings for the year after adjusting for:

- the timing of revenues and expenses for rate-regulated activities,
- dividends on equity preferred shares,
- one-time gains and losses,
- significant impairments, and
- items that are not in the normal course of business or a result of day-to-day operations.

Adjusted earnings are a key measure of earnings used by the Chief Operating Decision Maker (CODM) to assess performance and allocate resources. Other accounts in the non-consolidated financial statements have not been adjusted as they are not used by the CODM for those purposes.

The reconciliation of adjusted earnings and earnings for the year ended December 31 is shown below.

	2019	2018
Adjusted earnings	**329,044**	287,075
Restructuring costs	**–**	(25,015)
Gain (loss) on sale of assets	**(2,335)**	–
Rate-regulated activities	**125,641**	(52,353)
IT Common Matters decision	**(11,138)**	–
Dividends on equity preferred shares	**5,692**	5,692
Earnings for the year	**446,904**	215,399

Restructuring and other costs

In 2018, the Company recorded restructuring and other costs of $25 million, after-tax, that were not in the normal course of business. These costs mainly related to staff reductions and associated severance costs.

Rate-regulated activities

There is currently no specific guidance under IFRS for rate-regulated entities that the Company is eligible to adopt. In the absence of this guidance, the utilities do not recognize assets and liabilities from rate-regulated activities as may be directed by regulatory decisions. Instead, the utilities recognize revenues in earnings when amounts are billed to customers, consistent with the regulator-approved rate design. Operating costs and expenses are recorded when incurred. Costs incurred in constructing an asset that meet the asset recognition criteria are included in the related property, plant and equipment or intangible asset.

The Company uses standards issued by the Financial Accounting Standards Board (FASB) in the United States as another source of generally accepted accounting principles to account for rate-regulated activities in its internal reporting provided to the CODM. The CODM believes that earnings presented in accordance with the FASB standards are a better representation of the operating results of the Company’s rate-regulated activities. Therefore, the Company presents adjusted earnings as part of its segmented disclosures on this basis. Rate-regulated accounting (RRA) standards impact the timing of how certain revenues and expenses are recognized when compared to non-rate regulated activities, to appropriately reflect the economic impact of a regulators' decisions on revenues.

Rate-regulated accounting differs from IFRS in the following ways:

	Timing Adjustment	Items	RRA Treatment	IFRS Treatment
1.	Additional revenues billed in current period	Future removal and site restoration costs.	The Company defers the recognition of cash received in advance of future expenditures.	The Company recognizes revenues when amounts are billed to customers and costs when they are incurred.
2.	Revenues to be billed in future periods	Deferred income taxes.	The Company recognizes revenues associated with recoverable costs in advance of future billings to customers.	The Company recognizes costs when they are incurred, but does not recognize their recovery until customer rates are changed and amounts are collected through future billings.
3.	Regulatory decisions received	Regulatory decisions received which relate to current and prior periods.	The Company recognizes the earnings from a regulatory decision pertaining to current and prior periods when the decision is received.	The Company does not recognize earnings from a regulatory decision when it is received as regulatory assets and liabilities are not recorded under IFRS.
4.	Settlement of regulatory decisions and other items	Settlement of amounts receivable or payable to customers and other items.	The Company recognizes the amount receivable or payable to customers as a reduction in its regulatory assets and liabilities when collected or refunded through future billings.	The Company recognizes earnings when customer rates are changed and amounts are recovered or refunded to customers through future billings.

At December 31, the significant timing adjustments as a result of the differences between rate-regulated accounting and IFRS are as follows:

	2019	2018
Additional revenues billed in current period		
Future removal and site restoration costs (1)	**25,277**	34,809
Revenues to be billed in future periods		
Deferred income taxes (2)	**96,954**	(48,142)
Regulatory decisions received	**(5,412)**	2,034
Settlement of decisions and other items (3)	**8,822**	(41,054)
	125,641	(52,353)

(1) Removal and site restoration costs are billed to customers over the estimated useful life of the related assets based on forecast costs to be incurred in future periods.

(2) Income taxes are billed to customers when paid by the Company.

(3) In 2018, the Company recorded a decrease in earnings of $38 million mainly related to a refund of deferral account balances relating to 2013 and 2014.

Regulatory decisions received

Under rate-regulated accounting, the Company recognizes earnings from a regulatory decision pertaining to current and prior periods when the decision is received. The significant regulatory decisions impacting adjusted earnings during 2019 are provided below.

	Decision	Amount	Description
1.	Information Technology (IT) Common Matters	11,138	In August 2014, the Canadian Utilities sold its IT services business to Wipro Ltd. (Wipro) and signed a ten-year IT Master Services Agreement (MSA) effective January 1, 2015. In 2015, the Alberta Utilities Commission (AUC) commenced an Information Technology Common Matters proceeding to review the recovery of IT costs by the Alberta Utilities from January 1, 2015 going forward. On June 5, 2019, the AUC issued its decision regarding the IT Common Matters proceeding and directed the Company to reduce the first-year of the Wipro MSA by 13 per cent and to apply a glide path that reduces pricing by 4.61 per cent in each of years 2 through 10. The reduction in adjusted earnings resulting from the decision for the period January 1, 2015 to December 31, 2019 was $11 million. Of this amount, $7 million relates to the period January 1, 2015 to June 30, 2019 and was recorded in the second quarter of 2019. The remaining $4 million was recorded in the second half of 2019.
2.	ATCO Electric General Tariff Application (GTA) Compliance Filing	(16,550)	In June 2017, the Company' filed a GTA for its electric transmission operations for 2018 and 2019. An AUC decision was issued in July 2019 approving the majority of capital expenditures and operating costs requested. The increase in adjusted earnings resulting from the decision was $17 million, of which $9 million relates to 2018.

IT Common Matters decision

As described in the IT Common Matters decision above, in August 2014, Canadian Utilities sold its IT services business to Wipro Ltd. (Wipro) and signed a ten-year IT Master Services Agreement (MSA) effective January 1, 2015. Proceeds of the sale were $204 million, resulting in a one-time after-tax gain of $138 million. In 2014, Canadian Utilities did not include this gain on sale in adjusted earnings because it was a significant one-time event.

In June 2019, the AUC issued its decision regarding the IT Common Matters proceeding which is described in the regulatory decisions received section above. In the proceeding, the Alberta Utilities presented a considerable amount of evidence, including expert benchmarking and price review studies, to support that the Wipro MSA rates were at fair market value. As such, there was no cross subsidization between the sale price of the Canadian Utilities' IT services business to Wipro in the 2014 transaction and the establishment of IT rates under the MSA. Despite these efforts the AUC found that the Alberta Utilities failed to demonstrate that the IT pricing in the MSA would result in just and reasonable rates.

Consistent with the treatment in 2014, the $11.1 million reduction recognized in 2019, along with future impacts associated with this decision, will be excluded from adjusted earnings.

5. REVENUES

The significant categories of revenues recognized during the year are as follows:

	2019	2018
Distribution revenue	**461,239**	425,200
Transmission revenue	**673,817**	621,905
Customer contributions *(Note 14)*	**43,716**	29,579
Franchise fees & property tax revenues	**30,879**	29,177
Other	**78,465**	84,270
	1,288,116	1,190,131

6. OTHER COSTS AND EXPENSES

Other costs and expenses comprise the following:

	2019	2018
Professional fees, services and contractors	**11,636**	9,278
Technology expenses	**27,687**	22,161
Insurance	**5,761**	5,151
Travel and meals	**2,919**	1,942
Office services and other costs	**1,042**	661
Head office fees	**46,107**	42,904
Licenses	**7,796**	14,278
Corporate license fees	**5,026**	6,406
Loss on disposal	**3,699**	355
Telecommunications	**1,844**	1,270
Other	**15,995**	19,680
	129,512	124,086

7. INTEREST EXPENSE

Interest expense primarily arises from interest on long-term debentures. The components of interest expense are summarized below.

