EXHIBIT 2 – RATE BASE

2023 Cost of Service

Cooperative Hydro Embrun Inc.
EB-2022-0022

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2.1. OVERVIEW OF RATE BASE

CHEI's methodology of calculating its Rate Base has not changed from its last two costs of service applications (2014 and 2018) and is in line with the OEB's methodology of determining a Rate Base. The net fixed assets used to determine the utility's Rate Base include those distribution assets associated with activities that enable the conveyance of electricity for distribution purposes. CHEI does not have non-distribution assets, nor does it conduct non-distribution activities. Controllable expenses include operations and maintenance, billing and collecting, and administration costs discussed in detail in Exhibit 4.

CHEI has calculated its' Test Year 2023 Rate Base to be $4,750,587. This rate base is also used to determine the proposed revenue requirement found in Exhibit 6. The table below presents CHEI's Rate Base calculations for the Test Year compared to the 2018 Board Approved.

Table 1 – Change in Rate Base from 2018BA

Particulars	Last Board Approved	2023	Var from 2018
Net Capital Assets in Service:			
Year End Capex	$6,244,627	$7,185,613	$940,986
Year End Accumulated Depreciation	$1,879,790	$2,708,489	$828,699
Net Book	$4,364,837	$4,477,124	$112,287
Working Capital Allowance	$315,570	$303,462	-$12,108
Total Rate Base	**$4,680,407**	**$4,780,587**	**$100,180**
	MIFRS	**MIFRS**	
Expenses for Working Capital	**Last Board Approved**	**2023**	**Var from 2018**
Eligible Distribution Expenses:			
3500-Distribution Expenses - Operation	$36,569	$47,439	$10,870
3550-Distribution Expenses - Maintenance	$53,115	$49,486	-$3,629
3650-Billing and Collecting	$199,982	$244,306	$44,324
3700-Community Relations	$5,150	$3,521	-$1,629
3800-Administrative and General Expenses	$385,155	$408,405	$23,250
LEAP	$2,000		-$2,000
			$0
Total Eligible Distribution Expenses	$681,971	$753,157	$71,186
3350-Power Supply Expenses	$3,525,627	$3,293,006	-$232,621
Total Expenses for Working Capital	$4,207,598	$4,046,164	-$161,434
Working Capital factor	7.5%	7.5%	0.0%
Total Working Capital	**$315,570**	**$303,462**	**-$12,108**

2.1.1 Rate Base Trend and Cost Drivers

The Rate Base trend table presents CHEI's Rate Base calculations for all required years, including the Test Year 2023. Year-over-year variance analysis follows.

Table 2 – Rate Base Trend

Particulars	Last Board Approved	2018	2019	2020	2021	2022	2023	Var from 2018
Net Capital Assets in Service:								
Year End CapEx	$6,244,627	$6,179,364	$6,335,414	$6,482,154	$6,639,254	$6,923,626	$7,185,613	$940,986
Year End Accumulated Depreciation	$1,879,790	$1,871,913	$2,021,994	$2,183,694	$2,353,872	$2,528,740	$2,708,489	$828,699
Net Book	$4,364,837	$4,307,452	$4,313,420	$4,298,460	$4,285,381	$4,394,886	$4,477,124	$112,287
Working Capital Allowance	$315,570	$287,303	$315,806	$391,955	$389,248	$295,418	$303,462	-$12,108
Total Rate Base	**$4,680,407**	**$4,594,755**	**$4,629,225**	**$4,690,416**	**$4,674,629**	**$4,690,303**	**$4,780,587**	**$100,180**
Expenses for Working Capital	**Last Board Approved**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**Var from 2018**
<u>Eligible Distribution Expenses:</u>								
3500- Expenses - Operation	$36,569	$36,569	$44,096	$49,131	$44,455	$45,923	$47,439	$10,870
3550--Expenses - Maintenance	$53,115	$53,115	$38,679	$62,243	$46,375	$47,905	$49,486	-$3,629
3650-Billing and Collecting	$199,982	$199,982	$219,757	$214,452	$217,108	$236,739	$244,306	$44,324
3700-Community Relations	$5,150	$5,150	$4,628	$4,445	$3,300	$3,409	$3,521	-$1,629
3800-Admin and General Expenses	$385,155	$387,155	$391,298	$408,195	$391,128	$405,812	$408,405	$23,250
LEAP	$2,000							-$2,000
								$0
Total Eligible Distribution Expenses	$681,971	$681,971	$698,458	$738,467	$702,365	$739,788	$753,157	$71,186
3350-Power Supply Expenses	$3,525,627	$3,148,742	$3,512,283	$4,487,602	$4,487,602	$3,199,114	$3,293,006	-$232,621
Total Expenses for Working Capital	$4,207,598	$3,830,713	$4,210,741	$5,226,070	$5,189,967	$3,938,902	$4,046,164	-$161,434
Working Capital factor	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	0.0%
Total Working Capital	**$315,570**	**$287,303**	**$315,806**	**$391,955**	**$389,248**	**$295,418**	**$303,462**	**-$12,108**

CHEI notes that it uses "in-service", "capital additions" and "capital expenditures" interchangeably as CHEI does not have any Work in Progress capital projects.

The Rate Base for the 2023 Test Year has increased by $100,180 over the last board approved. CHEI has added $1,166,303 in assets since 2018. The reason for the increase from the 2018 Cost of Service is mainly attributed to the following:

Major capital cost drivers: 2018	**Acct**	**$**
System Access:		
• New O/H and U/G services	1855	$20,819
• Centre Urgel Forget Phase II	1850	$11,685
• Centre Urgel Forget Phase II	1845	$17,800

- New Meters 1860 $17,552

System Renewal:

- Pole Replacement 1830 $43,800
- Transformer Replacement 1850 $66,468
- Transformer Elbows and Inserts 1850 $13,113

Major capital cost drivers: 2019

System Access:

- New O/H and U/G services 1855 $23,364
- Transformer 225 KvA 1850 $14,219
- Meter Replacement (Seal Years) 1860 $16,372
- Scada Improvement 1820 $33,653
- Relocate Line St-Jaques Phase I 1835 $20,000
- New Transformer Inventory 1850 $21,460
- Enhancement Blais Street 1835 $16,240

System Renewal:

- Transformer Replacement 1850 $22,261
- Transformer Elbows and Inserts 1850 $10,139

Major capital cost drivers: 2020

System Access:

- New O/H and U/G services 1855 $31,633
- Versailles III Project 1850 $23,735
- Versailles III Project 1845 $66,142
- Patenaude East Subdivision Phase II 1850 $33,425
- Patenaude East Subdivision Phase II 1845 $65,794
- Meter Replacement (Seal Years) 1860 $8,943
- New Transformers Inventory 1850 $9,000

System Renewal:

- Pole Replacement 1830 $16,425
- Transformer Replacement 1850 $40,079
- Transformer Elbows and Inserts 1850 $21,041

Major capital cost drivers: 2021

System Access:

- New O/H and U/G services 1855 $30,000
- Meter 1860 $12,093
- New Transformers Inventory 1850 $8,465

System Renewal:

- Pole Replacement 1830 $23,300
- Transformer Replacement 1850 $50,150
- Replacement of Switch Arrester 1850 $27,610

Major capital cost drivers: 2022

System Access:

- New O/H and U/G services 1855 $23,000
- Meter 1860 $12,000
- New Transformers Inventory 1850 $8,000

- Project Central Park (Transformers) 1850 $50,000
- Project Central Park (Underground Cable & Labour) 1845 $115,000
- Project Central Park(Dip Pole & Labour) 1830 $3,800
- Project Central Park (Primary Overhead Cable & Labour)) 1835 $4,500

- Project Mélanie Phase III (Transformers) 1845 $38,000
- Project Mélanie Phase III (Underground Cable & Labour) 1830 $65,000
- Project Mélanie Phase III (Dip Pole & Labour) 1835 $4,500
- Project Mélanie Phase III (Primary Overhead Cable & Labour)) $7,500

System Renewal:

- Pole Replacement 1830 $17,400
- Transformer Replacement 1850 $84,825
- Replacement of Switch Arrester 1850 $10,000

Major capital cost drivers: 2023

System Access:

- New O/H and U/G services 1855 $20,000
- Meter 1860 $12,000
- New Transformers Inventory 1850 $8,000

System Renewal:

- Pole Replacement 1830 $23,650
- Transformer Replacement 1850 $73,400
- Replacement of Switch Arrester 1850 $10,000

Decreased Power Supply Expenses

CHEI has forecasted a decrease in the 2022 and 2023 Power Supply Expenses over its' 2018 Cost of Service. This is due to the Ontario Electricity Rebate credit being applied to Regulated Price Plan billing components since 2021.

2.2. FIXED ASSET

2.2.1 Fixed Asset Continuity

This Schedule presents a continuity schedule of its investment in capital assets, the associated accumulated amortization, and the net book value for each Capital USoA account for the 2018 to 2021 Actuals and 2022 Bridge and 2023 Test Years.

CHEI attests that the OEB Appendices 2-BA continuity statements presented in the Chapter 2 Appendices 2-AB and at Appendix 2C reconcile with the calculated depreciation expenses at section 2.2.3 and presented by asset account. The utility also attests that the net book value balances reported on Appendix 2-BA and balances reconcile with the rate base calculation. The Excel version of the OEB Appendices is filed in conjunction with this application.

Information on year-over-year variance and explanations where variances exceed the materiality threshold is summarized in the previous section 2.1.3 and explained in detail in CHEI's 2023 Distribution System Plan.

CHEI does not have any asset retirement obligations (AROs) or any associated depreciation or accretion expenses related to an asset retirement obligation.

Accumulated Depreciation

CHEI has adopted depreciation rates based on the Kinectrics Asset Depreciation Study, which can be found at the following secure link:

https://www.oeb.ca/oeb/_Documents/EB-2010-0178/Kinetrics-418033-OEB%20Asset%20Amortization-%20Final%20Rep.pdf

The depreciation rates, CHEI's capitalization policy, methodology, and depreciation expenses continuity schedules are presented in section 2.2.3.

Below are the Fixed Asset Continuity Schedules for 2018 to 2023.

Table 3 – 2018 Continuity schedule

Year 2018 IFRS

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value	AVG Gross Bal	AVG AccDep
	1606	Organization	$374			$374	$374		$0	$374	$0	$374	$374
12	1611	Computer Software (Formally known as Account 1925)	$139,652	$1,081	$0	$140,733	$115,882	$11,005	$0	$126,887	$13,846	$140,192	$121,384
N/A	1805	Land	$50,000	$6,900	$0	$56,900	$0	$0	$0	$0	$56,900	$53,450	$0
47	1820	Distribution Station Equipment <50 kV	$1,949,404	$935	$0	$1,950,339	$125,972	$35,452	$0	$161,425	$1,788,914	$1,949,871	$143,698
47	1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
47	1830	Poles, Towers & Fixtures	$796,246	$47,975	-$8,116	$836,105	$286,180	$20,303	-$4,964	$301,518	$534,587	$816,175	$293,849
47	1835	Overhead Conductors & Devices	$982,191	$20,181	$0	$1,002,372	$287,534	$16,538	$0	$304,072	$698,299	$992,281	$295,803
47	1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
47	1845	Underground Conductors & Devices	$1,882,036	$17,800	$0	$1,899,836	$633,307	$54,027	$0	$687,334	$1,212,501	$1,890,936	$660,321
47	1850	Line Transformers	$1,215,795	$91,267	-$18,875	$1,288,187	$399,154	$31,064	-$11,545	$418,672	$869,515	$1,251,991	$408,913
47	1855	Services (Overhead & Underground)	$309,981	$20,819	$0	$330,799	$81,963	$8,010	$0	$89,973	$240,826	$320,390	$85,968
47	1860	Meters	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0
47	1860	Meters (Smart Meters)	$368,927	$17,552	$0	$386,479	$118,509	$25,180	$0	$143,689	$242,790	$377,703	$131,099
8	1915	Office Furniture & Equipment (10 years)	$54,220	$2,772	$0	$56,993	$45,282	$2,664	$0	$47,946	$9,046	$55,606	$46,614
8	1915	Office Furniture & Equipment (5 years)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	1920	Computer Equipment - Hardware	$31,939	$0	$0	$31,939	$28,190	$1,271	$0	$29,462	$2,477	$31,939	$28,826
8	1935	Stores Equipment	$4,320	$0	$0	$4,320	$4,320	$0	$0	$4,320	$0	$4,320	$4,320
8	1940	Tools, Shop & Garage Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	1945	Measurement & Testing Equipment	$15,901	$0	$0	$15,901	$7,450	$1,162	$0	$8,612	$7,289	$15,901	$8,031
47	1995	Contributions & Grants	-$1,691,644	-$60,245	$0	-$1,751,888	-$335,768	-$43,044	$0	-$378,812	-$1,373,076	-$1,721,766	-$357,290
						$0	$0	$0	$0	$0	$0	$0	$0
		Sub-Total	**$6,109,341**	**$167,037**	**-$26,991**	**$6,249,387**	$1,798,351	$163,632	-$16,509	**$1,945,474**	**$4,303,913**	$6,179,364	$1,871,913
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)				$0				$0	$0		$4,307,452
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)				$0				$0	$0		
		Total PP&E	**$6,109,341**	**$167,037**	**-$26,991**	**$6,249,387**	**$1,798,351**	**$163,632**	**-$16,509**	**$1,945,474**	**$4,303,913**		
		Total						**$163,632**					

10		Transportation
8		Stores Equipment
8		Tools, Shop
8		Meas/Testing
8		Communication

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Tools, Shop	
Meas/Testi	
Communication	
Net Depreciation	$163,632

Table 4 – 2019 Continuity schedule

Year 2019 IFRS

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value	AVG Gross Bal	AVG AccDep
	1606	Organization	$374			$374	$374			$374	$0	$374	$374
12	1611	Computer Software (Formally known as Account 1925)	$140,733	$2,988	$0	$143,721	$126,887	$7,314	$0	$134,201	$9,520	$142,227	$130,544
N/A	1805	Land	$56,900	$0	$0	$56,900	$0	$0	$0	$0	$56,900	$56,900	$0
47	1820	Distribution Station Equipment <50 kV	$1,950,339	$40,677	$0	$1,991,015	$161,425	$35,831	$0	$197,255	$1,793,760	$1,970,677	$179,340
47	1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
47	1830	Poles, Towers & Fixtures	$836,105	$2,500	-$8,116	$830,490	$301,518	$20,934	-$5,167	$317,285	$513,204	$833,297	$309,402
47	1835	Overhead Conductors & Devices	$1,002,372	$38,775	$0	$1,041,146	$304,072	$17,029	$0	$321,102	$720,045	$1,021,759	$312,587
47	1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
47	1845	Underground Conductors & Devices	$1,899,836	$2,360	$0	$1,902,196	$687,334	$54,315	$0	$741,649	$1,160,547	$1,901,016	$714,492
47	1850	Line Transformers	$1,288,187	$68,080	-$8,580	$1,347,687	$418,672	$32,798	-$5,462	$446,008	$901,679	$1,317,937	$432,340
47	1855	Services (Overhead & Underground)	$330,799	$23,364	$0	$354,163	$89,973	$8,562	$0	$98,535	$255,628	$342,481	$94,254
47	1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
47	1860	Meters (Smart Meters)	$386,479	$16,372	$0	$402,851	$143,689	$26,311	$0	$170,000	$232,851	$394,665	$156,845
8	1915	Office Furniture & Equipment (10 years)	$56,993	$909	$0	$57,901	$47,946	$2,575	$0	$50,521	$7,380	$57,447	$49,234
8	1915	Office Furniture & Equipment (5 years)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	1920	Computer Equipment - Hardware	$31,939	$4,598	$0	$36,537	$29,462	$1,523	$0	$30,985	$5,552	$34,238	$30,223
8	1935	Stores Equipment	$4,320	$0	$0	$4,320	$4,320	$0	$0	$4,320	$0	$4,320	$4,320
8	1940	Tools, Shop & Garage Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	1945	Measurement & Testing Equipment	$15,901	$0	$0	$15,901	$8,612	$1,162	$0	$9,774	$6,127	$15,901	$9,193
47	1995	Contributions & Grants	-$1,751,888	-$11,125	$0	-$1,763,013	-$378,812	-$43,937	$0	-$422,748	-$1,340,265	-$1,757,451	-$400,780
		Sub-Total	**$6,249,387**	**$189,497**	**-$16,696**	**$6,422,189**	**$1,945,474**	**$164,417**	**-$10,629**	**$2,099,262**	**$4,322,926**	$6,335,414	$2,021,994
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)				$0				$0	$0		$4,313,420
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)				$0				$0	$0		$4,313,420
		Total PP&E	**$6,249,387**	**$189,497**	**-$16,696**	**$6,422,189**	**$1,945,474**	**$164,417**	**-$10,629**	**$2,099,262**	**$4,322,926**		
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)											
		Total						**$164,417**					

10		Transportation
8		Stores Equipment
8		Tools, Shop
8		Meas/Testing
8		Communication

Less: *Fully Allocated Depreciation*
Transportation
Stores Equipment
Tools, Shop
Meas/Testi
Communication
Net Depreciation $164,417

Table 5 – 2020 Continuity schedule

Year 2020 IFRS

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value	AVG Gross Bal	AVG AccDep
	1606	Organization	$374			$374	$374			$374	$0	$374	$374
12	1611	Computer Software (Formally known as Account 1925)	$143,721	$628	$0	$144,349	$134,201	$3,625	$0	$137,826	$6,523	$144,035	$136,013
N/A	1805	Land	$56,900	$0	$0	$56,900	$0	$0	$0	$0	$56,900	$56,900	$0
47	1820	Distribution Station Equipment <50 kV	$1,991,015	$0	$0	$1,991,015	$197,255	$36,200	$0	$233,455	$1,757,560	$1,991,015	$215,355
47	1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
47	1830	Poles, Towers & Fixtures	$830,490	$24,541	$0	$855,031	$317,285	$21,125	$0	$338,410	$516,621	$842,760	$327,848
47	1835	Overhead Conductors & Devices	$1,041,146	$0	$0	$1,041,146	$321,102	$17,352	$0	$338,454	$702,692	$1,041,146	$329,778
47	1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
47	1845	Underground Conductors & Devices	$1,902,196	$131,936	$0	$2,034,131	$741,649	$56,233	$0	$797,882	$1,236,249	$1,968,163	$769,766
47	1850	Line Transformers	$1,347,687	$159,101	$0	$1,506,788	$446,008	$40,138	$0	$486,146	$1,020,643	$1,427,238	$466,077
47	1855	Services (Overhead & Underground)	$354,163	$31,633	$0	$385,796	$98,535	$9,250	$0	$107,785	$278,011	$369,979	$103,160
47	1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
47	1860	Meters (Smart Meters)	$402,851	$8,943	$0	$411,794	$170,000	$27,155	$0	$197,155	$214,639	$407,323	$183,578
8	1915	Office Furniture & Equipment (10 years)	$57,901	$3,431	$0	$61,332	$50,521	$2,491	$0	$53,012	$8,320	$59,617	$51,767
8	1915	Office Furniture & Equipment (5 years)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	1920	Computer Equipment - Hardware	$36,537	$617	$0	$37,153	$30,985	$1,958	$0	$32,943	$4,210	$36,845	$31,964
8	1935	Stores Equipment	$4,320	$0	$0	$4,320	$4,320	$0	$0	$4,320	$0	$4,320	$4,320
8	1940	Tools, Shop & Garage Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	1945	Measurement & Testing Equipment	$15,901	$0	$0	$15,901	$9,774	$1,162	$0	$10,936	$4,965	$15,901	$10,355
47	1995	Contributions & Grants	-$1,763,013	-$240,151	$0	-$2,003,164	-$422,748	-$47,077	$0	-$469,825	-$1,533,339	-$1,883,089	-$446,287
		Sub-Total	**$6,422,189**	**$120,679**	**$0**	**$6,542,868**	**$2,099,262**	**$169,611**	**$0**	**$2,268,874**	**$4,273,994**	$6,482,154	$2,183,694
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)				$0				$0	$0		$4,298,460
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)				$0				$0	$0		$4,298,460
		Total PP&E	**$6,422,189**	**$120,679**	**$0**	**$6,542,868**	**$2,099,262**	**$169,611**	**$0**	**$2,268,874**	**$4,273,994**		
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)											
		Total						**$169,611**					

10		Transportation
8		Stores Equipment
8		Tools, Shop
8		Meas/Testing
8		Communication

Less: ***Fully Allocated Depreciation***	
Transportation	
Stores Equipment	
Tools, Shop	
Meas/Testi ng	
Communication	
Net Depreciation	$169,611

Table 6 – 2021 Continuity schedule

Year **2021** **IFRS**

CCA Class	OEB	Description	Cost				Accumulated Depreciation						
			Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value	AVG Gross Bal	AVG AccDep
12	1611	Computer Software (Formally known as Account 1925)	$144,349	$36,105	$0	$180,454	$137,826	$7,037	$0	$144,862	$35,592	$162,402	$141,344
N/A	1805	Land	$56,900	$0	$0	$56,900	$0	$0	$0	$0	$56,900	$56,900	$0
47	1820	Distribution Station Equipment <50 kV	$1,991,015	$0	$0	$1,991,015	$233,455	$36,200	$0	$269,656	$1,721,360	$1,991,015	$251,556
47	1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
47	1830	Poles, Towers & Fixtures	$855,031	$31,528	$0	$886,558	$338,410	$21,770	$0	$360,180	$526,378	$870,794	$349,295
47	1835	Overhead Conductors & Devices	$1,041,146	$2,085	$0	$1,043,231	$338,454	$17,370	$0	$355,824	$687,407	$1,042,189	$347,139
47	1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
47	1845	Underground Conductors & Devices	$2,034,131	$5,085	$0	$2,039,216	$797,882	$58,191	$0	$856,073	$1,183,143	$2,036,674	$826,977
47	1850	Line Transformers	$1,506,788	$95,125	$0	$1,601,913	$486,146	$38,421	$0	$524,567	$1,077,346	$1,554,351	$505,356
47	1855	Services (Overhead & Underground)	$385,796	$30,000	$0	$415,796	$107,785	$10,020	$0	$117,805	$297,991	$400,796	$112,795
47	1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
47	1860	Meters (Smart Meters)	$411,794	$12,093	$0	$423,887	$197,155	$27,856	$0	$225,011	$198,875	$417,840	$211,083
8	1915	Office Furniture & Equipment (10 years)	$61,332	$750	$0	$62,082	$53,012	$1,230	$0	$54,243	$7,839	$61,707	$53,628
8	1915	Office Furniture & Equipment (5 years)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	1920	Computer Equipment - Hardware	$37,153	$750	$0	$37,903	$32,943	$1,818	$0	$34,761	$3,142	$37,528	$33,852
8	1935	Stores Equipment	$4,320	$0	$0	$4,320	$4,320	$0	$0	$4,320	$0	$4,320	$4,320
8	1940	Tools, Shop & Garage Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	1945	Measurement & Testing Equipment	$15,901	$0	$0	$15,901	$10,936	$1,162	$0	$12,098	$3,803	$15,901	$11,517
47	1995	Contributions & Grants	-$2,003,164	-$20,000	$0	-$2,023,164	-$469,825	-$50,329	$0	-$520,155	-$1,503,010	-$2,013,164	-$494,990
		Sub-Total	**$6,542,494**	**$193,519**	**$0**	**$6,736,013**	**$2,268,500**	**$170,745**	**$0**	**$2,439,245**	**$4,296,769**	$6,639,254	$2,353,872
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)				$0				$0	$0		$4,285,381
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)				$0				$0	$0		$4,285,381
		Total PP&E	**$6,542,494**	**$193,519**	**$0**	**$6,736,013**	**$2,268,500**	**$170,745**	**$0**	**$2,439,245**	**$4,296,769**		
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)											
		Total						**$170,745**					

10		Transportation
8		Stores Equipment
8		Tools, Shop
8		Meas/Testing
8		Communication

Less: ***Fully Allocated Depreciation***	
Transportation	
Stores Equipment	
Tools, Shop	
Meas/Testi	
Communication	
Net Depreciation	$170,745

Table 7 – 2022 Continuity schedule

Year **2022 IFRS**

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value	AVG Gross Bal	AVG AccDep
12	1611	Computer Software (Formally known as Account 1925)	$180,454	$3,000	$0	$183,454	$144,862	$10,947	$0	$155,809	$27,645	$181,954	$150,336
N/A	1805	Land	$56,900	$0	$0	$56,900	$0	$0	$0	$0	$56,900	$56,900	$0
47	1820	Distribution Station Equipment <50 kV	$1,991,015	$0	$0	$1,991,015	$269,656	$36,200	$0	$305,856	$1,685,159	$1,991,015	$287,756
47	1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
47	1830	Poles, Towers & Fixtures	$886,558	$25,700	$0	$912,258	$360,180	$22,382	$0	$382,561	$529,697	$899,408	$371,371
47	1835	Overhead Conductors & Devices	$1,043,231	$12,000	$0	$1,055,231	$355,824	$17,387	$0	$373,211	$682,020	$1,049,231	$364,517
47	1840	Underground Conduit	$0	$0	$0	$0	$0		$0	$0	$0	$0	$0
47	1845	Underground Conductors & Devices	$2,039,216	$180,000	$0	$2,219,216	$856,073	$58,263	$0	$914,336	$1,304,880	$2,129,216	$885,204
47	1850	Line Transformers	$1,601,913	$196,825	$0	$1,798,738	$524,567	$40,970	$0	$565,537	$1,233,201	$1,700,326	$545,052
47	1855	Services (Overhead & Underground)	$415,796	$23,000	$0	$438,796	$117,805	$10,645	$0	$128,449	$310,347	$427,296	$123,127
47	1860	Meters	$0	$0	$0	$0	$0		$0	$0	$0	$0	$0
47	1860	Meters (Smart Meters)	$423,887	$12,000	$0	$435,887	$225,011	$28,493	$0	$253,504	$182,383	$429,887	$239,257
8	1915	Office Furniture & Equipment (10 years)	$62,082	$1,200	$0	$63,282	$54,243	$1,328	$0	$55,571	$7,711	$62,682	$54,907
8	1915	Office Furniture & Equipment (5 years)	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0
10	1920	Computer Equipment - Hardware	$37,903	$1,500	$0	$39,403	$34,761	$2,043	$0	$36,804	$2,599	$38,653	$35,783
8	1935	Stores Equipment	$4,320	$0	$0	$4,320	$4,320	$0	$0	$4,320	$0	$4,320	$4,320
8	1940	Tools, Shop & Garage Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	1945	Measurement & Testing Equipment	$15,901	$0	$0	$15,901	$12,098	$1,162	$0	$13,260	$2,641	$15,901	$12,679
47	1995	Contributions & Grants	-$2,023,164	-$80,000	$0	-$2,103,164	-$520,155	-$50,829	$0	-$570,984	-$1,532,180	-$2,063,164	-$545,569
		Sub-Total	**$6,736,013**	**$375,225**	**$0**	**$7,111,238**	**$2,439,245**	**$178,991**	**$0**	**$2,618,235**	**$4,493,003**	$6,923,626	$2,528,740
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)				$0				$0	$0		$4,394,888
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)				$0				$0	$0		$4,394,888
		Total PP&E	**$6,736,013**	**$375,225**	**$0**	**$7,111,238**	**$2,439,245**	**$178,991**	**$0**	**$2,618,235**	**$4,493,003**		
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)											
		Total						**$178,991**					

10		Transportation
8		Stores Equipment
8		Tools, Shop
8		Meas/Testing
8		Communication

Less: ***Fully Allocated Depreciation***
Transportation
Stores Equipment
Tools, Shop
Meas/Testi
Communication
Net Depreciation $178,991

Table 8 – 2023 Continuity schedule

Year **2023 IFRS**

			Cost				Accumulated Depreciation						
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**	AVG Gross Bal	AVG AccDep
12	1611	Computer Software (Formally known as Account 1925)	$183,454	$3,000	$0	$186,454	$155,809	$9,060	$0	$164,870	$21,584	$184,954	$160,340
N/A	1805	Land	$56,900	$0	$0	$56,900	$0	$0	$0	$0	$56,900	$56,900	$0
47	1820	Distribution Station Equipment <50 kV	$1,991,015	$0	$0	$1,991,015	$305,856	$36,200	$0	$342,056	$1,648,959	$1,991,015	$323,956
47	1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
47	1830	Poles, Towers & Fixtures	$912,258	$23,650	$0	$935,908	$382,561	$22,895	$0	$405,456	$530,452	$924,083	$394,009
47	1835	Overhead Conductors & Devices	$1,055,231	$0	$0	$1,055,231	$373,211	$17,387	$0	$390,598	$664,633	$1,055,231	$381,905
47	1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
47	1845	Underground Conductors & Devices	$2,219,216	$0	$0	$2,219,216	$914,336	$58,263	$0	$972,599	$1,246,617	$2,219,216	$943,468
47	1850	Line Transformers	$1,798,738	$97,400	$0	$1,896,138	$565,537	$43,548	$0	$609,085	$1,287,053	$1,847,438	$587,311
47	1855	Services (Overhead & Underground)	$438,796	$20,000	$0	$458,796	$128,449	$11,145	$0	$139,594	$319,202	$448,796	$134,022
47	1860	Meters	$0	$12,000	$0	$12,000	$0	$0	$0	$0	$12,000	$6,000	$0
47	1860	Meters (Smart Meters)	$435,887	$0	$0	$435,887	$253,504	$28,959	$0	$282,463	$153,424	$435,887	$267,983
8	1915	Office Furniture & Equipment (10 years)	$63,282	$1,200	$0	$64,482	$55,571	$1,448	$0	$57,019	$7,464	$63,882	$56,295
8	1915	Office Furniture & Equipment (5 years)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	1920	Computer Equipment - Hardware	$39,403	$1,500	$0	$40,903	$36,804	$1,643	$0	$38,447	$2,456	$40,153	$37,626
8	1935	Stores Equipment	$4,320	$0	$0	$4,320	$4,320	$0	$0	$4,320	$0	$4,320	$4,320
8	1940	Tools, Shop & Garage Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	1945	Measurement & Testing Equipment	$15,901	$0	$0	$15,901	$13,260	$1,162	$0	$14,422	$1,479	$15,901	$13,841
47	1995	Contributions & Grants	-$2,103,164	-$10,000	$0	-$2,113,164	-$570,984	-$51,204	$0	-$622,188	-$1,490,976	-$2,108,164	-$596,586
		Sub-Total	$7,111,238	**$148,750**	**$0**	**$7,259,988**	**$2,618,235**	**$180,507**	**$0**	**$2,798,742**	**$4,461,246**	$7,185,613	$2,708,489
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)				$0				$0	$0		$4,477,124
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)				$0				$0	$0		$4,477,124
		Total PP&E	**$7,111,238**	**$148,750**	**$0**	**$7,259,988**	**$2,618,235**	**$180,507**	**$0**	**$2,798,742**	**$4,461,246**		
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)											
		Total						**$180,507**					

10		Transportation
8		Stores Equipment
8		Tools, Shop
8		Meas/Testing
8		Communication

Less: *Fully Allocated Depreciation*
Transportation
Stores Equipment
Tools, Shop
Meas/Testi
Communication
Net Depreciation $180,507

2.2.2 Depreciation Expenses

In accordance with the July 17, 2012, letter from the Board on Regulatory accounting policy direction regarding changes to depreciation expense and capitalization policies and as such, CHEI has adopted the Kinetrics proposed useful lives and componentization on January 1, 2013. 1The revised methodology was included in CHEI's 2014 Cost of Service rate application EB-2013-0122.

Continuity Statements of the historical and forecasted depreciation expenses are presented on the next page and are filed in Excel format along with this application.

CHEI confirms that it has applied the half-year rule to compute the net book value of Property, Plant and Equipment, and General Plant in the rate base.[2] Under the half-year rule, acquisitions and investments made during the year are amortized, assuming they entered service at the year's mid-point.

CHEI's Depreciation rates and Capitalization Policy are presented below.

Capitalization Policy

CHEI's capitalization policy has not changed since its last Cost of Service in 2018.

All expenditures by the Corporation are classified as either capital or operating expenditures. The intention is to allocate costs across accounting periods to match those costs with current and future economic benefits appropriately. The amount to be capitalized is the cost to acquire or construct a capital asset, including any ancillary costs incurred to place a capital asset into its intended state of operation. CHEI does not currently capitalize interest on funds used for construction.

CHEI's adherence to the capitalization policy can be described as follows.

- ✓ Assets that are intended to be used on-going and expected to provide future economic benefit (generally considered to be greater than one year) will be capitalized.
- ✓ General Plant items with an estimated useful life greater than one year and valued at greater than $500 will be capitalized.
- ✓ Expenditures that create a physical betterment or improvement of the asset (i.e., there is a significant increase in the physical output or service capacity, or the useful life of the capital asset is extended) will be capitalized.
- ✓ With respect to vehicles, please note that CHEI does not own any vehicles.
- ✓ Maintenance services are contracted out.

Indirect overhead costs, such as general and administrative costs that are not directly attributable to an asset, are not, nor have they ever been capitalized.

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[1] MFR - Explanation of any deviations from the practice of depreciating significant parts or components of PP&E separately
[2] MFR – Identification of historical depreciation practice and proposal for test year. Variances from half- year rule.

Table 9 - Depreciation Rates

Account	Description	As of
1611	Computer Software (Formally known as Account 1925)	5
1820	Distribution Station Equipment <50 kV	55
1830	Poles, Towers & Fixtures	40
1835	Overhead Conductors & Devices	60
1845	Underground Conductors & Devices	35
1850	Line Transformers	40
1855	Services (Overhead & Underground)	40
1860	Meters	25
1860	Meters (Smart Meters)	15
1915	Office Furniture & Equipment (10 years)	10
1920	Computer Equipment - Hardware	5
1935	Stores Equipment	10
1940	Tools, Shop & Garage Equipment	10
1945	Measurement & Testing Equipment	10
1995	Contributions & Grants	40

Table 10 – Depreciation Expenses 2018 (App 2-C)

Year **2018** **IFRS**

Account	Description	Opening Regulatory Gross PP&E as at Jan 1	Less Fully Depreciated	Net for Depreciation	Additions	Total for Depreciation	Years	Depreciation Rate	Depreciation Expense	Depreciation Expense per Appendix 2-B	Variance [2]
		(a)	(b)	(c)	(d)	(e) = (c) + ½ x (d) [1]	(f)	(g) = 1 / (f)	(h) = (e) / (f)	Fixed Assets,	(m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$139,652	$85,406	$54,246	$1,081	$54,787	5.00	20.00%	$10,957	$11,005	-$48
1805	Land	$50,000	$0	$50,000	$6,900	$53,450	-		$0	$0	$0
1820	Distribution Station Equipment <50 kV	$1,949,403	$0	$1,949,403	$935	$1,949,871	55.00	1.82%	$35,452	$35,452	$0
1830	Poles, Towers & Fixtures	$796,246	$8,116	$788,130	$47,975	$812,118	40.00	2.50%	$20,303	$20,303	$0
1835	Overhead Conductors & Devices	$982,191	$0	$982,191	$20,181	$992,281	60.00	1.67%	$16,538	$16,538	$0
1845	Underground Conductors & Devices	$1,882,036	$0	$1,882,036	$17,800	$1,890,936	35.00	2.86%	$54,027	$54,027	$0
1850	Line Transformers	$1,215,794	$18,875	$1,196,919	$91,267	$1,242,553	40.00	2.50%	$31,064	$31,064	$0
1855	Services (Overhead & Underground)	$309,981	$0	$309,981	$20,819	$320,390	40.00	2.50%	$8,010	$8,010	$0
1860	Meters (Smart Meters)	$368,927	$0	$368,927	$17,552	$377,703	15.00	6.67%	$25,180	$25,180	$0
1915	Office Furniture & Equipment (10 years)	$54,220	$28,964	$25,257	$2,772	$26,643	10.00	10.00%	$2,664	$2,664	$0
1920	Computer Equipment - Hardware	$31,938	$26,623	$5,315	$0	$5,315	5.00	20.00%	$1,063	$1,271	-$208
1935	Stores Equipment	$4,320	$4,320	$0	$0	$0	10.00	10.00%	$0	$0	$0
1945	Measurement & Testing Equipment	$15,901	$4,281	$11,620	$0	$11,620	10.00	10.00%	$1,162	$1,162	$0
1995	Contributions & Grants	-$1,691,644	$0	-$1,691,644	-$60,245	-$1,721,766	40.00	2.50%	-$43,044	-$43,044	$0
	Total	$6,108,966	$176,584	$5,932,382	$167,037	$6,015,900			$163,376	$163,632	-$256

Table 11 – Depreciation Expenses 2019 (App 2-C)