	2019	2018
Long-term debt	**231,422**	230,271
Amortization of deferred financing charges	**984**	868
Other	**4,420**	4,411
	236,826	235,550
Less: interest capitalized *(Note 9)*	**(5,878)**	(10,273)
	230,948	225,277

Borrowing costs capitalized to property, plant and equipment during 2019 were calculated by applying a weighted average interest rate of 4.58 per cent (2018 - 4.68 per cent).

8. INCOME TAXES

IMPACT OF CHANGE IN INCOME TAX RATE

In May 2019, the Alberta government passed Bill 3, the Job Creation Tax Cut, which will reduce the Alberta provincial corporate tax rate from 12 per cent to 8 per cent in a phased approach between July 1, 2019 and January 1, 2022.

As a result of this change the Company made an adjustment in 2019 to deferred income taxes of $139 million.

As the tax rate change came into effect on July 1, 2019, the combined federal and Alberta statutory Canadian income tax rate for 2019 is 26.5 per cent. Prior to the change, the combined federal and Alberta statutory Canadian income tax rate for 2019 was 27.0 per cent.

INCOME TAX EXPENSE

The components of income tax expense are summarized below.

	2019	2018
Current income tax expense		
Expenses for the year	**2,258**	2,276
Adjustment in respect of prior years	**(19)**	(26)
	2,239	2,250
Deferred income tax expense		
Reversal of temporary differences	**97,186**	75,290
Change in income taxes resulting from decrease in provincial corporate tax rate	**(139,264)**	–
Adjustment in respect of prior years	**(372)**	61
	(42,450)	75,351
	(40,211)	77,601

The reconciliation of statutory and effective income tax expense is as follows:

	2019		2018	
Earnings before income taxes	**406,693**	**%**	293,000	%
Income taxes, at statutory rates	**107,774**	**26.5**	79,110	27.0
Dividend income	**(2,451)**	**(0.6)**	(1,900)	(0.6)
Part VI.I tax net of transfer benefit	**165**	–	124	–
Change in income taxes resulting from decrease in provincial corporate tax rate	**(139,264)**	**(34.2)**	–	–
Statutory and deferred tax variance	**(6,000)**	**(1.5)**	–	–
Other	**(435)**	**(0.1)**	267	0.1
	(40,211)	**(9.9)**	77,601	26.5

DEFERRED INCOME TAXES

The changes in deferred income tax liabilities are as follows:

	Property, Plant and Equipment	Intangibles	Tax Loss Carry Forwards and Tax Credits	Retirement Benefit Obligations and Other	Total
December 31, 2017	780,623	53,585	(70,022)	18,536	782,722
Charge (credit) to earnings	108,270	2,634	(4,723)	(30,830)	75,351
Charge to other comprehensive income	–	–	–	578	578
December 31, 2018	888,893	56,219	(74,745)	(11,716)	858,651
Charge (credit) to earnings	**79,013**	**(2,393)**	**16,719**	**3,475**	**96,814**
Credit to other comprehensive income	–	–	–	**(986)**	**(986)**
Change in income taxes resulting from decrease in provincial corporate tax rate	**(136,994)**	**(8,521)**	**4,177**	**2,074**	**(139,264)**
Other	–	–	–	**(6)**	**(6)**
December 31, 2019	**830,912**	**45,305**	**(53,849)**	**(7,159)**	**815,209**

The Company does not expect its deferred income tax liabilities to reverse within the next twelve months (2018 - nil).

At December 31, 2019, the Company had $215 million of non-capital tax losses and credits which expire between 2034 and 2037. The Company recognized deferred income tax assets of $54 million for these losses and credits.

9. PROPERTY, PLANT AND EQUIPMENT

A reconciliation of the changes in the carrying amount of property, plant and equipment is as follows:

	Utility Transmission & Distribution	Land and Buildings	Construction Work-in-Progress	Other	Total
Cost					
December 31, 2017	10,247,719	406,650	289,203	537,637	11,481,209
Additions	2,101	–	421,864	–	423,965
Transfers	396,826	5,731	(418,153)	15,596	–
Retirements and disposals	(32,751)	(1,730)	–	(12,104)	(46,585)
Transfer to affiliate companies	–	1,365	–	(266)	1,099
December 31, 2018	10,613,895	412,016	292,914	540,863	11,859,688
Additions	–	–	**369,663**	–	**369,663**
Transfers	**448,053**	**5,404**	**(463,006)**	**9,549**	–
Retirements and disposals	**(41,293)**	**(8,160)**	**(14,523)**	**(8,081)**	**(72,057)**
Transfer to affiliate companies	–	–	–	**(113)**	**(113)**
December 31, 2019	**11,020,655**	**409,260**	**185,048**	**542,218**	**12,157,181**
Accumulated depreciation					
December 31, 2017	2,023,143	62,150	–	200,211	2,285,504
Depreciation	234,358	11,759	–	29,429	275,546
Retirements and disposals	(29,599)	(1,042)	–	(12,089)	(42,730)
Transfer to affiliate companies	–	–	–	(138)	(138)
December 31, 2018	2,227,902	72,867	–	217,413	2,518,182
Depreciation	**209,156**	**12,153**	–	**36,286**	**257,595**
Retirements and disposals	**(41,293)**	**(8,160)**	–	**(8,137)**	**(57,590)**
Transfer to affiliate companies	–	–	–	**(57)**	**(57)**
December 31, 2019	**2,395,765**	**76,860**	–	**245,505**	**2,718,130**
Net book value					
December 31, 2018	8,385,993	339,149	292,914	323,450	9,341,506
December 31, 2019	**8,624,890**	**332,400**	**185,048**	**296,713**	**9,439,051**

The additions to property, plant and equipment included $5.9 million of interest capitalized during construction for the year ended December 31, 2019 (2018 - $10.3 million).

10. INTANGIBLES

Intangible assets consist mainly of computer software not directly attributable to the operation of property, plant and equipment and land rights. A reconciliation of the changes in the carrying amount of intangible assets is as follows:

	Computer Software	Land Rights	Total
Cost			
December 31, 2017	298,698	218,087	516,785
Additions	20,951	10,059	31,010
Retirements	(1,815)	–	(1,815)
December 31, 2018	317,834	228,146	545,980
Additions	**17,372**	**8,145**	**25,517**
Retirements	**(112,331)**	**(5)**	**(112,336)**
December 31, 2019	**222,875**	**236,286**	**459,161**
Accumulated amortization			
December 31, 2017	170,930	25,752	196,682
Amortization	22,482	3,320	25,802
Retirements	(1,815)	–	(1,815)
December 31, 2018	191,597	29,072	220,669
Amortization	**23,344**	**3,087**	**26,431**
Retirements	**(112,331)**	**(5)**	**(112,336)**
December 31, 2019	**102,610**	**32,154**	**134,764**
Net book value			
December 31, 2018	126,237	199,074	325,311
December 31, 2019	**120,265**	**204,132**	**324,397**

11. INVESTMENTS

The investment in subsidiary companies at December 31 is as follows:

Investee	Principal place of business	Percentage ownership	2019	2018
ATCO Electric Yukon	Whitehorse, Yukon	100%	**12,171**	12,171
Norven Holdings Inc.	Edmonton, Alberta	100%	**4,164**	4,164
			16,335	16,335

During 2019, the Company received $8.7 million in cash dividends from its subsidiaries (2018 - $7.0 million).

The Company has an 80% interest in ATCO-Valard Design Build Joint Venture. ATCO-Valard Design Build Joint Venture is an unincorporated joint arrangement between the Company and Valard Construction LP, a subsidiary of Quanta Services, Inc., for the purpose of developing, designing and building the Fort McMurray West 500-kilovolt (kV) Transmission Project.