Year **2019** **IFRS**

Account	Description	Opening Regulatory Gross PP&E as at Jan 1	Less Fully Depreciated	Net for Depreciation	Additions	Total for Depreciation	Years	Depreciation Rate	Depreciation Expense	Depreciation Expense per Appendix 2-B Fixed Assets,	Variance [2]
		(a)	(b)	(c)	(d)	(e) = (c) + ½ x (d) [1]	(f)	(g) = 1 / (f)	(h) = (e) / (f)	Column K	(m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$140,733	$85,406	$55,327	$2,988	$56,821	5.00	20.00%	$7,314	$7,314	$0
1805	Land	$56,900	$0	$56,900	$0	$56,900	-		$0	$0	$0
1820	Distribution Station Equipment <50 kV	$1,950,339		$1,950,339	$40,677	$1,970,677	55.00	1.82%	$35,830	$35,831	$0
1830	Poles, Towers & Fixtures	$836,105		$836,105	$2,500	$837,355	40.00	2.50%	$20,934	$20,934	$0
1835	Overhead Conductors & Devices	$1,002,372	$0	$1,002,372	$38,775	$1,021,759	60.00	1.67%	$17,029	$17,029	$0
1845	Underground Conductors & Devices	$1,899,836	$0	$1,899,836	$2,360	$1,901,016	35.00	2.86%	$54,315	$54,315	$0
1850	Line Transformers	$1,288,187	$10,295	$1,277,892	$68,080	$1,311,932	40.00	2.50%	$32,798	$32,798	$0
1855	Services (Overhead & Underground)	$330,799	$0	$330,799	$23,364	$342,481	40.00	2.50%	$8,562	$8,562	$0
1860	Meters (Smart Meters)	$386,479	$0	$386,479	$16,372	$394,665	15.00	6.67%	$26,311	$26,311	$0
1915	Office Furniture & Equipment (10 years)	$56,993	$31,696	$25,296	$909	$25,750	10.00	10.00%	$2,575	$2,575	$0
1920	Computer Equipment - Hardware	$31,939	$26,623	$5,315	$4,598	$7,614	5.00	20.00%	$1,523	$1,523	$0
1935	Stores Equipment	$4,320	$4,320	$0	$0	$0	10.00	10.00%	$0	$0	$0
1945	Measurement & Testing Equipment	$15,901	$4,281	$11,620	$0	$11,620	10.00	10.00%	$1,162	$1,162	$0
1995	Contributions & Grants	-$1,751,888	$0	-$1,751,888	-$11,125	-$1,757,451	40.00	2.50%	-$43,936	-$43,937	$0
	Total	$6,249,013	$162,622	$6,086,392	$189,497	$6,181,140			$164,417	$164,417	$0

Table 12 – Depreciation Expenses 2020 (App 2-C)

Year **2020** **IFRS**

Account	Description	Opening Regulatory Gross PP&E as at Jan 1	Less Fully Depreciated	Net for Depreciation	Additions	Total for Depreciation	Years	Depreciation Rate	Depreciation Expense	Depreciation Expense per Appendix 2-B Fixed Assets, Column K	Variance [2]
		(a)	(b)	(c)	(d)	(e) = (c) + ½ x (d) [1]	(f)	(g) = 1 / (f)	(h) = (e) / (f)		(m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$143,721	$125,911	$17,810	$628	$18,124	5.00	20.00%	$3,625	$3,625	$0
1805	Land	$56,900	$0	$56,900	$0	$56,900			$0	$0	$0
1820	Distribution Station Equipment <50 kV	$1,991,015		$1,991,015	$0	$1,991,015	55.00	1.82%	$36,200	$36,200	$0
1830	Poles, Towers & Fixtures	$830,490	$1,833	$828,656	$24,541	$840,927	40.00	2.50%	$21,023	$21,125	-$101
1835	Overhead Conductors & Devices	$1,041,146	$0	$1,041,146	$0	$1,041,146	60.00	1.67%	$17,352	$17,352	$0
1845	Underground Conductors & Devices	$1,902,196	$0	$1,902,196	$131,936	$1,968,163	35.00	2.86%	$56,233	$56,233	$0
1850	Line Transformers	$1,347,687	$18,875	$1,328,812	$159,101	$1,408,363	40.00	2.50%	$35,209	$40,138	-$4,929
1855	Services (Overhead & Underground)	$354,163	$0	$354,163	$31,633	$369,979	40.00	2.50%	$9,249	$9,250	$0
1860	Meters (Smart Meters)	$402,851	$0	$402,851	$8,943	$407,323	15.00	6.67%	$27,155	$27,155	$0
1915	Office Furniture & Equipment (10 years)	$57,901	$34,709	$23,192	$3,431	$24,908	10.00	10.00%	$2,491	$2,491	$0
1920	Computer Equipment - Hardware	$36,537	$27,053	$9,483	$617	$9,792	5.00	20.00%	$1,958	$1,958	$0
1935	Stores Equipment	$4,320	$4,320	$0	$0	$0			$0	$0	$0
1945	Measurement & Testing Equipment	$15,901	$4,281	$11,620	$0	$11,620	10.00	10.00%	$1,162	$1,162	$0
1995	Contributions & Grants	-$1,763,013	$0	-$1,763,013	-$240,151	-$1,883,089	40.00	2.50%	-$47,077	-$47,077	$0
	Total	$6,421,815	$216,983	$6,204,832	$120,679	$6,265,171			$164,581	$169,611	-$5,030

Table 13 – Depreciation Expenses 2021 (App 2-C)

Year **2021** **IFRS**

Account	Description	Opening Regulatory Gross PP&E as at Jan 1	Less Fully Depreciated	Net for Depreciation	Additions	Total for Depreciation	Years	Depreciation Rate	Depreciation Expense	Depreciation Expense per Appendix 2-B Fixed Assets, Column K	Variance [2]
		(a)	(b)	(c)	(d)	(e) = (c) + ½ x (d) [1]	(f)	(g) = 1 / (f)	(h) = (e) / (f)		(m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$144,349	$127,219	$17,130	$36,105	$35,183	5.00	20.00%	$7,037	$7,037	$0
1805	Land	$56,900	$0	$56,900	$0	$56,900			$0	$0	$0
1820	Distribution Station Equipment <50 kV	$1,991,015	$0	$1,991,015	$0	$1,991,015	55.00	1.82%	$36,200	$36,200	$0
1830	Poles, Towers & Fixtures	$855,031	$0	$855,031	$31,528	$870,794	40.00	2.50%	$21,770	$21,770	$0
1835	Overhead Conductors & Devices	$1,041,146	$0	$1,041,146	$2,085	$1,042,189	60.00	1.67%	$17,370	$17,370	$0
1845	Underground Conductors & Devices	$2,034,131	$0	$2,034,131	$5,085	$2,036,674	35.00	2.86%	$58,191	$58,191	$0
1850	Line Transformers	$1,506,788	$17,519	$1,489,269	$95,125	$1,536,832	40.00	2.50%	$38,421	$38,421	$0
1855	Services (Overhead & Underground)	$385,796	$0	$385,796	$30,000	$400,796	40.00	2.50%	$10,020	$10,020	$0
1860	Meters (Smart Meters)	$411,794	$0	$411,794	$12,093	$417,840	15.00	6.67%	$27,856	$27,856	$0
1915	Office Furniture & Equipment (10 years)	$61,332	$49,403	$11,929	$750	$12,304	10.00	10.00%	$1,230	$1,230	$0
1920	Computer Equipment - Hardware	$37,153	$28,438	$8,715	$750	$9,090	5.00	20.00%	$1,818	$1,818	$0
1935	Stores Equipment	$4,320	$4,320	$0	$0	$0			$0	$0	$0
1945	Measurement & Testing Equipment	$15,901	$4,281	$11,620	$0	$11,620	10.00	10.00%	$1,162	$1,162	$0
1995	Contributions & Grants	-$2,003,164	$0	-$2,003,164	-$20,000	-$2,013,164	40.00	2.50%	-$50,329	-$50,329	$0
	Total	$6,542,494	$231,180	$6,311,314	$193,519	$6,408,073			$170,745	$170,745	$0

Table 14 – Depreciation Expenses 2022 (App 2-C)

Year 2022 IFRS

Account	Description	Opening Regulatory Gross PP&E as at Jan 1	Less Fully Depreciated	Net for Depreciation	Additions	Total for Depreciation	Years	Depreciation Rate	Depreciation Expense	Depreciation Expense per Appendix 2-B Fixed Assets, Column K	Variance [2]
		(a)	(b)	(c)	(d)	(e) = (c) + ½ x (d) [1]	(f)	(g) = 1 / (f)	(h) = (e) / (f)		(m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$180,454	$127,219	$53,235	$3,000	$54,735	5.00	20.00%	$10,947	$10,947	$0
1805	Land	$56,900	$0	$56,900	$0	$56,900			$0	$0	$0
1820	Distribution Station Equipment <50 kV	$1,991,015	$0	$1,991,015	$0	$1,991,015	55.00	1.82%	$36,200	$36,200	$0
1830	Poles, Towers & Fixtures	$886,558	$0	$886,558	$17,400	$895,258	40.00	2.50%	$22,381	$22,382	$0
1835	Overhead Conductors & Devices	$1,043,231	$0	$1,043,231	$0	$1,043,231	60.00	1.67%	$17,387	$17,387	$0
1845	Underground Conductors & Devices	$2,039,216	$0	$2,039,216	$0	$2,039,216	35.00	2.86%	$58,263	$58,263	$0
1850	Line Transformers	$1,601,913	$17,519	$1,584,394	$108,825	$1,638,807	40.00	2.50%	$40,970	$40,970	$0
1855	Services (Overhead & Underground)	$415,796	$0	$415,796	$20,000	$425,796	40.00	2.50%	$10,645	$10,645	$0
1860	Meters (Smart Meters)	$423,887	$0	$423,887	$7,000	$427,387	15.00	6.67%	$28,492	$28,493	$0
1915	Office Furniture & Equipment (10 years)	$62,082	$49,403	$12,679	$1,200	$13,279	10.00	10.00%	$1,328	$1,328	$0
1920	Computer Equipment - Hardware	$37,903	$28,438	$9,465	$1,500	$10,215	5.00	20.00%	$2,043	$2,043	$0
1935	Stores Equipment	$4,320	$4,320	$0	$0	$0			$0	$0	$0
1945	Measurement & Testing Equipment	$15,901	$4,281	$11,620	$0	$11,620	10.00	10.00%	$1,162	$1,162	$0
1995	Contributions & Grants	-$2,023,164	$0	-$2,023,164	-$20,000	-$2,033,164	40.00	2.50%	-$50,829	-$50,829	$0
	Total	$6,736,013	$231,180	$6,504,833	$138,925	$6,574,296			$178,991	$178,991	$0

Table 15 – Depreciation Expenses 2023 (App 2-C)

Year 2023 IFRS

Account	Description	Opening Regulatory Gross PP&E as at Jan 1	Less Fully Depreciated	Net for Depreciation	Additions	Total for Depreciation	Years	Depreciation Rate	Depreciation Expense	Depreciation Expense per Appendix 2-B Fixed Assets, Column K	Variance [2]
		(a)	(b)	(c)	(d)	(e) = (c) + ½ x (d) [1]	(f)	(g) = 1 / (f)	(h) = (e) / (f)		(m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$183,454	$139,652	$43,802	$3,000	$45,302	5.00	20.00%	$9,060	$9,060	$0
1805	Land	$56,900	$0	$56,900	$0	$56,900			$0	$0	$0
1820	Distribution Station Equipment <50 kV	$1,991,015	$0	$1,991,015	$0	$1,991,015	55.00	1.82%	$36,200	$36,200	$0
1830	Poles, Towers & Fixtures	$903,958	$0	$903,958	$23,650	$915,783	40.00	2.50%	$22,895	$22,895	$0
1835	Overhead Conductors & Devices	$1,043,231	$0	$1,043,231	$0	$1,043,231	60.00	1.67%	$17,387	$17,387	$0
1845	Underground Conductors & Devices	$2,039,216	$0	$2,039,216	$0	$2,039,216	35.00	2.86%	$58,263	$58,263	$0
1850	Line Transformers	$1,710,738	$17,519	$1,693,219	$97,400	$1,741,919	40.00	2.50%	$43,548	$43,548	$0
1855	Services (Overhead & Underground)	$435,796	$0	$435,796	$20,000	$445,796	40.00	2.50%	$11,145	$11,145	$0
1860	Meters (Smart Meters)	$430,887	$0	$430,887	$7,000	$434,387	15.00	6.67%	$28,959	$28,959	$0
1915	Office Furniture & Equipment (10 years)	$63,282	$49,403	$13,879	$1,200	$14,479	10.00	10.00%	$1,448	$1,448	$0
1920	Computer Equipment - Hardware	$39,403	$31,938	$7,465	$1,500	$8,215	5.00	20.00%	$1,643	$1,643	$0
1935	Stores Equipment	$4,320	$4,320	$0	$0	$0			$0	$0	$0
1945	Measurement & Testing Equipment	$15,901	$4,281	$11,620	$0	$11,620	10.00	10.00%	$1,162	$1,162	$0
1995	Contributions & Grants	-$2,043,164	$0	-$2,043,164	-$10,000	-$2,048,164	40.00	2.50%	-$51,204	-$51,204	$0
	Total	$6,874,938	$247,114	$6,627,825	$143,750	$6,699,700			$180,507	$180,507	$0

2.2.3 Summary of Capital Expenditure and Contribution

The tables below illustrate the gross fixed additions resulting from the capital investment by CHEI from 2018 Board Approved to 2023 for the four OEB categories. CHEI notes that it does not have any work in progress (WIP) and confirms that the capital expenditures below represent in-service additions.

Table 16 – Gross Fixed Asset Additions – System Access

	2018 BA	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Projection	2023 Projection
Sub-Total System Access	$83,200	$79,865	$155,912	$238,671	$57,728	$331,300	$40,000
Planned per 2018 DSP		**$83,200**	**$135,000**	**$53,000**	**$53,000**	**$78,000**	
Contributed Capital	-$132,000	-$60,245	-11,125	-$240,151	-$20,000	-$80,000	-$10,000
Total System Access		$19,620	$144,787	-$1,480	$37,728	$251,300	$30,000

Table 17 – Gross Fixed Asset Additions – System Renewal

	2018 BA	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Projection	2023 Projection
Sub-Total System Renewal	$115,780	$143,563	$36,215	$77,545	$108,065	$112,225	$107,050
Planned per 2018 DSP		**$115,780**	**$20,000**	**$60,000**	**$62,000**	**$40,000**	
Contributed Capital		$0	0	0	0	0	0
Total System Renewal	$115,780	$143,563	$36,215	$77,545	$108,065	$112,225	$107,050

Table 18 – Gross Fixed Asset Additions – System Service

	2018 BA	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Projection	2023 Projection
Sub-Total System Service	$0	$0	$0	$11,532	$10,123	$6,000	$6,000
Planned per 2018 DSP		**0**	**0**	**0**	**0**	**0**	
Contributed Capital	$0	$0	0	0	0	0	0
Total System Service	0	0	0	11,532	10,123	6,000	6,000

Table 19 – Gross Fixed Asset Additions – General Plant

	2018 BA	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Projection	2023 Projection
Sub-Total General Plant	$5700	$3,854	$8,495	$4,676	$37,605	$5,700	$5,700
Planned per 2018 DSP		**$5,700**	**$5,700**	**$5,700**	**$5,700**	**$5,700**	
Contributed Capital		$0	0	0	0	0	0
Total System Access	$5,700	$3,854	$8,495	$4,676	$37,605	$5,700	$5,700

Summary of Capital Expenditures 2018-2021

- **System Access:** Expenditures for new services were in line with the expenditures planned per the 2018 DSP, except in 2020, when several subdivisions were completed. CHEI also expected 2022 to differ from the planned spending in 2018. This is a result of a new project called Project Central Park, which is expected to incur around $331,000 in total.
- **System Renewal**: Expenditures for system renewal were also in line with the planned the exception of unplanned expenditure of approximately 20K per year. Most of the unexpected spending is to replace transformers or elbows and inserts.
- **System Service**: CHEI hadn't planned to incur costs in this area. However, issues related to PCB caused unexpected spending in this category from 2020 and on.
- **General Plant**: Spending in the general service category is in line with what was planned and expected when CHEI put together its DSP plan in 2018.

The variances between planned expenditures in the 2018 DSP and actual spending are presented in the 2023 Distribution System Plan in appendix 2A.

2.2.4 Capital Additions: Year over Year Variance Analysis

CHEI has identified variance over the materiality threshold of $10,000. CHEI has chosen to explain its variance analysis based on capital additions.

Table 20 – Yearly Capital Additions by traditional grouping or account

	Acct #	Account Description	2018	2019	2020	2021	2022	2023
Distribution Plant	1611	Computer Software (Formally known as Account 1925)	$1,081	$2,988	$628	$36,105	$3,000	$3,000
Distribution Plant	1805	Land	$6,900	$0	$0	$0		$0
Distribution Plant	1820	Distribution Station Equipment <50 kV	$935	$40,677	$0	$0		$0
Distribution Plant	1830	Poles, Towers & Fixtures	$47,975	$2,500	$24,541	$31,528	$25,700	$23,650
Distribution Plant	1835	Overhead Conductors & Devices	$20,181	$38,775	$0	$2,085	$12,000	$0
Distribution Plant	1845	Underground Conductors & Devices	$17,800	$2,360	$131,936	$5,085	$180,000	$0
Distribution Plant	1850	Line Transformers	$91,267	$68,080	$159,101	$95,125	$196,825	$97,400
Distribution Plant	1855	Services (Overhead & Underground)	$20,819	$23,364	$31,633	$30,000	$23,000	$20,000
Distribution Plant	1860	Meters (Smart Meters)	$17,552	$16,372	$8,943	$12,093	$12,000	$12,000
		Subtotal	**$224,510**	**$195,116**	**$356,782**	**$212,021**	**$452,525**	**$156,050**
General Plant	1915	Office Furniture & Equipment (10 years)	$2,772	$909	$3,431	$750	$1,200	$1,200
General Plant	1915	Office Furniture & Equipment (5 years)	$0	$0	$0	$0		$0
General Plant	1920	Computer Equipment - Hardware	$0	$4,598	$617	$750	$1,500	$1,500
		Subtotal	**$2,772**	**$5,507**	**$4,048**	**$1,500**	**$2,700**	**$2,700**
	1995	Contributions & Grants	-$60,245	-$11,125	-$240,151	-$20,000	-$80,000	-$10,000
		Total Additions per year	**$167,037**	**$189,498**	**$120,679**	**$193,521**	**$375,225**	**$148,750**

Table 21 – Year over Year variances

	Acct #	Account Description	2018	2019	2020	2021	2022	2023
Distribution Plant	1611	Computer Software (Formally known as Account 1925)		$1,907	-$2,360	$35,476	-$33,105	$0
Distribution Plant	1805	Land		-$6,900	$0	$0	$0	$0
Distribution Plant	1820	Distribution Station Equipment <50 kV		$39,742	-$40,677	$0	$0	$0
Distribution Plant	1830	Poles, Towers & Fixtures		-$45,475	$22,041	$6,986	-$5,828	-$2,050
Distribution Plant	1835	Overhead Conductors & Devices		$18,594	-$38,775	$2,085	$9,915	-$12,000
Distribution Plant	1845	Underground Conductors & Devices		-$15,440	$129,575	-$126,851	$174,915	-$180,000
Distribution Plant	1850	Line Transformers		-$23,187	$91,021	-$63,977	$101,700	-$99,425
Distribution Plant	1855	Services (Overhead & Underground)		$2,546	$8,269	-$1,633	-$7,000	-$3,000
Distribution Plant	1860	Meters		$0	$0	$0	$0	$0
Distribution Plant	1860	Meters (Smart Meters)		-$1,180	-$7,429	$3,150	-$93	$0
General Plant	1915	Office Furniture & Equipment (10 years)		-$1,864	$2,522	-$2,681	$450	$0
General Plant	1920	Computer Equipment - Hardware		$4,598	-$3,981	$133	$750	$0
General Plant	1995	Contributions & Grants		$49,120	-$229,026	$220,151	-$60,000	$70,000

2021 1611-Computer Software increase of $35,476

Most of the increase is related to Honeywell Connexo NetSense Software for 28K. Connexo NetSense integrates data, workflows, and business processes, making integration more cost-effective. Connexo NetSense delivers what utilities look for in a head-end system: simple deployment and operation with visibility into network activity and health to protect against outages.

2019 1820-Distribution Station Equipment <50 kV increase of $39,742

Most of the increase is related to implementing a Supervisory Control and Data Acquisition (SCADA) system. SCADA systems are critical as it helps maintain efficiency by collecting and processing real-time data.

2020 1830-Poles, Towers & Fixtures increase of $22,041

The increase is the replacement of 3 poles in that particular year that wasn't planned.

2020 1845-Underground Conductors & Devices increase of $129,575

2020 1845-Underground Conductors & Devices increase of $91,021

The increase in the above accounts is due to two subdivisions being energized. Versailles III and Patenaude East Subdivision Phase II.

2022 1850-Line Transformers increase of $174,915

2022 1850-Line Transformers increase of $101,700

The increase in the above accounts is a result of two new projects planned for 2022. The first being a new subdivision (Melanie Construction Phase III).and the second being a commercial project (Central Park). These costs are based on traditional costs that required to provide electricity to new development.

Details of capital expenditures for costs above the threshold and costs which deviated from the last DSP are presented throughout the DSP, more specifically in section 4 of the DSP.

2.3. DERIVATION OF THE WORKING CAPITAL ALLOWANCE

CHEI's working capital allowance was determined by taking the sum of Cost of Power and controllable expenses (i.e., Operations, Maintenance, Billing and Collecting, Community Relations, Administration and General) and applying an allowance of 7.5%. The table below shows CHEI's calculations in determining its Allowance for Working Capital. The increase in OM&A is discussed in detail in exhibit 4. Other components of the Working Capital Allowance are discussed below. The Working Capital Allowance has decreased by $11,422 over the 2018 Board Approved. The decrease from the 2018 Board Approved to the Test Year 2023 is due to the reduction in Power Supply Expenses.

Table 22 – Trend in Working Capital Allowance

Expenses for Working Capital	Last Board Approved	2018	2019	2020	2021	2022	2023	Var from 2018
Eligible Distribution Expenses:								
3500- Operation	36,569	36,569	44,096	49,131	44,455	45,923	$47,439	$10,870
3550- Maintenance	53,115	53,115	38,679	62,243	46,375	47,905	$49,486	-$3,629
3650-Billing and Collecting	199,982	199,982	219,757	214,452	217,108	236,739	$244,306	$44,324
3700-Community Relations	5,150	5,150	4,628	4,445	3,300	3,409	$3,521	-$1,629
3800-Administrative Expenses	385,155	387,155	391,298	408,195	391,128	405,812	$408,405	$23,250
								-$2,000
								$0
Total Eligible Distribution Expenses	$681,971	$681,971	$698,458	$738,467	$702,365	$739,788	$753,157	$71,186
3350-Power Supply Expenses	$3,525,627	$3,148,742	$3,512,283	$4,487,602	$4,487,602	$3,199,114	$3,293,006	-$232,621
Total Expenses for Working Capital	$4,207,598	$3,830,713	$4,210,741	$5,226,070	$5,189,967	$3,938,902	$4,046,164	-$161,434
Working Capital factor	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	0.0%
Total Working Capital	**$315,570**	**$287,303**	**$315,806**	**$391,955**	**$389,248**	**$295,418**	**$303,462**	**-$12,108**

2.3.1 Deemed Allowance vs Lead Lag

CHEI has used the 7.5% Allowance Approach to calculate its Allowance for Working Capital. This was done per the letter issued by the Board on June 03, 2015, for a rate of 7.5%

CHEI is not proposing to use a lead-lag study to determine its Working Capital Allowance and has chosen to follow the Board's June 3, 2015, letter, which provided two options for the calculation of the allowance for working capital:

(1) The 7.5% allowance approach; or

(2) The filing of a lead/lag study.

CHEI notes that it has not previously been directed by the Board to undertake a lead/lag study.

Increased Distribution Expenses

CHEI's 2023 Test Year operating costs are projected to be $753,157, representing an increase of $71,186 or 10.4% from its 2018 Board Approved costs. Details are introduced in Table 1 below. Explanations and details are presented in the next section and throughout this exhibit.

Table 23 – 2023 OM&A vs 2018 Board Approved OM&A

	2018 Board Approved	2023	Variance from 2018BA
Operations	$36,569	$47,439	$10,870
Maintenance	$53,115	$49,486	-$3,629
Subtotal	**$89,684**	**$96,924**	**$7,240**
Billing and collecting	$199,982	$244,306	$44,324
Community Relations	$5,150	$3,521	-$1,629
Administrative and General+LEAP	$387,155	$408,405	$21,250
Subtotal	**$592,287**	**$656,233**	**$63,946**
Total	**$681,971**	**$753,157**	**$71,186**
%Change (Test Year vs Last Rebasing Year			10.4%

2.3.1 Derivation of the Cost of Power

The components of CHEI's cost of power are summarized below and detailed in several tables illustrated over the following pages. CHEI confirms that it used the most up to date inputs and guidelines to determine its cost of power.

Table 24 – 2023 Cost of Power

Component	$	Calculated based on loss adjusted or non-loss adjusted
4705 -Power Purchased	$3,026,090	Loss adjusted
4707- Global Adjustment	$227,349	Loss adjusted
4708-Charges-WMS	$104,839	Loss adjusted
4714-Charges-NW	$300,773	Loss adjusted
4716-Charges-CN	$209,729	Loss adjusted
4750-Charges-LV	$136,375	Non-loss-adjusted
4751-IESO SME	$17,166	Customer Count
Misc A/R or A/P	-$729,316	
TOTAL	**$3,293,006**	

Commodity and Global Adjustment non-RPP (4705- Power Purchased and 4707 Global Adjustment)

CHEI attests that the Cost of Power is determined by the split between RPP and non-RPP customers based on actual data, using the most current RPP price and current UTR. CHEI calculated the cost of power for the 2022 Bridge Year and the 2023 Test Year based on the results of the load forecast discussed in detail in Exhibit 3. The commodity prices used in the calculation were published in the Board's "Regulated Price Plan - Price Report May 01 to April 30, 2022". Should the Board issue a revised Regulated Price Plan Report before the Board's Decision in the application, CHEI will update the electricity prices in the forecast.

The Commodity share of the Cost of Power is calculated in the same manner as has been previously approved by the OEB in CHEI's previous Cost of Service application and other applications.

The sale of energy is a flow-through revenue, and the cost of power is a flow-through expense. Energy sales and the cost of power expense are presented in the table below. CHEI records no profit or loss from the flow-through energy revenues and costs. Any temporary variances are included in the RSVA account balances.

		2023 Test Year	RPP			2023 Test Year	non-RPP		Total
Electricity Commodity	**Units**	Volume	Rate	$		Volume	Rate	$	$
Class per Load Forecast				-					
Residential	kWh	21,806,912		2,257,888					2,257,888
General Service < 50 kW	kWh	5,002,578		517,967					517,967
General Service > 50 to 4999 kW	kWh	1,078,043		111,621		3,204,602		108,155	219,776
Unmetered Scattered Load	kWh	-		-		100,857		3,404	3,404
Street Lighting	kWh	261,309		27,056					27,056
SUB-TOTAL		28,148,842		2,914,531		3,305,459		63,630	**$ 3,026,090**
Global Adjustment non-RPP	**Units**	Volume	Rate	$		Volume	Rate	$	Total
Class per Load Forecast									
Residential	kWh							-	
General Service < 50 kW	kWh							-	
General Service > 50 to 4999 kW	kWh							272,968	
Unmetered Scattered Load	kWh							8,591	
Street Lighting	kWh							-	
SUB-TOTAL								227,349	**$227,349**

**Regulated Price Plan Price Report November 1, 2021, to October 31, 2022 Ontario Energy Board Oct 21,2021*

Transmission Network and Connection Charges (4714-Charges-NW and 4716-Charges-CN)

Electricity distributors are charged for transmission costs at the wholesale level and subsequently pass these charges on to their distribution customers through the Retail Transmission Service Rates (RTSRs). For each distribution rate class, there are two RTSRs:

- RTSR Network charge - recovers the Uniform Transmission Rates (UTR) wholesale network service charge
- RTSR Connection charge - recovers the UTR wholesale line and transformation connection charges.

The table below summarizes the projected transmission network and connection expenses, applying the proposed rates to the 2023 load forecast kWh and kW volumes:

Table 25 - Transmission Network and Connection Expenses

Transmission - Network	Units	Volume	Rate	$
Class per Load Forecast				
Residential	kWh	21,806,912	0.0098	213,001
General Service < 50 kW	kWh	4,962,824	0.0089	44,068
General Service > 50 to 4999 kW	kW	11,425	3.5930	41,049
Unmetered Scattered Load	kWh	100,056	0.0089	888
Street Lighting	kW	652	2.7098	1,767
SUB-TOTAL				300,773

Transmission - Connection	Units	Volume	Rate	$
Class per Load Forecast				
Residential	kWh	21,806,912	0.0069	150,770
General Service < 50 kW	kWh	4,962,824	0.0060	29,561
General Service > 50 to 4999 kW	kW	11,425	2.4144	27,584
Unmetered Scattered Load	kWh	100,056	0.0060	596
Street Lighting	kW	652	1.8664	1,217
SUB-TOTAL				209,729

**Rates are based on Decision and Rate Order EB-2021-0276 2022 Uniform Transmission Rates issued December 16,2021*

The transmission network charges, included in the Cost of Power for the Test Year 2023, are projected at $300,773, and the connection charges are projected at $209,729. The Rates are applied to the 2023 Load Forecast to determine the amount included in the Cost of Power.

Wholesale Market Service Charges & Capacity Based Recovery Charges (4708-Charges-WMS)

On December 17, 2019, the OEB released Decision and Order for the Wholesale Market Service (WMS) effective January 1, 2020. The Board's decision is summarized as follows:

- The WMS rate used by rate-regulated distributors to bill their customers shall be $0.0030 per kilowatt-hour, effective January 1, 2020.
- For Class B customers, a Capacity-based Recovery (CBR) component of $0.0004 per kilowatt-hour shall be added to the WMS rate for a total of $0.0034 per kilowatt-hour.
- For Class A customers, distributors shall bill the actual CBR costs to Class A customers in proportion to their contribution to the peak.

In compliance with this order, CHEI has applied the Board-approved rate of $0.0034/kWh to its' 2023 Load Forecast to include $80,646 for WMS and $10,753 in Class B CBR in its' Cost of Power projections as illustrated in the table below:

Table 26- Wholesale Market and CBR

Wholesale Market Service	**Units**		**Volume**	**Rate**	**$**
Class per Load Forecast					
Residential	kWh		21,806,912	0.0030	65,421
General Service < 50 kW	kWh		4,962,824	0.0030	14,888
General Service > 50 to 4999 kW	kWh		11,425	0.0030	34
Unmetered Scattered Load	kWh		100,056	0.0030	300
Street Lighting	kWh		652	0.0030	2
SUB-TOTAL					$80,646
Class B CBR	**Units**		Volume	Rate	$
Class per Load Forecast					
Residential	kWh		21,806,912	0.0004	8,723
General Service < 50 kW	kWh		4,962,824	0.0004	1,985
General Service > 50 to 4999 kW	kW		11,425	0.0004	5
Unmetered Scattered Load	kWh		100,056	0.0004	40
Street Lighting	kW		652	0.0004	0
SUB-TOTAL					$10,753
Total					$91,398

**DECISION AND ORDER EB-2020-0276 In the matter of regulatory charges effective January 1, 2021, for the Wholesale Market Services rate and the Rural or Remote Electricity Rate Protection charge issued December 10, 2020*

Rural or Remote Electricity Protection Rate (RRRP) Charges

On December 17, 2019, the OEB released Decision and Order for the Rural or Remote Electricity Protection Rate (RRRP) effective January 1, 2020. The Board's decision is summarized as:

- The RRRP rate used by rate-regulated distributors to bill their customers shall be $0.0005 per kilowatt-hour, effective January 1, 2020.

In compliance with this order, CHEI has applied the Board Approved $0.0005/kWh to its' 2023 Load Forecast to include $13,414 in its' Cost of Power as illustrated in the table below:

Table 27 – Rural or Remote Electricity Rate Protection (4708-Charges-RRRP)

RRRP	Units		Volume	Rate	$
Class per Load Forecast					
Residential	kWh		21,806,912	0.0005	10,903
General Service < 50 kW	kWh		4,962,824	0.0005	2,481
General Service > 50 to 4999 kW	kW		11,425	0.0005	6
Unmetered Scattered Load	kWh		100,056	0.0005	50
Street Lighting	kW		652	0.0005	0
SUB-TOTAL					$13,441

**DECISION AND ORDER EB-2020-0276 In the matter of regulatory charges effective January 1, 2021, for the Wholesale Market Services rate and the Rural or Remote Electricity Rate Protection charge issued December 10, 2020*

Smart Meter Charge

On March 1, 2018, the Ontario Energy Board (OEB) approved the application by the Independent Electricity System Operator (IESO), in its capacity as the Smart Metering Entity (SME), for a smart metering charge (SMC) for the 2018-2022 period, for a new SMC of $0.57 per smart meter (Residential and General Service <50 kW) per month. The proposed rate remains at $0.57 per the OEB guidance provided on March 23, 2018.

In compliance with this order, CHEI has applied the Board Approved rate of $0.57 per month for the forecasted Residential and General Service<50kW customers for Test Year 2021 and included the projected amount of $17,166 in its' Cost of Power as illustrated below:

Table 28 - Smart Meter Entity (4751-IESO SME)

Smart Meter Entity Charge		Customers	Rate	$
Class per Load Forecast				
Residential		2345	$0.57	$16,040
General Service < 50 kW		165	$0.57	$1,126
SUB-TOTAL				$17,166

The table below shows the derivation of proposed retail rates for Low Voltage ("LV") service. The 2023 estimates of total LV charges were calculated based on the last three years of actual charges from Hydro One.

The 2023 projected LV charges are based on an internal review of the historical charges.

CHEI notes that a 5-year average ($136,674), the four-year average ($136,375), and the three-year average (136,375) are all within $150 of each other. Therefore, CHEI opted to use an average of the last three years as a projection of its 2023 LV charges.

The projections were allocated to customer classes, according to each class share of projected Transmission-Connection revenue, per Board policy. The resulting LV charges for each class were divided by the applicable 2023 volumes from the load forecast, as presented in Exhibit 3.

Current LV revenues are recovered through a separate rate adder and are not embedded within the approved Distribution Volumetric rate. LV rates appear on a distinct line item on the proposed schedule of rates.

Table 29 – Proposed LV Charges (4750-Charges-LV)

Low Voltage Charges - Historical and Proposed LV Charges							
	2016	**2017**	**2018**	**2019**	**2020**	**4-year avg**	**3-year avg**
4075-Billed - LV	$49,679	$48,531	$93,723	$92,340	$93,743	$82,084	$93,269
4750-Charges - LV	$135,225	$137,568	$153,633	$142,130	$113,363	$136,674	$136,375
1551 LV Charges	*$98,816*	*$32,624*	*$35,668*	*$40,376*	*$27,402*	*$193,161*	

Low Voltage Charges Rate Rider Calculations					
	PROPOSED LOW VOLTAGE CHARGES & RATES				
Customer Class Name	**% Allocation**	**Charges**	**Not Uplifted Volumes**	**Rate**	**per**
Residential	71.89%	98,038	20,126,172	$0.0049	kWh
General Service < 50 kW	14.10%	19,222	4,617,010	$0.0042	kWh
General Service > 50 to 4999 kW	13.15%	17,937	11,425	$1.5700	kW
Unmetered Scattered Load	0.28%	388	93,084	$0.0042	kW
Street Lighting	0.58%	791	652	$1.2136	kW
TOTAL	**100.00%**	$136,375	**24,848,343**		

Table 29 – Proposed LV Charges (4750-Charges-LV) (Cont'd)

Customer		2023		
Class Name		Volume	Rate	Amount
Residential	kWh	20,126,172	$0.0049	$98,618
General Service < 50 kW	kWh	4,617,010	$0.0042	$19,391
General Service > 50 to 4999 kW	kW	11,425	$1.5700	$17,937
Unmetered Scattered Load	kW	93,084	$0.0042	$391
Street Lighting	kW	652	$1.2136	$791
TOTAL		**24,848,343**		**$136,375**

2.4. DISTRIBUTION SYSTEM PLAN FOR SMALL UTILITIES

Per section 2.2.2.1 of the filing requirements, CHEI has filed its 2023 DSP as a stand-alone document, included in Appendix 2A of this exhibit.

The DSP describes how CHEI's proposed capital investments for the 2023-2027 period are informed by its asset management process and continuous internal asset condition monitoring and assessment.

As a preamble to the DSP, CHEI's Capital Expenditure Checklist, shown in the table below, highlights areas of change that affect the utility's capital investment and overall plan.

Table 30 – Capital Expenditure Checklist

Area to Address	Capital Investment Required?
Capacity Issues	No
Reliability	No
Safety	No
Service Quality	No
Efficiency Assessment & Unit Cost Metrics	No
Regional Planning	No
Renewable Energy Generation / DER	No
Major Asset Replacement	No
New ACM	No
Customer Growth	No
Asset Condition	No
Other	No

Capacity Issues

CHEI installed a new substation rated at 10 MVA / 13.3 MVA (ONAN/ ONAF) in 2017 while keeping the old substation to act as a backup in the event of an MS transformer failure and there not being supply capability from Hydro One. The new substation and redundancy plan addressed any concerns relating to capacity issues; therefore, in this Capital Expenditure Plan period, the LDC is proposing no investment is required for capacity.