12. LONG-TERM DEBT

Long-term debt outstanding at December 31 is as follows:

	Effective Interest Rate	2019	2018
Debentures - unsecured	4.653% (2018 - 4.697%)	**5,030,887**	5,030,931
(interest is the average effective interest rate weighted by principal amounts outstanding)			
Other long-term obligation, due June 2021 - unsecured	3.950%	**5,645**	4,900
Less: deferred financing charges		**(27,652)**	(27,554)
		5,008,880	5,008,277
Less: amounts due within one year		**(38,243)**	(132,044)
		4,970,637	4,876,233

Debenture Issuances

During 2019, the Company issued $132.0 million of 2.963 per cent debentures maturing on September 7, 2049 (2018 - $135.0 million of 3.95 per cent debentures maturing on November 23, 2048).

During 2019, the Company repaid $58.5 million of 5.432 per cent debentures and $73.5 million of 6.8 per cent debentures.

13. RETIREMENT BENEFITS

The Company, together with Canadian Utilities Limited and its subsidiary companies, maintains registered defined benefit and defined contribution pension plans for most of its employees and non-funded defined benefit pension plans for certain officers and key employees. It also provides other post-employment benefits, principally health, dental and life insurance, for retirees and their dependents. The defined benefit pension plans provide for pensions based on employees' length of service and final average earnings. As of 1997, new employees automatically participate in the defined contribution pension plan.

Information about the plans as a whole, in aggregate, can be found in the Canadian Utilities Limited consolidated financial statements for the year ended December 31, 2019.

Information about the Company's participation in the group benefit plans is as follows:

	2019		2018	
	Pension Benefit Plans	OPEB Plans	Pension Benefit Plans	OPEB Plans
Benefit plan cost				
Defined benefit plans cost	**7,188**	**1,894**	9,784	2,207
Defined contribution plans cost	**8,242**	–	9,601	–
Total cost	**15,430**	**1,894**	19,385	2,207
Less: capitalized	**10,304**	**1,259**	13,252	1,488
Net cost recognized	**5,126**	**635**	6,133	719
Accrued benefit obligations				
Beginning of year	21,875	34,473	22,586	34,945
Defined benefit plan cost	**7,188**	**1,894**	9,784	2,207
Benefit payments	**(2,920)**	**(1,211)**	(2,873)	(1,165)
Contributions to defined benefit plans	**(6,486)**	–	(6,995)	–
Actuarial losses (gains)	**2,179**	**2,377**	(627)	(1,514)
End of year	**21,836**	**37,533**	21,875	34,473

Weighted average assumptions

The significant assumptions used to determine the benefit plan cost and accrued benefit obligation were as follows:

	2019		2018	
	Pension Benefit Plans	**OPEB Plans**	**Pension Benefit Plans**	**OPEB Plans**
Benefit plan cost				
Discount rate for the year	**3.80%**	**3.80%**	3.60%	3.60%
Average compensation increase for the year	**2.50%**	**n/a**	2.50%	n/a
Accrued benefit obligations				
Discount rate at December 31	**3.10%**	**3.10%**	3.80%	3.80%
Long-term inflation rate	**2.00%**	**n/a**	2.00%	n/a
Health care cost trend rate:				
Drug costs (1)	**n/a**	**5.17%**	n/a	5.30%
Other medical costs	**n/a**	**4.00%**	n/a	4.50%
Dental costs	**n/a**	**4.00%**	n/a	4.00%

(1) The Company uses a graded drug cost trend rate which assumes a 5.17 per cent rate per annum, grading down to 4.00 per cent in and after 2040.

Defined benefit plan funding

An actuarial valuation for funding purposes as of December 31, 2017 was completed in 2018 for the registered defined benefit pension plans. The estimated contribution for 2020 is $6.7 million. The next actuarial valuation for funding purposes must be completed as of December 31, 2020.

14. BALANCES FROM CONTRACTS WITH CUSTOMERS

Balances from contracts with customers are comprised of trade accounts receivable and contract assets, trade accounts receivable from parent and affiliate companies and customer contributions.

ACCOUNTS RECEIVABLE AND CONTRACT ASSETS

At December 31, trade accounts receivable and contract assets are included in accounts receivable and contract assets:

	2019	2018
Trade accounts receivable and contract assets	**137,599**	151,185
Other accounts receivable	**1,574**	2,856
	139,173	154,041

At December 31, trade accounts receivable from parent and affiliate companies are included in accounts receivable from parent and affiliate companies:

	2019	2018
Trade accounts receivable from parent and affiliate companies	**5,326**	18,419
Other accounts receivable from parent and affiliate companies	**996**	1,223
	6,322	19,642

The significant changes in trade accounts receivable and contract assets are as follows:

	Trade accounts receivable and contract assets
December 31, 2017	119,247
Revenue from satisfied performance obligations	1,145,026
Payments received	(1,113,088)
December 31, 2018	151,185
Revenue from satisfied performance obligations	**1,197,933**
Credit loss allowance	**(723)**
Payments received	**(1,210,796)**
December 31, 2019	**137,599**

CUSTOMER CONTRIBUTIONS AND OTHER DEFERRED REVENUES

Certain additions to property, plant and equipment are made with the assistance of non-refundable cash contributions from customers. These contributions are made when the estimated revenue is less than the cost of providing service or where the customer needs special equipment. Since these contributions will provide customers with on-going access to the supply of electricity, they represent deferred revenues and are recognized in revenues over the life of the related asset.

Customer contributions and other deferred revenues at December 31 are as follows:

	2019	2018
Customer contributions	**978,467**	974,177
Other deferred revenues	**12,600**	13,484
	991,067	987,661

Changes in customer contributions balance are summarized below.

December 31, 2017	956,789
Receipt of customer contributions (*Note 17*)	46,967
Amortization (*Note 5*)	(29,579)
December 31, 2018	974,177
Receipt of customer contributions (*Note 17*)	**48,006**
Amortization (*Note 5*)	**(43,716)**
December 31, 2019	**978,467**

15. EQUITY PREFERRED SHARES

EQUITY PREFERRED SHARES TO CU INC.

Authorized and issued

Authorized: an unlimited number of Preferred Shares, issuable in series.

		2019		2018
Issued	**Shares**	**Amount**	**Shares**	**Amount**
Cumulative Redeemable Preferred Shares				
4.60% Series 1	**2,440,000**	**61,000**	2,440,000	61,000
2.243% Series 4	**1,560,000**	**39,000**	1,560,000	39,000
Issuance costs		**(1,702)**		(1,702)
		98,298		98,298

Rights and privileges

Preferred shares	Redemption Amount (1)	Quarterly Dividend (2)	Reset Premium (3)	Date Redeemable/ Convertible	Convertible To
Series 1	25.00	0.2875	Does not reset	Currently redeemable	Not convertible
Series 4	25.00	0.1401875	1.36%	June 1, 2021 (4)	Series 5 (5)

(1) Plus accrued and unpaid dividends.

(2) Cumulative, payable quarterly as and when declared by the Board.

(3) Dividend rate will reset on the date redeemable/convertible and every five years thereafter at a rate equal to the Government of Canada yield plus the reset premium noted.

(4) Redeemable by the Company or convertible by the holder on the date noted and every five years thereafter.

(5) If converted, holders will be entitled to receive quarterly floating rate dividends equal to the Government of Canada Treasury Bill yield plus the reset premium noted. Holders have the option to convert back to the original preferred shares series on subsequent redemption dates.

EQUITY PREFERRED SHARES TO CANADIAN UTILITIES LIMITED

Authorized and issued

Authorized: an unlimited number of Series Second Preferred Shares, issuable in series.

		2019		2018
Issued	**Shares**	**Amount**	**Shares**	**Amount**
Perpetual Cumulative Second Preferred Shares				
4.60% Series V	**1,748,578**	**43,714**	1,748,578	43,714
Issuance costs		**(44)**		(44)
		43,670		43,670

Rights and Privileges

The Series V Perpetual Cumulative Second Preferred Shares are redeemable at the option of the Company at the stated value plus accrued and unpaid dividends.

DIVIDENDS

Cash dividends declared and paid per share are as follows:

(dollars per share)	2019	2018
4.60% Series 1	**1.1500**	1.1500
2.243% Series 4	**0.5608**	0.5608
4.60% Series V	**1.1500**	1.1500

The payment of dividends is at the discretion of the Board and depends on the financial condition of the Company and other factors.

On January 9, 2020, the Company declared first quarter eligible dividends of $0.2875 per Series 1 Preferred Share and $0.1401875 per Series 4 Preferred Share.

16. CLASS A AND CLASS B SHARES

The number and dollar amount of outstanding Class A non-voting and Class B common shares at December 31, 2019 is shown below.

	Class A Non-Voting		Class B Common		Total	
	Shares	Amount	Shares	Amount	Shares	Amount
Authorized:	Unlimited		Unlimited			
Issued and outstanding:						
December 31, 2018 and 2019	**23,598,608**	**743,698**	**14,463,663**	**468,730**	**38,062,271**	**1,212,428**

Class A and B shares have no par value.

The Company declared and paid cash dividends of $6.99 per Class A non-voting share and Class B common share during 2019 (2018 - $6.83). The payment and amount of dividends is at the discretion of the Board and depends on the financial condition of the Company and other factors.

17. CASH FLOW INFORMATION

ADJUSTMENTS TO RECONCILE EARNINGS TO CASH FLOWS FROM OPERATING ACTIVITIES

Adjustments to reconcile earnings to cash flows from operating activities are summarized below.

	2019	2018
Depreciation and amortization	**286,547**	302,944
Income tax (recovery) expense	**(40,211)**	77,601
Contributions by utility customers for extensions to plant (*Note 14*)	**48,006**	46,967
Amortization of customer contributions (*Note 14*)	**(43,716)**	(29,579)
Net finance costs	**225,519**	218,877
Income taxes paid	**(2,287)**	(2,172)
Other	**(17,123)**	(14,006)
	456,735	600,632

CHANGES IN NON-CASH WORKING CAPITAL

The changes in non-cash working capital are summarized below.

	2019	2018
Operating activities		
Accounts receivable and contract assets	**10,907**	(32,880)
Accounts receivable to parent and affiliate companies	**13,066**	15,200
Inventories	**(1,338)**	(67)
Prepaid expenses and other current assets	**502**	3,715
Accounts payable and accrued liabilities	**3,974**	20,714
Accounts payable to parent and affiliate companies	**962**	(25,422)
	28,073	(18,740)
Investing activities		
Inventories	**1,717**	1,155
Accounts payable and accrued liabilities	**(8,994)**	(18,280)
Accounts receivable and contract assets	**4,094**	(419)
	(3,183)	(17,544)

CASH POSITION

Cash position in the non-consolidated statement of cash flows at December 31 is comprised of:

	2019	2018
Cash	**1,172**	10,916
Short-term advances to parent company	**34,000**	1,300
Bank indebtedness	**–**	(178)
Short-term advances from parent and affiliated companies	**(15,000)**	(54,300)
	20,172	(42,262)

18. FINANCIAL INSTRUMENTS

FAIR VALUE MEASUREMENT

Financial instruments are measured at amortized cost or fair value. Fair value represents the estimated amounts at which financial instruments could be exchanged between knowledgeable and willing parties in an arm's length transaction. Determining fair value requires management judgment. The valuation methods used to determine the fair value of each financial instrument and its associated level in the fair value hierarchy is described below.

Financial Instruments	Fair Value Method
Measured at Amortized Cost	
Cash, short-term advances to parent company, accounts receivable and contract assets, accounts receivable from parent and affiliate companies, bank indebtedness, short-term advances from parent and affiliated companies, accounts payable and accrued liabilities and accounts payable to parent and affiliate companies	Assumed to approximate carrying value due to their short-term nature.
Long-term debt	Determined using quoted market prices for the same or similar issues. Where the market prices are not available, fair values are estimated using discounted cash flow analysis based on the Company's current borrowing rate for similar borrowing arrangements (Level 2).

The fair values of the Company's financial instruments measured at amortized cost are as follows:

			2019		2018
Recurring Measurements	Note	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial Liabilities					
Long-term debt	12	**5,008,880**	**6,128,062**	5,008,277	5,439,510

OFFSETTING FINANCIAL ASSETS

The following financial assets are subject to offsetting, enforceable master netting arrangements and similar agreements:

			2019			2018
Financial Assets	Gross Amount	Gross Amount Offset	Net Amount Recognized	Gross Amount	Gross Amount Offset	Net Amount Recognized
Accounts receivable and contract assets	**58,959**	**(37,340)**	**21,619**	117,918	(76,021)	41,897

19. RISK MANAGEMENT

FINANCIAL RISKS

The Company is exposed to a variety of risks associated with the use of financial instruments: credit risk and liquidity risk. The Company's Board is responsible for understanding the principal risks of the Company's business, achieving a proper balance between risks incurred and the potential return to the share owner, and confirming there are controls in place to effectively monitor and manage those risks with a view to the long-term viability of the Company. The Board reviews significant risks associated with future performance, growth and lost opportunities identified by management that could materially affect the Company's ability to achieve its strategic or operational targets. The Board is also responsible for confirming that management has procedures in place to mitigate identified risks.

The source of risk exposure and how each is managed is outlined below.

CREDIT RISK

Credit risk is the risk of financial loss due to a counterparties inability to discharge their contractual obligations to the Company. The Company is exposed to credit risk on its cash and cash equivalents and accounts receivable and contract assets and accounts receivable from parent and affiliate companies. The exposure to credit risk represents the total carrying amount of these financial instruments in the non-consolidated balance sheet.

The company manages its credit risk on cash and cash equivalents by investing in instruments issued by credit-worthy financial institutions and in short-term instruments issued by the federal government.

The majority of the Company's accounts receivable and contract assets credit risk is reduced by financial security provided by Direct Energy and by retailers in accordance with provisions contained within the Electric Utilities Act Distribution Tariff Regulation A.R. 162/2003, and the Corporation's ability under the Regulation to recover through its distribution tariff any costs not recovered by a claim against such retailer security. At December 31, 2019, the Company held $102 million in letters of credit for certain counterparty receivables (2018 - $115 million).

Accounts receivable and contract assets are non-interest bearing and are generally due in 30 to 90 days. The provision for impairment of credit losses was $1 million in 2019 (2018 - less than $0.5 million). At December 31, 2019, the Company had $2.3 million of trade receivables past due greater than 30 days (2018 - $0.2 million). No other impairments have been identified within accounts receivable. The Company recorded a credit loss allowance of $0.7 million in 2019 in respect of trade receivables (2018 - nil).

The Company has also entered into guarantee arrangements with Centrica plc. relating to the retail energy supply functions performed by Direct Energy (see Note 22).

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations associated with its financial liabilities that are settled in cash or another financial asset. Liquidity risk arises from the Company's general funding needs and in the management of its assets, liabilities and capital structure. Cash flow from operations provides a substantial portion of the Company's cash requirements. Additional cash requirements are met with the use of existing cash balances, bank borrowings, obtaining advances from the parent company and issuance of long-term debt and Class A and B shares. Short term advances from the parent company provide flexibility in the timing and amounts of long term financing.

Lines of credit

At December 31, 2019, the Company has a line of credit of $10.0 million (2018 - $10.0 million). The credit line enables the Company to obtain financing for general business purposes. At December 31, 2019, $10.0 million of the credit line was available (2018 - $10.0 million).

Maturity analysis of financial obligations

The table below analyzes the remaining contractual maturities, of the Company's financial liabilities at December 31, 2019 based on the contractual undiscounted cash flows.

	2020	2021	2022	2023	2024	2025 and thereafter
Short-term advances from parent	15,000	–	–	–	–	–
Accounts payable and accrued liabilities	118,601	–	–	–	–	–
Accounts payable to parent and affiliate companies	67,178	–	–	–	–	–
Long-term debt:						
Principal	38,243	106,645	50,010	23,534	116,000	4,702,100
Interest expense	230,483	225,723	217,557	214,833	208,208	4,359,355
	469,505	332,368	267,567	238,367	324,208	9,061,455

20. CAPITAL DISCLOSURES

The Company's objective when managing capital is to remain within the capital structure approved by the AUC, which, through the generic cost of capital decisions established the capital structure for the Company. In August 2018, the Company received the 2018 generic cost of capital decision. The decision established the equity ratio for 2018, 2019 and 2020 at 37.0 per cent for transmission and distribution operations. The capitalization involves the use of long term debt and preferred share financings; the AUC approved the continued use of the latter in a decision issued in 2006.