System Reliability & Performance

The table below summarizes all causes of power interruptions experienced by CHEI customers for the period 2018 to 2020:

Table 31 – All Causes of Power Interruptions (2018-2020)

		2016		2017		2018		2019		2020	
Cause Code	Description	# of Customer Interruption	# Customers Hours	# of Customer Interruption	# Customers Hours	# of Customer Interruption	# Customers Hours	# of Customer Interruption	# Customers Hours	# of Customer Interruption	# Customers Hours
0	Unknow/Other	0	0	0	0	0	0	1	2.75	2	7.5
1	Scheduled Outage	485	88	10	10	113	896	120	32	20	60
2	Loss of Supply	10622	53070	2175	2175	6830	63651	0	0	0	0
3	Tree Contact	0	0	0	0	0	0	0	0	0	0
4	Lightning	0	0	0	0	0	0	0	0	0	0
5	Defective Equipment	0	0	5	14	13	473.25	6	3	2	4.5
6	Adverse Weather	0	0	0	0	2	2	1	1.75	0	0
7	Adverse Environment	0	0	0	0	0	0	0	0	0	0
8	Human Element	0	0	0	0	0	0	0	0	0	0
9	Foreign Interference	0	0	0	0	0	0	1	3	1	2

As illustrated in the table above, most power interruptions over the historical period have been caused by loss of supply. Scheduled outages are, for the most part, related to asset replacement. No major events have occurred in the past five years.

Safety - Operational Effectiveness Indicators

CHEI has consistently met all safety requirements and indicators; therefore, no issues or capital investments are required to meet safety targets.

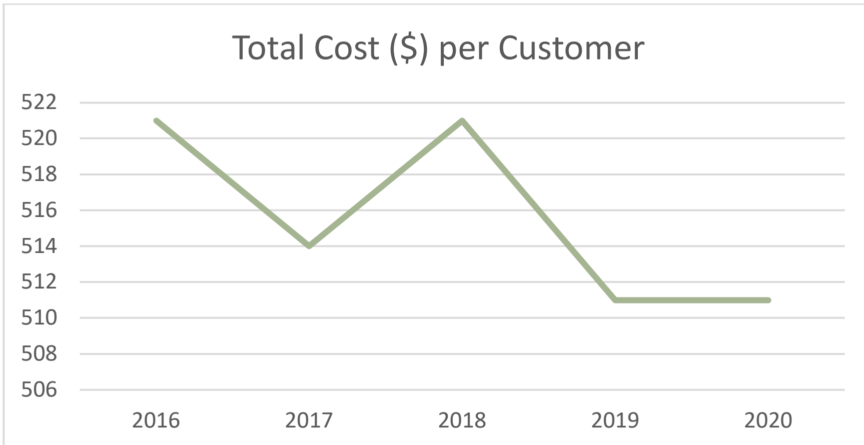
Efficiency Assessment & Unit Cost Metrics

CHEI has been assigned group 1 in terms of efficiency – i.e., the utility having actual costs 25% below the predicted modeled costs. Group 3 is rated as the most efficient group. The utility's costs fall below the average cost range of all Ontario electricity distributors. Using the benchmarking forecast model, CHEI expects to remain in Group 1's efficiency performance. Will being in group 1, CHEI is still improving its efficiency, with 2023 proposed costs predicted to be 70.1% lower than the model's predicted costs.

Cost per Customer

The chart below illustrates CHEI's "Cost per Customer" over the five years 2016 to 2020:

Table 32 – Total Cost per Customer per Year



The table below summarizes the change in "Cost per Customer" over the five years. As can be seen, the utility is working towards reducing its costs per customer. The progress towards achieving lower rates was interrupted in the utility's last cost of service and was, for the most part, related to the addition of the transformer station.

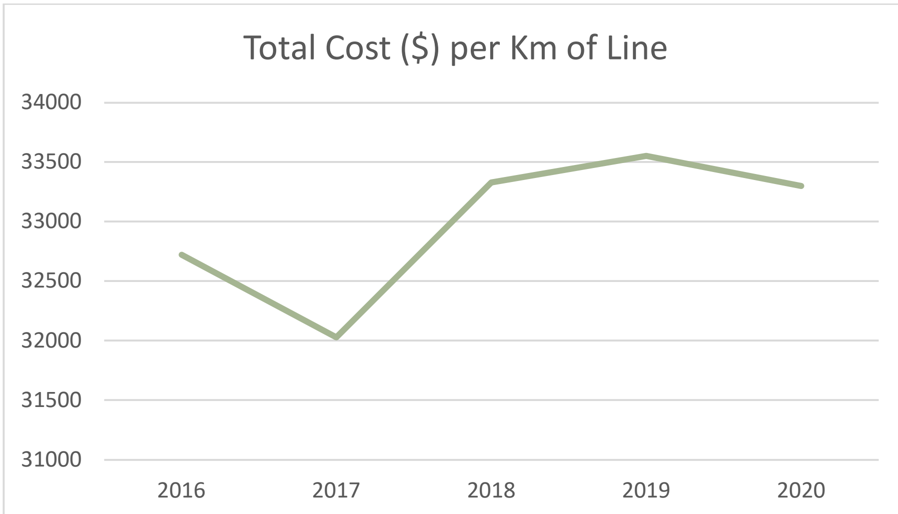
Like most distributors in the province, CHEI has experienced increases in its total operating costs required to deliver quality and reliable services to customers. Investments in new information systems technology, cyber-security, and labour cost adjustments for inflation for employees, as well as the renewal of the distribution system, have all contributed to increased operating and capital costs.

CHEI's customer growth rate for its territory is considered to be relatively steady at approximately 1% per year. The utility will continue to seek innovative solutions to help ensure cost per customer remains competitive and within acceptable limits to its customers.

Cost per Kilometer of Line

The chart below illustrates CHEI's "Cost per Kilometer of Line" over the five years 2016 to 2020:

Table 33 – Total Cost per Kilometer of Line



The table below summarizes the change in "Cost per Kilometer of Line" over the five years. The kilometers of line have not changed in the past. As the utility adds or replaces aged capital assets, the cost per km of lines increases accordingly.

CHEI will continue to replace distribution assets and has provision for replacement of assets based on its replacement process and age as described in the LDC's capital investment plan for 2023-2027.

Regional Planning

CHEI participates in Hydro One's regional needs and assessment planning meetings and reports. (Appendix 2-B) There are no capacity issues or need for regional planning investment in the service area that would affect CHEI.

Renewable Energy Generation / DER

Applications from Renewable Generators Over 10 kW for Connection

The FIT-size generator connection application process for CHEI customers requires the involvement of HONI. The application process includes an internal review of applications. CHEI also requires approval from HONI for projects greater than 10kW for connection capacity, as HONI is the Host Distributor. The LDC is unaware of any upstream capacity constraints at the HONI-owned TS in Chesterville relating to the CHEI supply feeders.

Net Metering

CHEI has not received any requests for the connection of “net metering” in its service territory. Based upon the above information, CHEI does not expect to reach the current available capacity for renewable generation in the near future (i.e., over the 5-year forecast horizon).

Smart Grid

At this time, there is no capital investment for Renewable Generation or DER included in CHEI’s forecasted capital expenditure plan for 2023-2027.

Major Asset Replacement

No significant assets (e.g., substation) are scheduled for replacement due in the DSP period 2023-2027.

Advanced Capital Module (ACM)

For the Capital Plan period 2023-2027, CHEI is not requesting an ACM to fund a capital project.

Customer Growth

No customer growth outside of the usual trend will present capacity or loading issues during the 5-year DSP period of 2023-2027.

Asset Condition Assessment

CHEI’s asset base is small and manageable enough that a formal Asset Condition Assessment (ACA) does not need to be conducted. CHEI’s asset base comprises substations, transformers, substation load switches, switchgear, pole-mount transformers, pad-mount transformers, and poles. CHEI, with the input of its 3rd party capital work contractor Sproule Powerline Construction Ltd, ultimately decides on the replacement of assets that are at risk of failing or are in poor health. A minimum number of overall replacements are required throughout the 5-year plan to sustain asset performance at current levels. Inspections and testing programs are designed to identify poor health poles and transformers for proactive replacement before failure.

Approximately 432 primarily wood-type poles support the overhead distribution system. CHEI completes system patrols regularly. The patrol includes a visual inspection of the poles looking for visible signs of damage or a leaning pole. Poles are tested every three to four years. Currently, the results are used to provide input into the capital plan primarily for the following year as well as going into a cost-of-service year. Poles flagged as problematic are planned for replacement. CHEI continues to develop the improved pole testing process.

Other

No other issues were identified for capital investment.

Capitalization of overhead

Indirect overhead costs, such as general and administrative costs that are not directly attributable to an asset, are not, nor have they ever been capitalized. (As such, Appendix 2-D is not applicable in this case)

Costs of eligible investments for distributors

CHEI attests that it has not included any costs or Investments to Connect Qualifying Generation Facilities in its capital costs or its Distribution System Plan.

As such, details of any capital contributions made or forecast to be made to a transmitter concerning a Connection and Cost Recovery Agreement are not applicable in this case.

CHEI is not considering incremental conservation initiatives to defer or avoid future infrastructure projects as part of distribution system planning processes, nor is it planning on applying for funding through distribution rates to pursue activities such as energy efficiency programs, demand response programs, energy storage programs, etc. Lastly, CHEI is not considering a generation facility.

New policy options for the funding of capital

CHEI is not proposing any unique or different approach to funding its capital expenditure

Addition of ICM assets to rate base

CHEI has not applied to recover investments through the OEB's Incremental Capital Module. And as such, CHEI does not need to reconcile the balance in account 1508 with rate base amounts.

Transmission or high voltage assets

Per ANSI standard C84.1-1989, "Low" voltage is described as 600V and below. "Medium" voltage is 2.4kV through 69kV. "High" voltage is 115kV through 230kV and "Extra-High" voltage is 345kV to 765kV, while "Ultra-high" voltage is 1.1MV. The higher voltage of the transformer (primary or secondary) is the voltage on which the transformer is designated.

CHEI currently operates two 44KV which technically could be classified as "high-voltage which are still expected to be treated as distribution assets. CHEI confirms that it does not have any transmission assets or distribution assets which are treated differently than its previous application.

APPENDICES

List of Appendices

Appendix 2A	Distribution System Plan

Cooperative Hydro Embrun Inc.

Distribution System Plan

Date Due

January 2022

Submitted by

Benoit Lamarche

TABLE OF CONTENTS

1 INTRODUCTION

This Distribution System Plan (DSP, "The Plan") has been prepared by Cooperative Hydro Embrun Inc. (CHEI). The DSP follows the chapter and section headings set out in Filing Requirements for Electricity Distribution Rate Applications - 2022 Edition for 2023 Rate Applications – For Small Utilities Chapter 5A Small Utilities Distribution System Plan issued on December 16, 2021.

CHEI's DSP is an integrated document supporting cost-effective planning that ensures efficiency, reliability, sustainability, and value for its customers. The DSP documents the practices, policies, and processes that are currently in place. These processes ensure that investment decisions support CHEI's desired outcomes cost-effectively and provide value to the customer. CHEI is committed to adhering to its DSP to provide valued outcomes to its customers. Electricity distributors are capital intensive, and prudent capital investments and maintenance plans are essential to ensure the sustainability and reliability of the distribution network.

The DSP reflects CHEI's integrated approach to planning, prioritizing, and managing assets and includes regional planning and local stakeholder consultations. CHEI has completed this DSP focusing on customer preferences and operational effectiveness while achieving optimal value for capital spending.

CHEI has organized the required information using the section headings in the DSP Filing Requirements. Investment projects and activities have been grouped into one of the four OEB-defined investment categories: System Access, System Renewals, System Service, and General Plant.

The DSP covers a historical period from 2018 to 2021, the transition year is 2022, and the test year is 2023, with the forecast years being 2023 to 2027. CHEI notes that the information contained in this plan is current is based on actual costs as of October 2021, and the projections for capital expenditures are based on data collected as of December 31, 2021.

1.1 Utility Overview

CHEI is an electricity distributor licensed by the OEB. Per its Distribution License ED-2002-0493, CHEI provides electricity distribution services in the Town of Embrun, about 37 km southeast of Ottawa. CHEI is responsible for maintaining distribution and infrastructure, servicing 2,463 customers across its service area spanning a distribution service territory of approximately five square kilometers. CHEI is incorporated under the Co-operative Corporations Act and is 100% owned by its members. The utility is managed by a Board of Directors appointed by the members. CHEI has three employees: a General Manager, an Administrative Coordinator, and a Collection Agent-Customer Service representative.

The weather is characterized by cold winters with snow and cold temperatures. Embrun has a semi-continental climate, with a warm, humid summer and a very cold winter.

Winters in Embrun are severe. Snow depths of greater than 1 cm are seen on about 120 days each year, and freezing rain is not uncommon in the winter. Minimum average temperatures in January are about -15 degrees C., and in summer, the maximum average temperature is about 26 degrees C.

CHEI earns revenue by delivering electric power to the homes and businesses in the service territory. The rates charged for this and the performance standards that the energy delivery system must meet are regulated by the Ontario Energy Board.

CHEI is an embedded utility in Hydro One Distribution's service territory and, as such, is supplied power from Hydro One's Chesterville Transformer Station at 44kV.

CHEI receives power from Hydro One Networks Inc. ("Hydro One") at 44 kV and steps the voltage down to 8.32kV at its' both Municipal Station (MS). The MS as of TI rated at 7.5 MVA/ 10MVA (ONAN/ ONAF) act as a backup in the event of T2 failure, T2 rated at 10 MVA / 13.3 MVA (ONAN/ ONAF) built-in 2017. From these MS, it delivers power to its customers via four feeders emanating from its' MS. CHEI earns revenue by providing electric power to the homes and businesses in the service territory. The rates charged for this and the performance standards that the energy delivery system must meet are regulated by the Ontario Energy Board.

The table below shows CHEI's principal characteristics, which drive the DSP.

Table 1 – CHEI's System Summary

	2020	**Supporting information**
Maximum Winter Monthly Peak	6135	December 16, 2020, at 6:00 pm
Maximum Summer Monthly Peak	7223	July 9, 2020, at 5:00 pm
Maximum Winter Monthly Peak	6135	December 16, 2020, at 6:00pm
(With embedded Gen)		
Maximum Summer Monthly Peak	7223	July 9, 2020, at 5:00 pm
(With embedded Gen)		
Service Area (Urban)	5 SQ.KM	
km of line	37	
Total Customer (metered)		**2020 Usage kWhs (Not adjusted)**
Residential	2212	21,302,214
GS<50	162	4,285,367
GS50-4999	9	3,022,445
Total Number of Meters Accounts	2383	28,610,026.00
Total, unmetered connections		**2020 Usage kWhs (Not adjusted)**
USL	17	93,084
Sentinel	-	-
Street Lighting	582	212,836
Total Number of USL Connections	599	305,920.00
		2020 Usage kWhs (Not adjusted)
Annual Metered Consumption		28,915,946

Annual Generation (MicroFit)	101,329.00	**kWhs** Generated in 2020
		13 MicroFit Customers
Number of Substation	2	
Wholesale Meter Points	1	
Poles	345	
Primary Lines (km)		
Overhead	18	
Underground	19	
Transformers		
Overhead (Pole mount)	144	
Underground (Pad mount)	113	
Switches Load Break 4.8 Kv	9	

1.2 Investment Category

In developing its long-term DSP, CHEI's objective is to make timely investments in infrastructure to ensure its distribution system continues to deliver power at the quality and reliability levels required by its customers. Detail on the forecast capital expenses can be seen in Appendix B.

CHEI tracks its capital spending in the USoA and the RRFE categories (System Access, System Renewal, System Service, and General Plant).

Table ES-1 below provides the Historical Investments CHEI has made between 2018 and projected for 2022. Capital projects are detailed in section 4 of this report.

Table 2 - Historical Capital Investments by Year (Table ES-1)

CATEGORY	**2018**			**2019**		
	Plan	**Actual**	**Var**	**Plan**	**Actual**	**Var**
	$ '000		%	*$ '000*		%
System Access	$34,500	$79,865	131.5%	$135,000	$155,912	15.5%
System Renewal	$115,780	$143,563	24.0%	$20,000	$36,215	81.1%
System Service			--			--
General Plant	$5,700	$3,854	-32.4%	$5,700	$8,595	50.8%
TOTAL EXPENDITURE	$155,980	$227,282	45.7%	$160,700	$200,722	24.9%
Capital Contributions	-$5,775	-$60,245	943.2%	-$16,700	-$11,125	-33.4%
Net Capital Expenditures	$150,205	$167,037	11.2%	$144,000	$189,597	31.7%
System O&M	$89,684	$89,782	0.1%	$96,334	$82,775	-14.1%

CATEGORY	2020			2021			2022		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var
	$ '000		%	*$ '000*		%	*$ '000*		%
System Access	$53,000	$238,671	350.3%	$53,000	$57,728	8.9%	$78,000	$331,300	324.7%
System Renewal	$60,000	$77,545	29.2%	$62,000	$108,065	74.3%	$40,000	$112,225	180.6%
System Service		$11,532	--		$10,123	--		$6,000	--
General Plant	$5,700	$4,676	-18.0%	$5,700	$37,605	559.7%	$5,700	$5,700	0.0%
TOTAL EXPENDITURE	$118,700	$332,424	180.1%	$120,700	$213,521	76.9%	$123,700	$455,225	268.0%
Capital Contributions		-$240,151	--		-$20,000	--		-$80,000	--
Net Capital Expenditures	$118,700	$92,273	-22.3%	$120,700	$193,521	60.3%	$123,700	$375,225	203.3%
System O&M	$98,742	$111,374	12.8%	$101,201	$90,830	-10.2%	$103,741	$93,828	-9.6%

Table 3 - Planned Capital Investments by Year (Table ES-1)

CATEGORY	Test	Test+1	Test+2	Test+3	Test+4
	2023	**2024**	**2025**	**2026**	**2027**
	Forecast	Forecast	Forecast	Forecast	Forecast
	$	$	$	$	$
System Access	40,000	42,000	53,000	42,000	65,000
System Renewal	107,050	90,650	72,550	62,700	58,850
System Service	6,000	6,000	6,000	0	0
General Plant	5,700	5,700	5,700	5,700	5,700
Total	**158,750**	**144,350**	**137,250**	**110,400**	**129,550**
Contributed Capital	-10,000	-10,000	-10,000	-10,000	-10,000
Net Capital	**148,750**	**134,350**	**127,250**	**100,400**	**119,550**
System O&M	96,924	100,122	103,426	106,839	110,364

CHEI's capital investment has fluctuated over the last five years. The year-over-year fluctuation can be attributed to new development (System Access) and the replacement of transformers and poles (System Renewal).