The Company includes share owner's equity, preferred shares, and long term debt, as adjusted in accordance with the Financial Accounting Standards Board (FASB) standards (see Note 4 and 25), in its determination of capitalization. In maintaining or adjusting its capital structure, the Company may adjust the dividends paid to the share owner, issue or purchase Class A and Class B shares, and issue or redeem preferred shares, and long-term debt.

21. SIGNIFICANT JUDGMENTS, ESTIMATES AND ASSUMPTIONS

Significant judgments and estimates made by the Company are outlined below.

SIGNIFICANT ACCOUNTING JUDGMENTS

Impairment of long-lived assets

Indicators of impairment are considered when evaluating whether or not an asset is impaired. Factors which could indicate an impairment exists include: significant underperformance relative to historical or projected operating results, significant changes in the way in which an asset is used or in the Company's overall business strategy, significant negative industry or economic trends, or adverse decisions by the AUC. Events indicating an impairment may be clearly identifiable or based on an accumulation of individually insignificant events over a period of time. The Company continually monitors its operating facilities and the markets and business environment in which it operates. Judgments and assessments about conditions and events are made order to conclude whether a possible impairment exists.

Property, plant and equipment and intangibles

The Company makes judgments to: assess the nature of the costs to be capitalized and the time period over which they are capitalized in the purchase or construction of an asset; evaluate the appropriate level of componentization where an asset is made up of individual components for which different depreciation and amortization methods and useful lives are appropriate; distinguish major overhauls to be capitalized from repair and maintenance activities to be expensed; and determine the useful lives over which assets are depreciated and amortized.

Income taxes

The Company makes judgments with respect to changes in tax legislation, regulations and interpretations thereof. Judgment is also applied to estimating probable outcomes, when temporary differences will reverse, and whether tax assets are realizable.

SIGNIFICANT ACCOUNTING ESTIMATES AND ASSUMPTIONS

Revenue recognition

An estimate of usage not yet billed is included in revenues from the regulated distribution of electricity. The estimate is derived from unbilled electricity distribution services supplied to customers and is from the date of the last meter reading and uses historical consumption patterns. Management applies judgment to the measure and value of the estimated consumption.

Impairment of financial assets

The impairment loss allowance for financial assets are based on assumptions about risk of default and expected loss rates. For details regarding significant assumptions and key inputs used to calculate impairment loss allowance, see Note 19.

Useful lives of property, plant and equipment and intangibles

Useful lives are estimated based on current facts and past experience taking into account the anticipated physical life of the asset, existing long-term sales agreements and contracts, current and forecast demand, and the potential for technological obsolescence.

Impairment of long-lived assets

The Company continually monitors its long-lived assets and the markets and business environment in which it operates for indications of asset impairment. Where necessary, the Company estimates the recoverable amount for the cash generating unit (CGU) to determine if an impairment loss is to be recognized. These estimates are based on assumptions, such as the price for which the assets in the CGU could be obtained or future cash flows that will be produced by the CGU, discounted at an appropriate rate. Subsequent changes to these estimates or assumptions could significantly impact the carrying value of the assets in the CGU.

Retirement benefits

The Company consults with qualified actuaries when setting the assumptions used to estimate retirement benefit obligations and the cost of providing retirement benefits during the period. These assumptions reflect management's best estimates of the long-term inflation rate, projected salary increases, retirement age, discount rate, health care costs trend rates, life expectancy and termination rates. The discount rate is determined by reference to market yields on high quality corporate bonds. Since the discount rate is based on current yields, it is only a proxy for future yields. Key assumptions used to determine the retirement benefit cost and obligation are shown in Note 13.

Income taxes

Management periodically evaluates positions taken in tax filings where tax legislation is subject to interpretation, and records provisions where appropriate. The provisions are management's best estimates of the expenditures required to settle the present obligations at the balance sheet date measured using a probability weighting of possible outcomes.

22. CONTINGENCIES

Measurement inaccuracies occur from time to time on electricity metering facilities. These measurement adjustments are settled between the parties according to the Electricity and Gas Inspections Act (Canada) and related regulations. The AUC may disallow recovery of a measurement adjustment if it finds that controls and timely follow-up are inadequate.

The Company is party to a number of other disputes and lawsuits in the normal course of business. The Company believes that the ultimate liability arising from these matters will have no material impact on the non-consolidated financial statements.

In 2004, the Company and its affiliate, ATCO Gas, transferred their retail energy supply businesses to Direct Energy. The legal obligations of the Company and ATCO Gas for the retail functions transferred to Direct Energy, which include the supply of natural gas and electricity to customers as well as billing and customer care, remain if Direct Energy fails to perform. In certain circumstances, the functions will revert to the Company and/or ATCO Gas, with no refund of the transfer proceeds to Direct Energy.

Centrica plc., Direct Energy's parent company, provided a $300.0 million guarantee, supported by a $235.0 million letter of credit for Direct Energy's obligations to the Company and ATCO Gas under the transaction agreements. However, there can be no assurance that the coverage under these agreements will be adequate to defray all costs that could arise if the obligations are not met.

23. COMMITMENTS

In addition to commitments disclosed elsewhere in the non-consolidated financial statements, the Company has entered into a number of operating leases for office premises and equipment, a contract for information technology services and agreements to purchase capital assets. Approximate future undiscounted payments under these agreements are as follows:

	2020	2021	2022	2023	2024	2025 and thereafter
Purchase obligations:						
Operating and maintenance agreements	49,024	36,633	37,648	37,648	37,648	–
Capital expenditures	42,325	–	–	–	–	–
	91,349	36,633	37,648	37,648	37,648	–

24. RELATED PARTY TRANSACTIONS

TRANSACTIONS WITH RELATED PARTIES

During the year, ATCO Electric entered into the following transactions with related parties:

Entity	Relationship	Transaction	Recorded As	2019	2018
CU Inc. / Canadian Utilities Limited / ATCO Ltd.	Parent	Contract Services	Revenue	**7**	–
		Administration, financial management, aircraft and rent	Other expenses	**49,471**	46,449
		Aircraft, rent and leasehold improvements	Property, plant and equipment	**15,892**	22,367
		Licensing fees	Other expenses	**5,026**	6,404
		Interest income	Interest income	**416**	278
		Long-term and short-term interest expense and guarantee fees	Interest expense	**231,672**	230,548
Northland Utilities Enterprises Ltd.	Subsidiary	Administration, financial management, engineering services, materials management and metering services	Revenues	**1,441**	851
		Long-term and short-term interest income	Interest income	**1,639**	1,811
		Transfer of assets	Property, plant and equipment	**23**	40
ATCO Electric Yukon	Subsidiary	Administration, financial management, materials management and metering services	Revenues	**876**	840
		Long-term and short-term interest income	Interest income	**3,260**	3,401
		Short-term interest expense	Interest expense	**–**	80
ATCO Structures & Logistics	Affiliate	Administration and camp services	Revenues	**36**	10
		Trailer supply and noise management services and purchase of equipment	Property, plant and equipment	**61**	191
ATCO Gas	Affiliate	Administration and rent	Revenues	**1,415**	943
		Contract services	Revenues	**5**	–
		Administration, rent, joint trenching, electronics and instrumentation testing and purchase of equipment	Other expenses	**422**	521
		Contract services	Property, plant and equipment	**918**	–
		Transfer of assets	Property, plant and equipment	**–**	87

Entity	Relationship	Transaction	Recorded As	2019	2018
ATCO Power	Affiliate	Operate and maintain substations, project services, administration, procurement services, metering services and communication services	Revenues	**528**	12,369
		Rent	Other expenses	**–**	834
		Transfer of assets	Property, plant and equipment	**40**	–
ASHCOR	Affiliate	Contract services	Revenues	**278**	–
Alberta Power (2000) Ltd.	Affiliate	Contract services	Revenues	**7,988**	5
ATCO Energy Solutions Ltd.	Affiliate	Operate and maintain facilities, project services, communication services and administration	Revenues	**474**	220
		Fuel purchases	Fuel costs	**–**	1,381
ATCO Investments Ltd.	Affiliate	Project services	Revenues	**–**	52
		Rent	Rent, parking and utilities	**536**	3
		Contract services	Property, plant and equipment	**–**	3
ATCO Pipelines	Affiliate	Contract services	Revenues	**277**	148
		Contract services	Property, plant and equipment	**–**	68
		Transfer of assets	Property, plant and equipment	**–**	15
ATCO Energy Ltd.	Affiliate	Billing and call centre services	Revenues	**127**	57
		Retail service revenue	Revenues	**49,013**	36,314
		Distribution service costs	Other expenses	**2,114**	1,709
		Contract services	Other expenses	**64**	19
		Contract services	Property, plant and equipment	**–**	279
Alberta Powerline Limited Partnership	Affiliate	Administration	Revenues	**3,762**	6,941
ATCO-Valard Design Build Joint Venture	Joint Arrangement	Route development and project services	Revenues	**29,991**	39,154

Affiliate companies are subsidiaries of ATCO Electric's parent or ultimate parent.

ATCO Electric incurred $0.4 million (2018 - $0.4 million) in advertising and promotion expenses from an entity related through common control.

These transactions are in the normal course of business and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

RELATED PARTY LOANS AND BALANCES

Balances	Recorded As	2019	2018
Receivables from related parties (1)	Accounts receivable from parent company and affiliate companies	**6,322**	19,642
Payables to related parties (1)	Accounts payable to parent company and affiliate companies	**67,178**	68,244
Short-term advances (2)	Short-term advances to parent company	**34,000**	1,300
	Short-term advances from parent company	**15,000**	54,300
Long-term advances *(Note 12)*	Long-term debt to parent company	**5,008,880**	5,008,277
Equity preferred shares *(Note 15)*	Equity preferred shares to parent company	**141,968**	141,968

(1) Generally due within 30 days or less from the date of the transaction. The amounts outstanding are unsecured, bear no interest and will be settled in cash. No provisions are held against receivables from related parties.

(2) Short-term advances are obtained in the normal course of business and are generally due within 30 days or less from the date of the transaction. The interest rates are based on the Bank of Canada overnight rate plus an applicable spread.

Long-term advances to subsidiary companies

Long-term advances to subsidiary companies are shown in the table below.

	Effective Interest Rate	2019	2018
Yukon Electric			
Debentures - unsecured (1)	4.814% (2018 - 5.077%)	**68,100**	69,000
Northland Utilities Yellowknife			
Debentures - unsecured (1)	4.815% (2018 - 4.895%)	**24,063**	25,363
Northland Utilities NWT			
Debentures - unsecured (1)	3.850% (2018 - 5.820%)	**9,160**	9,300
		101,323	103,663
Less: amounts due within one year		**(1,500)**	(12,250)
		99,823	91,413

(1) Interest is the average effective interest rate weighted by principal amounts outstanding. The debentures mature between November 2020 and November 2052. Long-term advances are unsecured and will be settled in cash. No provisions are held against the advances.

25. SUBSEQUENT EVENTS

At the end of 2019, a novel strain of coronavirus (the COVID-19) was reported. The World Health Organization has since declared the outbreak to constitute a global pandemic. The COVID-19 outbreak is disrupting financial and commodity markets, supply chains, and affecting production and sales across different industries in private and public sectors. At this point, the extent to which the COVID-19 may impact the Company's operations, its financial position and performance is uncertain, and will depend on further developments, including the duration and spread of the outbreak, and its impact on the Company's customers, suppliers and employees.

26 ACCOUNTING POLICIES

RATE REGULATION

Nature and economic effects of rate regulation

The Company is regulated by the AUC. The AUC administers acts and regulations covering such matters as rates, financing, and service area.

Distribution Operations

The distribution operations of the Company are under a form of rate regulation called Performance Based Regulation (PBR). The current PBR period applies for a period of five years from 2018 to 2023. PBR allows distribution utilities the opportunity to recover prudently incurred costs of providing regulatory services and generate a fair return on investment. Under PBR, revenue is determined by a formula that adjusts customer rates for inflation and expected productivity improvements over a five year period.

Specifically, the PBR formula incorporates the following factors:

- Estimated annual inflation for input prices (I Factor)
- Less an offset to reflect expected productivity improvements during the PBR plan period (X Factor)

PBR also includes mechanisms to allow the Company to:

- Recover capital expenditures not recoverable through the PBR formula that meet certain criteria (K Factor)
- Recover from or refund to customers amounts outside of management's ability to control, that are material, should not have significantly influenced the I Factor, are prudently incurred, are recurring and could vary greatly from year to year (Y Factor) or are unforeseen and unlikely to recur (Z Factor).

Transmission Operations

The transmission operations of the Company are subject to a cost of service regulation under which the AUC establishes the revenues required to: (1) recover forecast operating costs of providing the regulated service, including depreciation and amortization and income taxes, and (2) provide a fair and reasonable return on utility investment, or rate base. Since actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

Rate base is the investment in property, plant and equipment and intangible assets approved by the AUC. The investment includes an allowance for working capital and is reduced by accumulated depreciation and amortization, reserves for future removal and site restoration costs, and unamortized contributions by utility customers for plant extensions. These operations earn a return on rate base intended to meet the cost of the debt and preferred share components of rate base and to provide share owners with a fair return on the common equity component of rate base.

The AUC approves rates of return for the debt and preferred share components of rate base which is based on the historical and forecast weighted average cost of debt and preferred shares. The AUC also establishes the capital structure.

The transmission operations of the Company seek approval for their revenue requirement either by submitting a general tariff application to the AUC or negotiating settlement with interested parties. In the latter case, the AUC monitors the negotiated settlement process and approves any agreement. The AUC may approve interim rates or the recovery of costs on a placeholder basis, subject to final determination.

Financial statement effects of rate regulation

In the absence of a rate-regulated standard under IFRS that the Company is eligible to adopt, the company does not recognize assets and liabilities from rate-regulated activities as may be directed by regulatory decisions. Instead, the Company records revenues in earnings when amounts are billed to customers consistent with the rate design approved by the AUC (see revenue recognition accounting policy below).

Operating costs and expenses are recorded when incurred. Costs incurred in constructing an asset that meets the asset recognition criteria are included in the related property, plant and equipment or intangible asset.

REVENUE RECOGNITION

Revenue is allocated to the respective performance obligations based on relative transaction prices, and is recognized as goods and services are delivered to the customer. Revenue is measured as the amount of consideration expected to be received in exchange for the goods transferred or services delivered. The amount of revenue recognized reflects the time value of money where a significant financing component has been identified.

Contract modifications are accounted for prospectively or as a cumulative catch-up adjustment depending on the nature of the change.

Where the amount of goods and services delivered to the customer corresponds directly to the amount invoiced, the Company recognizes revenue equal to what it has the right to invoice.

Where the Company arranges for another party to provide a specified good or service (that is, it does not control the specified good or service provided by another party before that good or service is transferred to the customer), only revenues net of payments to the other party for the goods or services provided are recognized.

Non-cash considerations received from the Company's customers are included in the amount of revenue recognized and measured at fair value.

Costs incurred directly to obtain or fulfill a contract are capitalized and amortized to expense over the life of the contract.

Electricity transmission

Revenue from electricity transmission services is recognized when service is provided to customers and is measured in proportion to the amount it has the right to invoice under the contract.

Customer contributions for extensions to plant are recognized as revenue over the life of the related asset.