CHEI did not record any expenses in Service System until 2020, when it started its PCB replacement program.

The General Plant category had remained relatively stable except for 2021, when a new AMI (Advanced Metering Infrastructure) was implemented, replacing a twelve-year-old system. Details can be found in section 4 of the report.

For the forecasted period, capital investments continue but at a more even pace. The focus going forward will be to continue with its replacements of aging transformers and the replacement of three poles per year. Overall, CHEI believes the proposed average annual investment is reasonable.

Having a relatively small distribution system makes it easier to manage, including finding a reasonable balance between capital and operational (O&M) expenses. CHEI’s spending in both categories are evenly paced and therefore is well balanced. O&M expenses and forecasts include costs such as “trouble calls,” tree trimming, for example, which are for the most part stable and easy to forecast based on a review of past issues. CHEI considers the overall condition of its system

CHEI has not included any expenditures for non-distribution activities in its capital budget.

2 DISTRIBUTION SYSTEM PLAN

Consistent with best practices, CHEI has replaced or upgraded equipment when economically viable or when the equipment is no longer functioning reliably. Hence it has a range of vintages of equipment that is planned to be replaced in a fiscally responsible manner. This has not presented any issues, and this will continue to be CHEI’s practice. In general, only end-of-life assets will be replaced. The net result has been that while the average age of the system has increased slightly, the system's reliability has steadily improved to meet the expectations of CHEI’s customers.

CHEI has followed the best practices of the electricity distribution industry for many years, including OEB’s Distribution System Code (DSC) which sets out good utility practices, minimum performance standards for electricity distribution systems in Ontario, and minimum inspection requirements for distribution equipment. Consistent with best practices, CHEI has diligently maintained its equipment in safe and reliable working order.

2.1 Distribution System Plan Overview

While CHEI’s focus is to replace aging equipment, other regulatory requirements that require additional major capital expenditures remain firmly in place (e.g., the “obligation to connect” new growth and maintaining the highest electrical safety standards by removing all PCB contaminants, for example).

Ongoing projects are phased over several years if the financial impact is significant and there is time available to do so. An example of this is the replacement of poles and transformers, which have been performed in segments over several years. However, CHEI also addresses projects that have urgency associated with them, such as the pole and transformers replacement equipment failure (customer outages) and /or oil leaking into the environment where possible.

CHEI’s primary focus is to safeguard its current reliability achievements while meeting its other obligations; the most important of such commitments is minimizing any increases in its customers’ bills.

2.2 Coordinated Planning with Third Parties

2.2.1 Local Planning Coordination

CHEI is part of a circulation list that receives regular updates from the municipality concerning zoning amendments and new projects in the service territory. When CHEI receives such notice, the utility can comment and meet with the developer to discuss the project and impact, if any.

As a fully embedded distributor, CHEI is also in constant contact with the account executive at Hydro One. The communication flows both ways in that both utilities keep each other informed of any occurring issue that could affect either utility. Both utilities communicate and meet as necessary to share information on project and construction planning.

2.2.2 Development Planning

CHEI is in constant contact with developers within its territory. Once CHEI is informed of any new developments within its service area, it becomes an active planning participant and will meet with developers to discuss and plan the project. There has been a significant recent development in the CHEI service area and the area that borders Hydro One's territory. Coordination of services beyond its service territory requires joint planning with Hydro One Networks.

Table 1 below shows the development areas within the town of Embrun.

Table 4 - Embrun Development Areas

Below is a legend for Figure 1 as to what neighborhoods each colour represents:

- Yellow - Industrial Park
- Red - Business Park
- Green - Chantal Development
- Light Blue - Centre Ville
- Purple - Bourdeau Development in the Embrun-Sud (Embrun South) area
- Pink - Lapointe Development and Mélanie Construction
- Orange – Maplevale

Since its last DSP in 2017, two new developments have been energized:

- Subdivision Faubourg Ste-Marie Phase II (2021) -54 lots (Purple Area)
- Subdivision Versailles Phase III (2021) -42 lots (Pink Area)

Table 1 below shows subdivision costs from 2018-to 2022.

Table 5 - Historical Subdivision Development Costs by Year

Year/ Development	2018	2019	2020	2021	2022
Faubourg Ste-Marie Phase II	$ 0	$ 0	$ 0	$99,219	$ 0
Versailles Phase III	$ 0	$ 0	$ 0	$89,877	$ 0
Faubourg Ste-Marie Phase III	$ 0	$ 0	$ 0	$ 0	$115,000
Central Park	$ 0	$ 0	$ 0	$ 0	$173,000
Total	$ 0	$ 0	$ 0	$189,096	$288,000

The costs listed above are necessary to supply the new subdivisions with the required equipment to deliver safe, reliable, efficient electricity to the new customers and ensure that existing customers are unaffected by the new service.

Two new subdivisions project are planned for 2022, requiring a Service Area Amendment.

Subdivision Faubourg Ste-Marie Phase III (Approximately 65 lots) is scheduled to start in July 2022.

A capital expenditure estimation of $115,000.00 is forecast for this project.

Subdivision Central Park (Approximately 250 lots) is also expected to start in July 2022. The new development cuts across Hydro One's territory and CHEI's territory. The developer has requested that CHEI be the service provider for the new subdivision. Discussions are still ongoing. CHEI and the developer expect a formal decision and arrangement by March 2022. The outcome of these discussions is expected to be formalized in the Spring of 2022.

While CHEI is a small utility, it is guided by and strives to comply with the OEB's four key target objectives referenced in the Renewed Regulatory Framework for Electricity Distributors (RRFE)

- Customer focus
- Operational effectiveness
- Public policy responsiveness

- Financial performance

CHEI has adopted good utility practices of the electricity distribution industry. This includes adhering to the OEB's DSC that sets out good utility practices, minimum performance standards for electricity distribution systems in Ontario, and minimum inspection requirements for distribution equipment. Consistent with good practices, CHEI has maintained its equipment in safe and reliable working order and, only when economically justified, upgraded, or replaced its equipment. CHEI has been prudent when incurring costs since customer satisfaction survey results indicate that the low price of electricity is an essential factor to customers.

2.2.3 Regional Planning

CHEI, Hydro One, Rideau St. Lawrence, and IESO are part of the St. Lawrence Region Study area. The most recent study, entitled Needs Assessment, and a Regional Infrastructure, was conducted in September of 2021. Its scope included:

- Review and reaffirm needs/plans identified in the previous report; and
- Identification and assessment of system capacity, reliability, operation, and aging infrastructure needs in the region; and
- Develop options for need(s) and/or preferred plan or recommend which conditions require further assessment/regional coordination.

CHEI's primary input into the report concerns the load forecast, which assists Hydro One with its regional planning. Nothing flagged in this report affected the work planned or capital investment in the near future.

2.3 Coordinated Planning with Third Parties

2.3.1 Compliance with Regulatory Requirements

CHEI has regulatory obligations and responsibilities to the Ontario Energy Board (OEB) and the Electrical Safety Authority (ESA). There are comprehensive OEB codes and guidelines, in addition to the Electricity Distribution Rate Handbook, that has compliance and reporting requirements for all LDCs

CHEI reports its Reliability Indices to the OEB and focuses on maintaining its high-performance levels in all aspects of its operations and planning activities. Its reliability performance track record is presented in the section of the plan.

The OEB uses various performance ranking methods from time to time and for different purposes, including annual performance ranking (PEG), annual reporting, safety audits, bi-annual surveys, etc.

The Ontario Energy Board is the primary regulatory organization overseeing CHEI's activities, with lesser regulatory roles being played by the Independent Electricity System Operator ("IESO"), the Electrical Safety Authority (ESA), Measurement Canada, Ministry of Energy, etc.

To ensure CHEI is fully aware of the rules issued by these regulatory bodies that govern its activities – and therefore be able to be fully compliant with these rules – multiple information sources are monitored daily. Both official (i.e., regulatory) and unofficial information requests from the overseeing bodies are responded to accurately and promptly.

CHEI's most active role with its regulator is through its annual application to the OEB for review of its tariff of rates and charges through either a cost of service ("COS") rate application or incentive regulation mechanism ("IRM") rate application which allows for inflation but is then reduced for both a common improvement factor and a stretch factor. CHEI's last COS application was made with a rate change applicable in 2018.

The COS applications, in particular, are seen as an opportunity to provide OEB staff and intervenors with all the required information in a fully transparent manner; they are also an opportunity to provide a different perspective on the hard facts that may not be obvious without significant analysis.

2.3.2 Compliance with Ont. Reg. 22/04

All licensed distributors in Ontario must comply with Ontario Regulation 22/04 Electrical Distribution Safety, and compliance with this regulation is subject to annual Audits and Declarations of Compliance. Section 4 of the regulation sets the safety standards and includes the statement:

"All distribution systems and the electrical installations and electrical equipment forming part of such systems shall be designed, constructed, installed, protected, used, maintained, repaired, extended, connected, and disconnected to reduce the probability of exposure to electrical safety hazards. O. Reg. 22/04, s. 4 (2)."

The regulation is designed to allow distributors to self-regulate, with requirements for annual Audits and annual Declarations of Compliance.

It is also required to submit an annual Declaration of Compliance for certain sections of the regulation; these have all indicated compliance.

2.4 Performance Measurement for Continuous Improvement

This section captures the results of CHEI's annual reliability performance, whose purpose is to maintain activities and assist in establishing priorities for capital investments while mindful of its ability to meet all the customer's needs in a sustainable manner.

This means that system reliability and cost of power are significant measures. Power quality has not been an issue, so while an essential overall consideration to the usability of the power, it only becomes a driver for spending on the system when power quality problems occur.

The cost of power is an essential matter for CHEI's customers. In their 2020 Customer Survey, the response to the question, "To what extent, if any, is the cost of Electrical service a strain on your household budget?" was that 70% of those surveyed responded with either "A great deal" or "Some." Hence, the cost is of importance to CHEI's customers. Most of the general comments were also with respect to the cost of electricity.

This indicates that CHEI's efforts in controlling its rates align with its customers' needs.

CHEI has a small service territory and, as such, does not have the workload to sustain a complement of staff to provide all the functions of the utility in-house. It acquires the services it needs on a contract basis. As a result, engineering studies are contracted out, as are the system construction, maintenance, emergency trouble-calls, and responses and billing. The overall management, purchasing, finance functions, and customer service are maintained in-house.

This approach works well for CHEI from a cost management and timing perspective for the physical work and the timely financial billing or project costing. Project work is contracted on a fixed price basis. Maintenance and repair work is based on unit prices negotiated in advance and authorized before the work is started except in the case of emergency work after hours.

This approach also means that CHEI does not incur fixed or ongoing costs for engineering work or power system work unless work is done. The work is defined, and the costs are contained. In this way, cost efficiency and work performance are kept high.

Overall, CHEI has worked to keep the bill impacts to its customers as low as possible. The bill impacts over the past four years have been as follows.

Table 6 - Bill Impacts

Year	2018	2019	2020	2021	2022
	CoS	**IRM**	**IRM**	**IRM**	**IRM**
Monthly Charge	$27.84	$32.11	$36.63	$37.44	$ 37.44
Volumetric	$0.0064	$0.0032			
Distribution Bill Impacts	20.74%	5.68%	6.96%	2.21%	0.00%
Total Bill Impact	7.25%	2.67%	1.24%	-4.42%	3.66%

CHEI notes that because the company is a Cooperative, the clients are also the owners/shareholders of the company. This means that if there are issues about the company's decisions, in addition to providing feedback individually as customers, they can be raised at the annual general meeting as company owners or shareholders. This is a unique aspect of this LDC compared to other LDC's and adds awareness and concern for customer/shareholder impacts.

2.4.1 System Reliability

Reliability Indices

Under Section 7.3.2 of the Ontario Energy Board's (OEB's) Electricity Distribution Rate Handbook, CHEI records and reports annually the following Service Reliability Indices:

$$\text{SAIDI} = \text{System Average Interruption Duration Index} = \frac{\text{Total Customer-Hours of Interruptions}}{\text{Total Customers Served}}$$

$$\text{SAIFI} = \text{System Average Interruption Frequency Index} = \frac{\text{Total Customer Interruptions}}{\text{Total Customers Served}}$$

$$\text{CAIDI} = \text{Customer Average Interruption Duration Index} = \frac{\text{Total Customer-Hours of Interruptions}}{\text{Total Customer Interruptions}}$$

These indices provide CHEI with an annual measure of its service performance for internal benchmarking and comparisons with other distribution companies as part of the OEB's Performance-Based Regulations.

CHEI section below discusses the cumulative number, hours, and customer hours of interruptions from 2016-to 2020.

Total number of Interruptions from 2016 to 2021

CHEI recorded a total of 111 interruptions over five years for an average of 22 per year. Of those 111 interruptions, 88 were related to Loss of Supply and Schedule Outages. The remaining 23 interruptions were attributed to all other causes for an average of 4.6 interruptions per year.

Total number of Customer Interruptions from 2016 to 2021

In summary, 20,409 customer interruption occurred on a five-year period for an average of 4,089 per year. Of the 20,409 customer interruptions, 20,375 were due to Loss of Supply and Schedule Outages. The remaining interruptions were attributed to other causes for an average of 6.8 Customer Interruptions per year.

Total number of Customer Hours from 2016 to 2021

CHEI recorded 120,497 customer hours of Interruption over five years for an average of 24,099 per year. Of those120 497 of customer hours, 119 982 were attributed to Loss of Supply and Schedule Outages. The remaining Customer Hours Interruption was attributed to other causes for an average of 103 Customer Hours Interruption per year.

The tables below show the outage performance of the system based on the standard SAIDI and SAIFI metrics. The tables represent System Reliability Indicators (SAIFI and SAIDI) from 2016-2020.

CHEI did not have any Major Events from 2016-to 2020.

The table below shows CHEI's reliability indicators over the past five years. As shown, its results exceed the OEB's expectations. CHEI confirms that its information below is consistent with the utility's RRR filing.

Table 7 – System Reliability (App 2-G)

Indicator	**OEB Minimum Standard**	**2016**	**2017**	**2018**	**2019**	**2020**
Low Voltage Connections	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%
High Voltage Connections	90.0%	n/a	n/a	n/a	n/a	n/a
Telephone Accessibility	65.0%	95.20%	92.42%	94.26%	96.38%	95.46%
Appointments Met	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Written Response to Enquires	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Emergency Urban Response	80.0%	100.0%	100.0%	100.0%	100.0%	83.33%
Emergency Rural Response	80.0%	n/a	n/a	n/a	n/a	n/a
Telephone Call Abandon Rate	10.0%	4.80%	6.58%	5.74%	3.60%	4.54%
Appointment Scheduling	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rescheduling a Missed Appointment	100.0%	n/a	n/a	n/a	n/a	n/a
Reconnection Performance Standard	85.0%	100.0%	100.0%	100.0%	100.0%	n/a

Table 8 - System Reliability Indicators 2016

System Reliability Indicators	
Total Outages	
SAIDI Avg. outage duration (hours)	**0.04**
SAIFI Avg. outage frequency (interruptions / customer)	**0.23**
Loss of Supply Adjusted	
SAIDI Avg. outage duration (hours)	**0.04**
SAIFI Avg. outage frequency (interruptions / customer)	**0.23**
Loss of Supply and Major Events Adjusted	
SAIDI Avg. outage duration (hours)	**0.04**
SAIFI Avg. outage frequency (interruptions / customer)	**0.23**

Table 9 - Interruption 2016

		2016	**2016**	**2016**
Cause Code	**Description**	**# Interruption / As a result of the cause interruption**	**# Of Customer Interruption**	**# Customers Hours**
0	Unknow/Other	0	0	0
1	Scheduled Outage	23	485	88
2	Loss of Supply	5	10622	53070
3	Tree Contact	0	0	0
4	Lightning	0	0	0
5	Defective Equipment	0	0	0
6	Adverse Weather	0	0	0
7	Adverse Environment	0	0	0
8	Human Element	0	0	0
9	Foreign Interference	0	0	0

In 2016 all 28 interruptions occurred due to loss of supply from Hydro One and scheduled outages. No other outages were recorded. CHEI notes that it has little to no control over Loss of Supply, and planned outages are necessary to replace aging equipment.

Table 10 - System Reliability Indicators 2017

System Reliability Indicators	
Total Outages	
SAIDI Avg. outage duration (hours)	**0.09**
SAIFI Avg. outage frequency (interruptions / customer)	**1.00**
Loss of Supply Adjusted	
SAIDI Avg. outage duration (hours)	**0.09**
SAIFI Avg. outage frequency (interruptions / customer)	**0.01**
Loss of Supply and Major Events Adjusted	
SAIDI Avg. outage duration (hours)	**0.09**
SAIFI Avg. outage frequency (interruptions / customer)	**0.01**

Table 11 - Interruption 2017

Cause Code	**Description**	**2017** **# Interruption / As a result of the cause interruption**	**2017** **# Of Customer Interruption**	**2017** **# Customers Hours**
0	Unknow/Other	0	0	0
1	Scheduled Outage	10	10	10
2	Loss of Supply	1	2175	2175
3	Tree Contact	0	0	0
4	Lightning	0	0	0
5	Defective Equipment	5	5	14
6	Adverse Weather	0	0	0
7	Adverse Environment	0	0	0
8	Human Element	0	0	0
9	Foreign Interference	0	0	0

In 2017 16 interruptions occurred due to loss of supply from Hydro One and scheduled outages. The five interruptions causing loss of power recorded under “Defective Equipment” were due to a blown fuse at a transformer.

Table 12 - System Reliability Indicators 2018

System Reliability Indicators	
Total Outages	
SAIDI Avg. outage duration (hours)	**28.44**
SAIFI Avg. outage frequency (interruptions / customer)	**3.04**
Loss of Supply Adjusted	
SAIDI Avg. outage duration (hours)	**0.60**
SAIFI Avg. outage frequency (interruptions / customer)	**0.06**
Loss of Supply and Major Events Adjusted	
SAIDI Avg. outage duration (hours)	**0.60**
SAIFI Avg. outage frequency (interruptions / customer)	**0.06**

Table 13 - Interruption 2018

		2018	**2018**	**2018**
Cause Code	**Description**	**# Interruption / As a result of the cause interruption**	**# Of Customer Interruption**	**# Customers Hours**
0	Unknow/Other	0	0	0
1	Scheduled Outage	14	113	896
2	Loss of Supply	4	6830	63651
3	Tree Contact	0	0	0
4	Lightning	0	0	0
5	Defective Equipment	7	13	473
6	Adverse Weather	2	2	2
7	Adverse Environment	0	0	0
8	Human Element	0	0	0
9	Foreign Interference	0	0	0

In 2018 27 interruptions occurred due to loss of supply from Hydro One and scheduled outages. The 13 interruptions of lost power recorded under “Defective Equipment” were due to a blown fuse at a transformer, and 2 interruptions were caused by adverse weather was due to a severe thunderstorm.