Electricity distribution

Revenue from distribution of electricity is recognized when the services are provided to the customer based on metered consumption, which is adjusted periodically to reflect differences between estimated and actual consumption. Distribution of regulated and non-regulated electricity is based on tariff-approved rates established by the Alberta Electric Systems Operator. The Company recognizes revenue in an amount that corresponds directly with the services delivered and the amount invoiced.

Customer contributions for extensions to plant are recognized as revenue over the life of the related asset.

Franchise fees

Municipal governments charge franchise fees to the utilities in Canada for the exclusive right to provide service in their community. These costs are charged to customers through rates approved by the regulator. Franchise fees do not represent a separate performance obligation to a customer and are recovered through utility transmission and distribution prices. The recovery is part of the provision of continuous electricity transmission and distribution service performance obligation. Franchise fees invoiced to customers are recognized as revenues.

SHORT-TERM EMPLOYEE BENEFITS

Short-term employee benefits are recognized as an expense in salaries, wages and benefits as employees render service. These benefits include wages, salaries, social security contributions, short-term compensated absences, incentives and non-monetary benefits, such as medical care. Costs for employee services incurred in constructing an asset that meet the asset recognition criteria are included in the related property, plant and equipment or intangible asset.

Termination benefits are recognized as an expense in salaries, wages and benefits at the earlier of when the Company can no longer withdraw the offer of those benefits and when the Company recognizes costs for a restructuring that includes the payment of termination benefits. In the case of an offer made to encourage voluntary redundancy, the termination benefits are measured based on the number of employees expected to accept the offer.

INCOME TAXES

Income taxes are the sum of current and deferred taxes. Income tax is recognized in earnings, except to the extent it relates to items recorded in other comprehensive income (OCI) or in equity.

Current tax is calculated on taxable earnings using rates enacted or substantively enacted at the balance sheet date in the jurisdictions in which the Company operates.

The liability method is used to determine deferred income tax on temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Deferred income tax is calculated using the enacted or substantively enacted tax rates that are expected to apply in the period when the liability is settled or the asset is realized. If expected tax rates change, deferred income taxes are adjusted to the new rates.

Deferred income tax assets and liabilities are not recognized if the temporary differences arise from the initial recognition of goodwill or of other assets and liabilities in a transaction, other than a business combination, that does not affect accounting or taxable earnings. Deferred income tax assets are recognized only when it is probable that future taxable earnings will be available against which the temporary differences can be applied.

CASH

Cash consists of cash at bank less outstanding cheques.

INVENTORIES

Inventories are valued at the lower of cost or net realizable value. The cost of inventories that are interchangeable is assigned using the weighted average cost method. For inventories that are not interchangeable, cost is assigned using specific identification of their individual costs. Net realizable value is the estimated selling price in the ordinary course of business, less variable selling expenses.

The cost of inventories is comprised of all purchase, conversion and other costs to bring inventories to their present condition and location. Purchase costs consist of the purchase price, import duties, non-recoverable taxes, transport, handling and other costs directly attributable to the purchase of finished goods, materials or services. Conversion costs include direct material and labour costs and a systematic allocation of fixed and variable overheads incurred in converting materials into finished goods.

INVESTMENTS

The Company's investment in subsidiary companies is initially recognized at cost and only dividends received are taken into earnings. The exemption from applying the consolidation method has been used.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment are recorded at cost less accumulated depreciation and any recognized impairment losses. Cost includes expenditures that are directly attributable to the purchase or construction of the asset, such as materials, labour, borrowing costs incurred during construction, and contracted services. Subsequent costs are included in the asset's carrying amount or recognized as a separate asset only when it is probable that future economic benefits will flow to the Company and the cost can be measured reliably.

Borrowing costs attributable to a construction period of substantial duration are added to the cost of the asset. The effective interest method is used to calculate capitalized interest using specified rates for specific borrowings and a weighted average rate for general borrowings. Interest capitalization starts when borrowing costs and expenditures are incurred at the onset of construction and ends when construction is substantially complete.

The Company allocates the amount initially recognized in property, plant and equipment to its significant components and depreciates each component separately. Assets are depreciated mainly on a straight-line basis over their estimated useful lives. No depreciation is provided on land and construction work-in-progress.

The carrying amount of a replaced asset is derecognized when the cost of replacing the asset is capitalized. When an asset is derecognized, any resulting gain or loss is recorded in earnings.

Depreciation periods for the principal categories of property, plant and equipment are shown in the table below.

	Useful Life	Average Useful Life	Average Depreciation Rate
Utility transmission and distribution:			
Electricity transmission equipment	2 to 65 years	52 years	1.9%
Electricity distribution equipment	15 to 55 years	53 years	1.9%
Buildings	50 years	38 years	2.7%
Other plant, equipment and machinery	5 to 25 years	19 years	5.4%

Depreciation methods and the estimated residual values and useful lives of assets are reviewed on an annual basis. Any changes in these accounting estimates are recorded prospectively.

INTANGIBLES

Intangible assets are recorded at cost less accumulated amortization and any recognized impairment losses. The Company amortizes intangible assets on a straight-line basis over their useful lives. Useful life is not longer than 10 years for computer software and 75 years for land rights based on the contractual life of the underlying agreements. Software work-in-progress is not amortized as the software is not available for use.

Amortization methods and useful lives of assets are reviewed annually. Any changes in these accounting estimates are recorded prospectively.

IMPAIRMENT OF PROPERTY, PLANT AND EQUIPMENT AND INTANGIBLES

Property, plant and equipment and intangible assets with finite lives are tested for recoverability when events or circumstances indicate a possible impairment. Impairment is assessed at the CGU level, which is the smallest identifiable group of assets that generates independent cash inflows. An impairment loss is recognized in earnings when the CGU's carrying value is higher than its recoverable amount. The recoverable amount is the greater of the CGU's fair value less disposal costs and its value in use. An impairment loss may be reversed in whole or in part if there is objective evidence that a change in the estimated recoverable amount is warranted. A reversal of an impairment loss shall not exceed the carrying amount that would have been determined (net of depreciation) had no impairment loss been recognized for the asset in prior years.

PROVISIONS

The Company recognizes provisions when:

(i) there is a current legal or constructive obligation as a result of a past event;

(ii) a probable outflow of economic benefits will be required to settle the obligation; and

(iii) a reliable estimate of the obligation can be made.

If the effect is material, provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. If discounting is used, the increase in the provision due to the passage of time is recognized in interest expense.

CONTINGENCIES

A contingent liability is a possible obligation, and a contingent asset is a possible asset, that arises from past events and whose existence will be confirmed only by the occurrence or non-occurrence of one or more uncertain future events not wholly within the control of the Company. A contingent liability may also be a present obligation that arises from past events that is not recognized because it is not probable that an outflow of economic resources will be required to settle the obligation or the amount of the obligation cannot be measured reliably.

Neither contingent liabilities nor assets are recognized in the consolidated financial statements. However, a contingent liability is disclosed, unless the possibility of an outflow of resources is remote. A contingent asset is only disclosed where an inflow of economic benefits is probable.

Management evaluates the likelihood of contingent events based on the probability of exposure to potential loss. Actual results could differ from these estimates.

FINANCIAL INSTRUMENTS

The Company classifies financial assets when they are first recognized as amortized cost or fair value through profit or loss. Classification is determined based on the Company's business model for managing financial assets and the contractual cash flow characteristics of the financial assets. Financial assets are measured at amortized cost if the financial asset is:

(i) held for the purpose of collecting contractual cash flows, and

(ii) the contractual cash flows of the financial asset solely represent payments of principle and interest.

All other financial assets are classified as fair value through profit or loss.

Financial liabilities are classified as amortized cost or fair value through profit or loss.

Amortized cost

Financial instruments classified as amortized cost are initially measured at fair value and subsequently measured at their amortized cost using the effective interest method.

Fair value through profit or loss

Financial instruments classified as fair value through profit or loss are initially measured at fair value with subsequent changes in fair value recognized in earnings.