Table 14 - System Reliability Indicators 2019

System Reliability Indicators	
Total Outages	
SAIDI Avg. outage duration (hours)	**0.03**
SAIFI Avg. outage frequency (interruptions / customer)	**0.09**
Loss of Supply Adjusted	
SAIDI Avg. outage duration (hours)	**0.03**
SAIFI Avg. outage frequency (interruptions / customer)	**0.09**
Loss of Supply and Major Events Adjusted	
SAIDI Avg. outage duration (hours)	**0.03**
SAIFI Avg. outage frequency (interruptions / customer)	**0.09**

Table 15 - Interruption 2019

Cause Code	**Description**	**2019** **# Interruption / As a result of the cause interruption**	**2019** **# Of Customer Interruption**	**2019** **# Customers Hours**
0	Unknown/Other	1	1	2.75
1	Scheduled Outage	13	120	32
2	Loss of Supply	0	0	0
3	Tree Contact	0	0	0
4	Lightning	0	0	0
5	Defective Equipment	2	6	3
6	Adverse Weather	1	1	1.75
7	Adverse Environment	0	0	0
8	Human Element	0	0	0
9	Foreign Interference	1	1	3

In 2019 13 interruptions were related to scheduled outages, most of which had to do with replacing aging transformers and maintenance program of pad-mounted transformers. The 2 interruptions of lost power recorded under “Defective Equipment” were due to a blown fuse at a transformer, and interruptions were caused by adverse weather was due to a severe thunderstorm.

Table 16 - System Reliability Indicators 2020

System Reliability Indicators	
Total Outages	
SAIDI Avg. outage duration (hours)	**0.03**
SAIFI Avg. outage frequency (interruptions / customer)	**0.01**
Loss of Supply Adjusted	
SAIDI Avg. outage duration (hours)	**0.03**
SAIFI Avg. outage frequency (interruptions / customer)	**0.01**
Loss of Supply and Major Events Adjusted	
SAIDI Avg. outage duration (hours)	**0.03**
SAIFI Avg. outage frequency (interruptions / customer)	**0.01**

Table 17 - Interruption 2020

		2020	**2020**	**2020**
Cause Code	**Description**	**# Interruption / As a result of the cause interruption**	**# Of Customer Interruption**	**# Customers Hours**
0	Unknown/Other	2	2	7.5
1	Scheduled Outage	20	20	60
2	Loss of Supply	0	0	0
3	Tree Contact	0	0	0
4	Lightning	0	0	0
5	Defective Equipment	2	2	4.5
6	Adverse Weather	0	0	0
7	Adverse Environment	0	0	0
8	Human Element	0	0	0
9	Foreign Interference	1	1	2

In 2020 of the total 25 interruptions, the majority were Scheduled Outage was related to replacing aging transformers and maintenance program of pad-mounted transformers. Other minor interruptions were related to other causes such as foreign interference and defective equipment.

Typically, a reliability target is set by taking the past five years' average for SAIDI and SAIFI. These values are extremely low for Embrun, with the loss of supply interruptions and schedule outages removed.

This information indicates that CHEI does not need to embark on significant capital or maintenance programs to address system performance issues. Mandatory programs included in the future budgets mostly replace aging transformers and pole replacement.

The remaining work forecast is attributed to replacing end-of-life poles as identified by the pole testing, replacing porcelain fuse cutouts, replacing porcelain air gap arrestors at the transformers.

These projects will be phased to smooth rate impacts. The switch and lightning arrestor program is an example of CHEI using information based on identified problems in other utilities. It recognizes that the same issues may occur on its system and proactively plans to address them within the constraints of rate impacts. These discretionary investments are modest and are planned to be undertaken to maintain the excellent reliability and safety record of the utility.

2.4.2 Performance Ranking

The 2020 Yearbook of Electricity Distributors being the latest data available in Tab “Unitized” the data shows that Embrun Hydro’s PP&E per customer is $1,774 per customer its OM&A per customer is 308. This compares to $6,319.10 per customer yearly and $417 in OM&A costs per customer produced for Hydro One.

This comparison to Hydro One is used because that is the utility that surrounds the CHEI service territory. Despite the bill increases, the cost of supporting the CHEI operation is less than half the per-customer cost of the Hydro One per customer cost. In addition, compared to other Distribution Utilities, it has among the lowest per customer costs in the province.

3 PLANNING AND ASSET MANAGEMENT PROCESS

Setting Priorities

In managing its' distribution system assets, CHEI's objective is to optimize performance of the assets at a reasonable cost with due regard for system reliability, safety, and customer service expectations. CHEI planning strategy involves providing its customers with an economical, safe, reliable supply of electricity. CHEI's guiding principles regarding Capital Expenditure involves assessing the asset as its approaches its end of useful life and plan to replace it before it fails.

CHEI does not believe that an asset should be replaced solely based on age. Therefore, it relies on its 3rd party operation firm to assess the age and "stress" as a determining factor of an asset's life and a sound indicator for the required maintenance or replacement of the asset. On this basis, in the LDC's opinion assets under greater stress should be monitored more closely and maintained more than those under less stress. This ensures a wise use of limited capital and maintenance budgets.

CHEI has taken the approach that the items most at risk need to be replaced first. This means the poles that failed inspection and transformers with oil leaks and cracked insulators. Next is the completion of Load break elbow and insert replacement program. These devices are used whenever switching takes place on the underground system. CHEI then addresses devices on its system that although it has not experienced problem, yet it is well known in the industry that the devices have known problems and defects that affect reliability and crew safety. These programs are carried out on a modest pace demonstrating due diligence and financial stewardship. CHEI currently relies on a set of tools and inputs that makes up its process and help set its capital investment priorities.

Overall Approach to Risk Management

The OEB's Distribution System Code (DSC) identifies its minimum system maintenance and inspection requirements that reflect good utility practices. This section describes CHEI's regular maintenance programs and their contribution to risk mitigation.

In terms of risk management, the utility's main assets are poles, transformers, and meters all of which will cause power failures should they fail. As such, risk management and mitigation are fundamental features of all business activities.

Amongst its tools and inputs are:

1) A Supervisory Control and Data Acquisition (SCADA) system.
2) A review of the results of the pole testing, which occurs every 4-5 years.
3) A review of the results of any other study or testing (e.g., inspections, line loss study,
4) a review of new regulatory requirements and associated costs.
5) Continuous communication and consultation with developers, the region, and Hydro One.
6) Reliance on its experienced line contractor (Sproule)'s recommendations concerning aging assets and reliability concerns.

7) Yearly tracking of its previous DSP vs. actuals vs. budget.
8) Yearly review of various indicators such as ROE, Rate Base, Revenue Requirement, all of which CHEI calculates on an annual basis and in advance of its Board of Directors approving its budgets.
9) Input from its customers through its annual member's meeting. (CHEI notes that the report is posted on its website for all customers to view.)
10) Input from its Board of Directors.

All activities above serve to identify cost drivers within the CHEI's distribution system and contribute significantly to setting capital investment priorities. The particular initiatives listed above can be described as CHEI's Asset Management Strategy. CHEI also performs maintenance and inspection activities in part to meet the requirements of the Distribution System Code but also to ensure its equipment continues to operate economically. It promotes a safe environment for the general public and its workers.

The risk involved in not replacing poles, transformers or any assets that is used in the distribution of electricity to its customers can be catastrophic in terms of costs, safety and overall impact on the customers and in some cases the environment.

Process of Tracking and Assessing Asset Conditions

CHEI records poles and transformers. It does this by entering them into a spreadsheet. The spreadsheets document the particulars of the asset such as class, height, location, and pole number as well as condition information for poles and location number, location, manufacturer, voltage and KVA, date installed, and condition information. Condition information is as of the last inspection, performed every five years. The asset records are used for equipment inspections, and the condition is updated after the assessment is carried out. Deficiencies are noted, and repairs or replacements are carried out the following year unless the condition will have a high probability of causing an environmental incident or a power outage or be a danger to the public, in which case the work is done as soon as possible. Depending on the required capital, this work may also be deferred. At a minimum, it is smoothed and spread in phases to mitigate the impact where possible. This is also done within the constraint of maintaining efficiency by creating reasonable quantities of work to be done. Because the system is small, often, the cost of the work required is less than the materiality threshold.

CHEI has had good reliability performance because it has been proactive in addressing issues. Since the last DSP CHEI initiative (Program of Underground transformer bushings and inserts), all the work on the transformers has been done.

CHEI upgraded its Scada to have a summary report for each feeder to make sure the feeders are well balance. Furthermore, the Scada has an alarm to identify which feeders are affected. The contractor received the warning and logs into the Scada. If a red light appears on the diagram, it means a loss of supply. If not, a contractor will investigate the fault of the feeder failure. However, the outages that remain after the Loss of Supply data are removed, and the planned outages are removed. The remaining outages are inconsequential. From a project justification point of view, the past reliability performance is not a driver to undertake capital work.

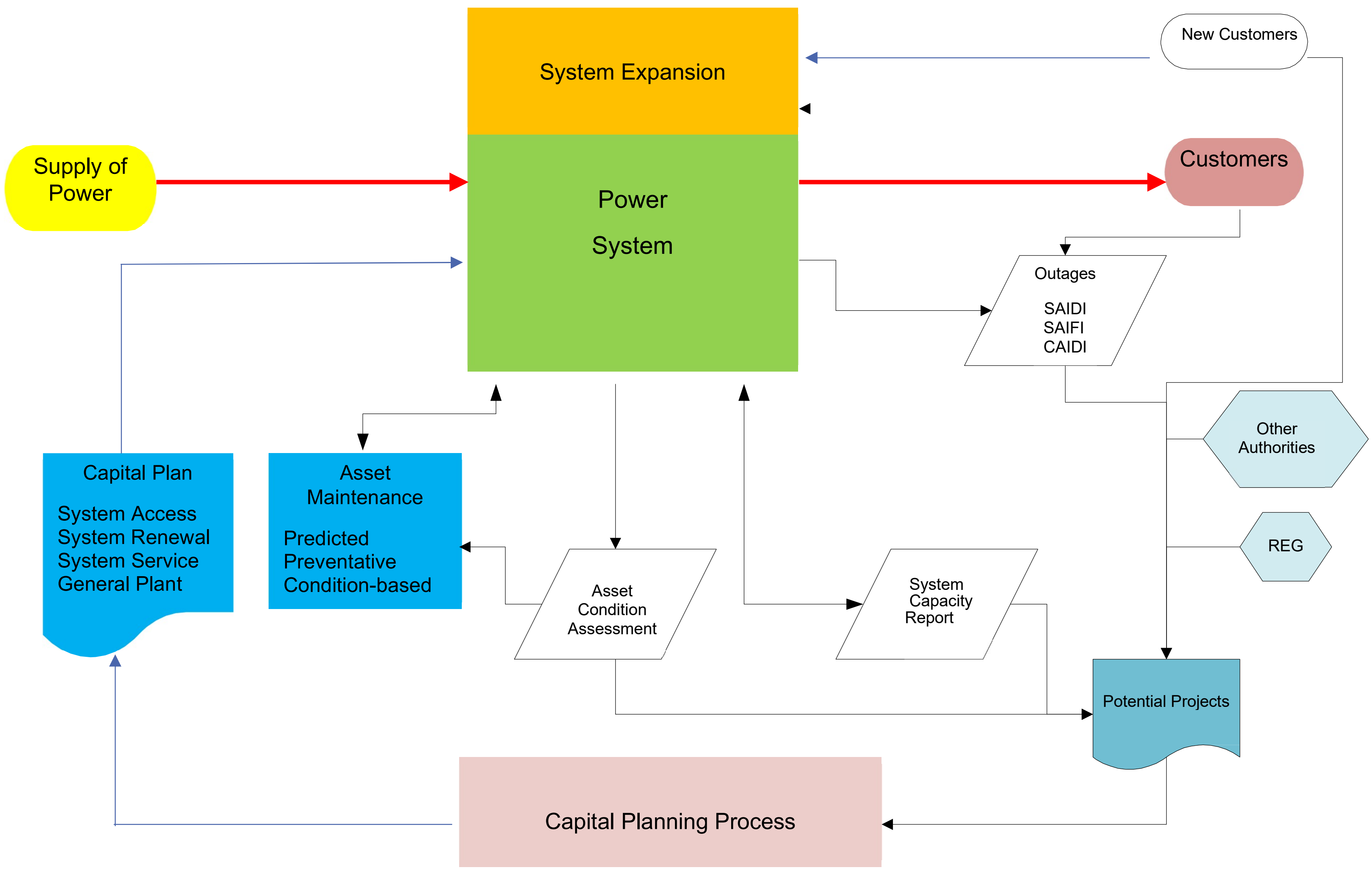
CHEI has a fused cutouts and porcelain air gap lightning arrestors replacement program.

The figure below shows the major high-level elements to developing the asset management plan. The items such as condition assessment, system capacity, and reliability are the main system inputs that result in potential projects to address existing problems. These are new customer projects (development), other authorities, and REG projects. These potential projects are reviewed and prioritized. In the review, different alternatives are considered, and project scope and details are selected.

Balancing Customer Needs and Planning Priorities

CHEI understands that its customers' priorities are to have consistent and reliable service at a reasonable cost. This is evident through the customers' responses to its bi-annual survey where 95% of customer ranked CHEI's service as excellent or good. The overwhelming consensus is that the customers' needs are being met and are in line with the utility's priorities.

As a small community and as a cooperative, members and customers are encouraged to share their thoughts either by communicating with the office staff or attending the annual meeting.


System Expansion
New Customers
Supply of Power
Power System
Customers
Outages
SAIDI
SAIFI
CAIDI
Other Authorities
REG
Capital Plan
System Access
System Renewal
System Service
General Plant
Asset Maintenance
Predicted
Preventative
Condition-based
Asset Condition Assessment
System Capacity Report
Potential Projects
Capital Planning Process

3.1 Overview of Assets Managed

CHEI notes that it has not changed the fundamentals of its asset management process since its last DSP in 2017.

CHEI has two municipal stations. One station(T1) is 7.5/10MVA 44kV-8.32kV and has four feeders emanating from the station. The transformer was built in 1988 and is 34 years old. It is supplied at 44kV from a Hydro One feeder. The second station (T2) is 10/13.3MVA 44Kv-8.32kV as four feeders from the substation. T2 was built in 2017 and is also supplied at 44kV.

The distribution system consists of about 18 km of overhead lines and about 19 km of underground lines. CHEI has 125 single-phase pole-mounted overhead transformers 51 three phases pole-mounted overhead transformers (17 services).

CHEI is very conscious of providing attention to its aging infrastructure. It has presented graphical representations of the ages of its primary system components and an overall representation of the average age of its main distribution assets. It then forecasts future capital investments to maintain a healthy average age.

Two new developments have been energized in the past 5 years, adding 96 units. From 2018 - 2020 approximately 140 units have been connected to the distribution system, and CHEI forecast for 2021-2022 another 120 units for a total of 260 units.

CHEI has taken this information into account together with the actual development taking place to plan and forecast its requirements.

The following tables summarize the age of its assets.

Table 18 - Single Phase Overhead Transformer Age Distribution

Age Distribution	Transformers Pole Mount
0 to 5	27
6 to10	18
11to15	14
16 to20	1
21 to 25	5
26 to 30	3
31 to 35	15
36 to 40	17
41 to 45	18
46 to 50	7
Total	**125**

CHEI has 18 overhead three-phase banks. The age distribution is shown in Figure 7 below.

Table 19 - Three Phase Overhead Transformer Age Distribution

Age Distribution	Transformers Bank Services (18)
0 to 5	2
6 to10	1
11to15	1
16to20	0
21 to 25	1
26 to 30	2
31 to 35	2
36 to 40	3
41 to 45	5
46 to 50	1
Total	**18**

CHEI has 147 underground pad-mounted transformers. The age distribution is shown in Figure 8 below. CHEI will start the pad mount transformers replacement in 2032 for an average of two pad mount replacements by year until 2042.

Table 20 - Underground Pad-mounted Transformer Age Distribution

Age Distribution	# Of Transformers
0 to 5	17
6 to10	40
11to15	3
16to20	51
21 to 25	15
26 to 30	5
31 to 35	16
Total	**147**

Poles by age – unavailable.

CHEI has 345 wood poles of various heights and classes that do not have identifiers as to the date installed at this time; therefore, the age cannot be provided. Determining the age of the existing poles would be challenging since many of the poles, particularly the older ones, have no readable date information. CHEI addresses this by having frequent inspections to ensure the integrity of the pole structures. In addition, CHEI has purchased pole testing equipment to perform more scientific testing.

The current and future pole testing method identifies poles at the end of life and needs replacement. These poles are included in the capital plan.

3.3 Risk Mitigation & Lifecycle Optimization

CHEI is a small utility that does not have policies on lifecycle optimization. Its practices are to meet the statutory requirements of the Distribution System Code. To this end, the three-year inspection of plant requirements is met. The inspection performed by the contractor notes any deficiencies, and these are addressed by the contractor either at the time of inspection if it is a "quick job" or it is noted. A quote is provided if it is a more significant job. Some aspects like overhead line patrols are carried out by CHEI staff and are performed more frequently than once every three years as required by the DSC because the patrols also identify the required tree trimming. Tree trimming is done on an annual basis with a cycle rotation.

All system switching, power restoration, after-hours trouble calls and responses, pole testing and replacement, line construction, and utility locates are performed by the contractor.

From a risk mitigation perspective, CHEI aims to meet or exceed the system maintenance and inspection requirements of the Ontario Energy Board's Distribution System Code (DSC) to minimize subsequent repair and/or replacement costs. Section 4.4.1 of the DSC states:

"A distributor shall maintain its distribution system per good utility practice and performance standards to ensure reliability and quality of electricity service, on both a short-term and long-term basis."

The following routine maintenance programs are consistent with good utility practices and are applied routinely within the CHEI distribution system.

Wood pole testing and replacement

Pole testing is carried out on a five-year cycle. CHEI uses a sonic pole tester. This equipment is expected to provide better insight into the condition of the tested pole than was previously available. Based on the results obtained in 2021, nine poles must be replaced on a three-year term (three poles per year starting in 2021). The next testing cycle will be in 2026. Based on the pole test results, the defective poles are replaced before the next testing cycle while considering the other capital work required and the resulting rate impacts. Note, however, that this discussion is in the context of forecast System Renewal expenditures between 2023 and 2027 below the materiality threshold, which means that the pole replacement is not a large project. Poles are tested to determine the "end of life," and no other process is applicable.