Transaction costs

Transaction costs directly attributable to the purchase or issue of financial assets or financial liabilities that are not fair value through profit or loss are added to the fair value of such assets or liabilities when initially recognized. Transaction costs for long-term debt are amortized over the life of the respective financial liability using the effective interest method. The Company's long-term debt and equity preferred shares are presented net of their respective transaction costs.

Offsetting financial instruments

Financial assets and financial liabilities are offset and the net amount is reported in the consolidated balance sheet:

(i) if there is a legally enforceable right to offset the recognized amounts, and

(ii) if the Company intends either to settle on a net basis or to realize the assets and settle the liabilities simultaneously.

Derecognition of financial instruments

Financial assets are derecognized:

(i) when the right to receive cash flows from the financial assets has expired or been transferred, and

(ii) the Company has transferred substantially all the risks and rewards of ownership.

Financial liabilities are derecognized when the obligation is discharged, cancelled, or expired.

Fair value hierarchy

The Company uses quoted market prices when available to estimate fair value. Models incorporating observable market data, along with transaction specific factors, are also used to estimate fair value. Financial assets and liabilities are classified in the fair value hierarchy according to the lowest level of input that is significant to the fair value measurement. Management's judgment as to the significance of a particular input may affect placement within the fair value hierarchy levels.

The hierarchy is as follows:

- Level 1: quoted prices (unadjusted) in active markets for identical assets or liabilities.
- Level 2: inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly (i.e., as prices) or indirectly (i.e., derived from prices).
- Level 3: inputs for the asset or liability that are not based on observable market data (unobservable inputs).

The Company applies settlement date accounting to the purchases and sales of financial assets. Settlement date accounting means recognizing an asset on the day it is received by the Company and recognizing the disposal of an asset on the day it is delivered by the Company. Any gain or loss on disposal is also recognized on that day.

IMPAIRMENT OF FINANCIAL INSTRUMENTS

At each reporting date, the Company assesses whether there is evidence that a financial asset or group of financial assets is impaired. If such evidence exists, an impairment loss is recognized in earnings.

Impairment losses on financial assets carried at amortized cost are calculated as the difference between the amortized cost and the present value of estimated future cash flows discounted at the financial asset's original effective interest rate. Impairment losses on financial assets carried at amortized cost may be reversed in whole or in part if there is evidence that a change in the estimated recoverable amount is warranted. The revised recoverable amount cannot exceed the carrying amount that would have been determined had no impairment charge been recognized in previous periods.

From January 1, 2018, the Company applies the expected credit loss allowance matrix based on historical credit loss experience, aging of financial assets, default probabilities, forward-looking information specific to the counterparty, and industry-specific economic outlooks.

For accounts receivable and contract assets, the Company estimates credit loss allowances at initial recognition and throughout the life of the receivable.

RETIREMENT BENEFITS

The Company participates, together with Canadian Utilities Limited and its subsidiary companies, in a registered group defined benefit pension plan (the Group Plan). The assets of the Group Plan are not segregated for each participating entity and are used to provide pensions to all members of this plan. In this circumstance, the Company is required to account for the Group Plan as a defined contribution plan whereby contributions are expensed as paid. Contributions related to current service cost are allocated in proportion to capped pensionable earnings for each company. Contributions related to the amortization of the unfunded liability are allocated in proportion to the corresponding going-concern liability for each company which was established based on the actuarial valuations for funding purposes as of December 31, 2017.

The minimum funding requirements for the Group Plan are comprised of the contributions related to current service cost and the amortization of the unfunded liability as determined by the actuary. The Company does not have any liability to the Group Plan other than the minimum funding requirements of its subsidiaries. In the event of a withdrawal from the Group Plan or the termination of the Group Plan, the companies will still be required to contribute to the Group Plan where such contributions are required under pension regulations.

The Company participates, together with Canadian Utilities Limited and its subsidiary companies, in OPEB and non-registered group defined benefit pension plans. These plans are administered on a combined basis, and the Company accrues for its obligations under these plans. Costs of these benefits are determined using the projected unit credit method and reflect management's best estimates of wage and salary increases, age at retirement and expected health care costs. The Company consults with qualified actuaries when setting the assumptions used to estimate benefit obligations and the cost of providing retirement benefits during the period.

Accrued benefit obligations at the balance sheet date are determined using a discount rate that reflects market interest rates. The rates are equivalent to those on high quality corporate bonds that match the timing and amount of expected benefit payments.

For the non-registered defined benefit pension plans, the Company is assessed a percentage of the total cost of the plans.

For the non-registered defined benefit pension plan and the OPEB plans, gains and losses resulting from changes in assumptions, including the liability discount rate and future compensation rates, used to measure the accrued benefit obligations are recognized in OCI in the period in which they occur. Those gains and losses are then transferred directly to retained earnings.

Employer contributions to the defined contribution pension plans are expensed as employees render service.

For non-registered defined benefit pension plans and OPEB plans, service cost is recognized as an expense in salaries, wages and benefits, and net interest expense is recognized in interest expense. The cost of retirement benefits for registered defined benefit pension plans and defined contribution pension plans is recognized as an expense in salaries, wages and benefits. Past service costs are recognized immediately in earnings in the period of a plan amendment or curtailment. When retirement benefit costs for employee services are incurred in constructing an asset and meet asset recognition criteria, they are included in the related property, plant and equipment or intangible asset.

RELATED PARTY TRANSACTIONS

Transactions with related parties in the normal course of business are measured at the exchange amount. Transfers of assets between entities under common control are measured at the carrying amount.

LEASES

The Company as a lessee

At the inception of a contract, the Company assesses whether the contract is, or contains, a lease based on whether the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration.

A right-of-use asset representing the right to use the underlying asset with a corresponding lease liability is recognized when the leased asset becomes available for use by the Company.

The right-of-use asset is recognized at cost and is depreciated on a straight-line basis over the shorter of the estimated useful life of the asset and the lease term on a straight-line basis. The cost of the right-of-use asset is based on the following:

- the amount of initial recognition of related lease liability;
- adjusted by any lease payments made on or before inception of the lease;
- increased by any initial direct costs incurred; and
- decreased by lease incentives received and any costs to dismantle the leased asset.

The lease term includes consideration of an option to extend or to terminate if the Company is reasonably certain to exercise that option. In addition, the right-of-use asset is periodically reduced by impairment losses, if any, and adjusted for certain re-measurements of the lease liability.

Lease liabilities are initially recognized at the present value of the lease payments. The lease payments are discounted using the interest rate implicit in the lease or, if that rate cannot be readily determined, the Company's incremental borrowing rate. Generally, the Company uses its incremental borrowing rate as the discount rate. Subsequent to recognition, lease liabilities are measured at amortized cost using the effective interest rate method. Lease liabilities are remeasured when there is a change in future lease payments arising mainly from a change in an index or rate, if there is a change in the Company's estimate of the amount expected to be payable under a residual value guarantee, or if the Company changes its assessment of whether it will exercise a purchase, renewal or termination option.

The payments related to short-term leases and low-value leases are recognized as other expenses over the lease term in the consolidated statements of earnings.

Prior to January 1, 2019, when the Company had purchased goods or services as a lessee, and the lease was an operating lease, rental payments were expensed on a straight-line basis over the life of the lease. Contingent rents were recognized in earnings in the period in which they were incurred. Contingent rent was that portion of lease payments that was not fixed in amount but varied based on a future factor, such as the amount of use or production.

The Company as a lessor

A finance lease exists when the terms of the lease transfer substantially all the risks and rewards incidental to ownership of the leased asset to the lessee. Amounts due from lessees under finance leases are recorded as finance lease receivables. They are initially recognized at amounts equal to the present value of the minimum lease payments receivable. Payments that are part of the leasing arrangement are divided between a reduction in the finance lease receivable and finance lease income. Finance lease income is recognized so as to produce a constant rate of return on the Company's investment in the lease and is included in revenues.

ACCOUNTING STANDARDS AND INTERPRETATIONS NOT YET ADOPTED

At December 31, 2019, there are no new or amended standards and interpretations that need to be adopted in future periods and will have a significant impact on the Company.