Poles are tested to see if they are adequate as support structures for wires, switches, and transformers. If they are not as determined by testing, they are replaced immediately if deemed in danger of failing imminently or on a scheduled basis within a budgetary context.

PCB Testing and Replacement of Distribution Transformers

Transformers are checked visually for evidence of abnormal heating at the primary and secondary connections. Typically, this connection problem is corrected without removing the transformer. Transformers can have damaged bushings or oil leaks. These conditions would cause the utility to replace the transformer. Some transformers have evidence of corrosion. If this is just surface rust, the surface is cleaned, repainted, and left in service. Where the rust is severe and has weakened the tank wall, the transformer is replaced.

As a result of environmental legislation, only those units manufactured before 1985 are candidates for PCB contamination. CHEI has not completed its testing to date. All contaminated units will be replaced in accordance with the legislation by 2024.

Fused Cutouts and Porcelain Air Gap Lightning Arrestors Replacement Program

CHEI also uses the experience of its line contractor, including considering the experience of other utilities. An example is replacing the porcelain fused cutouts with polymer fused cutouts and replacing porcelain air gap type lightning arrestors with polymer, solid dielectric arrestors. These projects are being planned proactively because of the problems with this equipment in various utilities, even if it has not caused outages or health risks at CHEI. CHEI believes that if they do nothing, these devices will cause problems in the future. By being proactive, CHEI's excellent reliability, health, and safety records can be maintained.

Municipal Stations

The MS transformers are maintained cyclically, and standard oil testing is done annually. Similarly, station feeder switches and protection are maintained.

Tree Trimming

CHEI's tree trimming is completed in accordance with its established three-year cycle; this is usual utility practice.

Appendix C - Minimum Inspection Requirements of the DSC describes the inspection cycles and defines patrol inspections for each major distribution facility.

As shown in section 2.4, CHEI has not reported any outages related to Tree Contact in five years. This indicates that CHEI has an excellent rotation program for tree trimming CHEI has a very reliable system.

Although CHEI does not have a Risk Register *per se*, it conceptually knows which factors can affect its safety, reliability, and customers' needs. Amongst the risks it constantly monitors are;

- Mandates from OEB, IESO, and ESA
- Legislative changes by the Ministry of Energy, including forced amalgamations
- Growth and developments and their impact on CHEI's distribution system.
- Cyber security
- More recently, unexpected increase in the cost of equipment, resources, and material as well as delays in receiving equipment due to the pandemic.

4 CAPITAL EXPENDITURE PLAN

4.1 Capital Investment Priorities in the Distribution System

CHEI's financial stability strategy is described based on the following principles. CHEI has a process for developing its capital budget and a prioritization system based on the priorities of a wide range of stakeholders, corporate strategies, and regulatory requirements. The following high-level inputs, along with the list at Section 3, which describes the set of tools and inputs CHEI currently relies on to help set its capital investment priorities, contribute to a final capital investment budget depending on the individual evaluations and timing initiatives.

- New load growth and development projects
- Municipally driven projects
- Regulatory initiatives
- System Reliability
- Infrastructure renewal projects
- Elimination of environmental/health or safety risks
- Information technology and corporate administration

Need, Scope, Evaluation Criteria, Business Cases

All of CHEI's capital investments are non-discretionary and are critical to ensuring continuity of existing service, implementing new service and ensuring the safe and reliable electricity to its customers. As such the "need", the "scope" and the "evaluation criteria" and "business cases" are not documented as these projects are considered "a must". This applies to projects that are small in nature as well as to project that exceed the materiality threshold.

With respect to innovation and as explained in Exhibit 1, while CHEI aspires and encourages the development of new creative services and processes which will allow customers to manage their consumption and bills better, the evidence for small utilities is mixed as to their ability to do so successfully. CHEI believes there needs to be a more cost-effective approach to the facilitation of innovation before including such spending in its plans and rates. That said, CHEI will continue to seek open-type innovation, i.e., collaborating with other similar sized and like-minded utilities toward innovation goals, which could offer a more appropriate potential for supporting innovation while also helping to tame the costs.

4.2 Capital Expenditure Planning Process Overview

CHEI notes that it has not changed the fundamentals of the budgetary planning process since its last DSP in 2017. In managing its' distribution system assets, CHEI's objective is to optimize the performance of the assets at a reasonable cost with due regard for system reliability, safety, and customer service expectations. CHEI is committed to providing our customers with an economical, safe, reliable electricity supply and enabling our community to be energy efficient. These objectives have been met by applying thorough and sound planning, prudent and justified budgeting while implementing the documented capital and operating plans.

4.3 System Capability Assessment for Renewable Energy Generation

CHEI currently has REG connected to its system. These are exclusively solar installations and fall under the label of micro-fit installations. Table 4 below indicates the number of connections and the capacity installed by year since 2010. There are no outstanding at the time of the filing.

CHEI is not expecting any larger REG project which would require the investigation of constraints or that would affect the upstream supply.

Table 21 - Connected REG Loads

Connected REG Loads

Year	# Of connections	Type	Solar array rating in kw	Feeder	Voltage	Constraints	Impact
2010	1	Solar Photovoltaic (Roof Top)	5	F 3	Secondary 120/240 Primary 4800	No	No
2011	2	Solar Photovoltaic (Roof Top)	18	F 1 (both)	Secondary 120/240 Primary 4800	No	No
2012	2	Solar Photovoltaic (Roof Top)	20	1 on F 3 1 on F 1	Secondary 120/240 Primary 4800	No	No
2013	3	Solar Photovoltaic (Roof Top)	30	2 on F 3 1 on F 2	Secondary 120/240 Primary 4800	No	No
2014	2	Solar Photovoltaic (Roof Top)	20	F 3(both)	Secondary 120/240 Primary 4800	No	No
2015	1	Solar Photovoltaic (Roof Top	4.5	F 3	Secondary 120/240 Primary 4800	No	No
2016	1	Solar Photovoltaic (Roof Top)	10	F 3	Secondary 120/240 Primary 4800	No	No
2017	1	Solar Photovoltaic (Roof Top)	10	F2	Secondary 120/240 Primary 4800	No	No
Total	13		117.5				

4.4 Rate-Funded Activities to Defer Distribution Infrastructure

CHEI does not have any pending or outstanding application for CDM funding to defer infrastructure.

4.5 Summary of Historical Capital Expenditures (2018-2021)

Table ES-1 below provides the Historical Investments CHEI has made between 2018 and projected for 2022. Capital projects are detailed in section 4 of this report.

Table 22 - Historical Capital Investments by Year (Table ES-1)

	Historical (previous actual)			
	Test-5	Test-4	Test-3	Test-2
	2018	**2019**	**2020**	**2021**
CATEGORY	Actual	Actual	Actual	Actual
	$	$	$	$
System Access	79,865	155,912	238,671	57,728
System Renewal	143,563	36,215	77,545	108,065
System Service	0	0	11,532	10,123
General Plant	3,854	8,495	4,676	37,605
Total	227,282	200,622	332,424	213,521
Contributed Capital	-60,245	-11,125	-240,151	-20,000
Net Capital	167,037	189,497	92,273	193,521
System O&M	89,782	82,775	111,374	90,830

4.6 2018-2021 Capital Investments and Justification of Material Expenses

Table 23 – 2018 Capital Expenses vs. DSP

System Access		DSP Plan – 2018	Actual Year End 2018
Amounts are in dollars			
Land substation (1805)		$0	$6,900
Survey substation(1820)			$935
	Subtotal		*$7,835*
New O/H and U/G services 1855		$20,000	$20,819
Meters 1860		$8,000	$17,552
	Subtotal	*$28,000*	*$38,370*
Centre Urgel Forget Addition(1850)		$0	$11,685
Centre Urgel Forget Addition(1845)		$0	$17,800
	Subtotal	*$0*	*$29,485*
Replace pole with new 45` -1830		$6,500	$4,175
	Subtotal	$6,500	$4,175
Category Total		**$34,500**	**$79,865**
System Renewal		**DSP Plan – 2018**	**Actual Year End 2018**
Pole Replacement # 11 - 1830		$6,800	$7,300
Pole Replacement # 48 - 1830		$4,500	$4,800
Pole Replacement # 81 - 1830		$6,500	$6,800
Pole Replacement # 108 -1830		$6,200	$6,400
Pole Replacement # 139 - 1830		$6,500	$6,500
Pole Replacement # 353 -1830		$2,500	$3,000
Pole Replacement # 415 -1830		$4,500	$4,800
Pole Replacement # 465 -1830		$4,000	$4,200
	Subtotal	*$41,500*	*$43,800*
Transformer Replacement # 431 (1850)		$4,875	$3,195
Transfo $			
Transformer Replacement # 456 (1850)		$5,575	$3,907
Transfo $			$783
Transformer Replacement # 474 (1850)		$5,135	$3,195
Transfo $			$783
Transformer Replacement # 501 (1850)		$5,775	
Transfo 3075.00$			$3,075
Labour 3600.00$			$3,600
Transformer Replacement # 504 (1850)		$2,725	$1,500

Transfo $		$4,195
Transformer Replacement # 506 (1850)	$4,835	$3,195
Transfo $		$4,195
Transformer Replacement # 520 (1850)	$5,035	
Transfo $		$4,195
		$2,018
Transformer Replacement # 522 (1850)	$3,825	$3,195
Transfo $		$2,382
Transformer Replacement # 525 (1850)	$5,675	$3,195
Transfo $		$3,195
Transformer Replacement # 550 (1850)	$2,725	$3,195
Transfo $		$4,195
Transformer Replacement # 35 (1850)	$8,100	$6,082
Transfo 3195.00$		$3,195
Subtotal	*$54,280*	*$66,469*
Transformers Program (Elbow and Inserts) -1850	$20,000	$13,114
Subtotal	*$20,000*	*$13,114*
Replace Cutout Arrestor		
1122 Notre-Dame - 1835		$1,826
Replace Solid Blade Switch F1 and		
F2 Dip pole St-Jacques - 1835		$4,842
Stantec Map Upgrade - 1835		$3,557
4 La Croisé - Replace cutout-arresters		$2,957
and hardware - 1835		
Install 1 span of 266 meters spun buss		$2,000
1155 Notre- Dame -1835		
Installation Spun Buss - Remove		$5,000
all open buss wire- Forget & Jeanne D`arc		
Street -1835		
Subtotal		*$20,181*
Category Total	**$115,780**	**$143,563**

System Service	DSP Plan – 2018	Actual Year End 2018
No Project		
Category Total		

General Plant		**DSP Plan – 2018**	**Actual Year End 2018**
Software - 1611		$3,000	$1,081
Office Equipment 1915		$1,200	$2,773
Computer & Hardware -1920		$1,500	
	Subtotal	*$5,700*	*$3,853*
Category Total		**$5,700**	**$3,853**
Total Capital		**$155,980**	**$227,282**
Contributed Capital		**-$5,775**	**-$60,245**
Net Capital		**$150,205**	**$167,037**

2018 System Access

New Services:

Actuals exceeded the DSP planned by $819.00.

Meter:

Actuals were in exceeded the DSP planned by $9,552.00. The reason is that CHEI purchased additional meters for the meter reverification program.

New service pole:

Actuals are lower than the DSP planned by $2,325.00. A new connection was the reason for the increase.

Unforeseen expenses not accounted for in the DSP

$7 835.00 in unexpected costs were incurred to finalize the construction of the substation by replacing two entrance culverts and the related surveyor costs incurred.

$29,485.00 of unforeseen expenses were incurred due to connecting a new building (26 units) to the distribution system.

2018 System Renewal

Poles replacement:

Actuals exceeded the DSP planned by $2,300.00. Eight poles needed replacing as they were identified as a risk to the system reliability due to the decaying of the wood fiber.

Transformer's replacement:

As part of the inspections, 11 transformers were identified that had cracked bushings and were leaking oil. These transformers were replaced to prevent future power interruptions and prevent transformer oil from affecting the environment.

Actuals exceeded the DSP planned by $12,189.00.

Transformers Program (Elbow and Inserts):

This program relates to the Mini Pad Transformer, Elbow, and Insert replacement program. Load break elbows and inserts have a limited life expectancy. After repeated normal operations, the ablative material on the elbow is worn away, and it no longer has rated interrupting capability. In addition, if the elbow is not lubricated and operated, the elbow becomes extremely difficult to handle. Both these conditions present a safety hazard to the operator. This is being addressed by replacing the elbow and the transformer insert.

Actuals were in exceeded the DSP planned by $6,887.

Actual not plan in DSP forecast in 2018

$20,181.00 of unforeseen expenses relating to equipment replacement due to end of life and safety.

Also, a map upgrade was done by Stantec to identify the open point on the map for safety when the crew needed to do some work on the distribution system.

2018 System Service:

Not Applicable

2018 General Plant:

Actuals were lower than the DSP planned by $1,847.00 than the DSP forecast in 2018.

2018 Contributed Capital:

Actuals were lower than the DSP planned by $54,470.00. Actuals were higher than the DSP panned by $54,470.00 due to New Service Connection and the new addition building of Centre Urgel Forget

A

Table 24 – 2019 Capital Expenses vs. DSP

System Access		**DSP Plan – 2019**	Year-End 2019
Amounts are in dollars			
New O/H and U/G services 1855		$20,000	$23,364
Meters 1860		$8,000	
Meters 1860 (Meter replacement)		$17,000	$16,372
	Subtotal	*$45,000*	*$39,736*
Scada			
Scada Improvement			$33,653
	Subtotal		*$33,653*
Engineer Fees Patenaude East Subdivision			$2,360
	Subtotal		*$2,360*
Relocate Line on St-Jacques Road		$90,000	$20,000
New pole Project St-Jacques Road			$2,500
	Subtotal	*$90,000*	*$22,500*
Transformer Inventory			
225 kva 120/208 volt 3 phase			$14,219
Pole mount Transformer Single Phase			
25-50-75-100 KVA			$21,460
	Subtotal		*$35,679*
Blais Street Enhancement			$16,240
	Subtotal		*$16,240*
Maintenance Manual New Substation (2017)			$5,743
	Subtotal		*$5,743*
Category Total		**$135,000**	**$155,912**
System Renewal		**DSP Plan – 2019**	**Year End 2019**
Transformers Program (Elbow and Inserts) -1850		$20,000	$10,139
	Subtotal	*$20,000*	*$10,139*
Transformers Replacement			
Transformer Replacement # 403 -1850			$2,000
Transformer -1850 - 100 KVA			$5,211
Transformer Replacement # 412-1850			$2,000
Transformer -1850 - 50 KVA			$2,350
Transformer Replacement # 422 -1850			$2,000
Transformer -1850 -25 KVA -IN STOCK			$ -

Transformer Replacement # 434-1850		$2,000
Transformer -1850 -50 KVA		$2,350
Transformer Replacement # 440-1850		$2,000
Transformer -1850 -50 KVA		$2,350
Subtotal		*$22,261*
Overhead Conductors		
3 Cut-Off Switch Nore- Dame Street		$2,535
Subtotal		*$2,535*
Substation Lightning		$1,280
Subtotal		*$1,280*
Category Total	**$20,000**	**$36,215**
System Service	**DSP Plan – 2019**	**Year-End 2019**
No Projects		
General Plant	**DSP Plan – 2019**	**Year-End 2019**
Software - 1611	$3,000	$2,988
Office Equipment 1915	$1,200	$909
Computer & Hardware -1920	$1,500	$4,598
Category Total	**$5,700**	**$8,495**
Total Capital	**$160,700**	**$200,621**
Contributed Capital	**-$16,700**	**-$11,125**
Net Capital	**$144,000**	**$189,496**

2019 System Access

New Services:

Actuals exceeded the DSP planned by $3,364. The increase is related to new service requests.

Meter:

Actuals were lower than the DSP planned by $8,628. This is due to the utility having purchased meters in 2018. Other reasons are related to new services and the replacement of meter seal extension and defective meters.

Relocate Line on St-Jacques and new pole:

This project is on St-Jacques Blvd north of Sainte-Therese Blvd. The homes on the west side of St-Jacques Blvd were being supplied from a line located in the rear lots of the customers. The utility did not have access to the easement. There was a vacant lot at the Sainte-Therese Blvd, which was planned to be developed. The owner requested that the line be removed. Various options were discussed. However, ultimately, the utility had no choice but to relocate the line as requested.

CHEI forecasted $90,000 to relocate the line in 2019. The project was completed for $22,500.00. Phase II and III were canceled because the developer canceled the project (New building).

Unforeseen expenses not accounted for in the DSP

Scada:

After consulting with the engineer (Stantec), the board director opted to improve the Scada system. The new improvement allowed the utility to obtain reports on each feeder (Amperage Reading) and send an alarm to the crew if a feeder failure occurs. The cost of this improvement was $33,653.00

Engineer fees (Stantec):

$5,743.00 was incurred to prepare a Maintenance Manual for the new substation. An additional $2,360.00 was incurred to review Faubourg Ste-Marie Phase II.

Transformer Inventory:

An expense of $35,679.00 to have necessary transformers in inventory to respond rapidly in the event of a failure of a transformer.

Enhancement Blais Street:

An expense of $16,240.00 occurred due to a bridge replacement on Blais Street by the municipality.

2019 System Renewal

Transformers Program (Elbow and Inserts):

This program relates to the Mini Pad Transformer, Elbow, and Insert replacement program. Load break elbows and inserts have a limited life expectancy. After repeated normal operations, the ablative material on the elbow is worn away, and it no longer has rated interrupting capability. In addition, if the elbow is not lubricated and operated, the elbow becomes extremely difficult to handle. Both these conditions present a safety hazard to the operator. This is being addressed by replacing the elbow and the transformer insert.

CHEI's actual expense was $9,861.00 lower than the DSP forecast in 2019.

Unforeseen expenses not accounted for in the DSP

Transformer replacements:

An expenditure of $ 22,261.00 was incurred to replace five transformers.

Three Cut-off Switch:

An expense of $ 2,535.00 occurred, which was not forecast in 2019 consisting of equipment replacement due to end of life and safety.

2019 System Service:

Not Applicable

2019 General Plant:

Actuals exceeded the DSP planned by $2,795. That amount difference consists of the purchase of one laptop and software.

Table 25 – 2020 Capital Expenses vs. DSP

System Access		**Plan**	**Actual Year End 2020**
Amounts are in dollars			
New O/H and U/G services 1855		$20,000	$31,633
Meters 1860		$5,000	$8,943
Meters 1860 (Smart Meter replace)		$10,000	
	Subtotal	$35,000	$40,576
New Transformers (inventory)		$18,000	$9,000
	Subtotal	$18,000	$9,000
Versailles III Project (1850)			$23,735
Versailles III Project (1845)			$66,142
Contributed Capital			
	Subtotal		$89,877
Patenaude Subdivision Phase II (1850)			$33,425
Patenaude Subdivision Phase II (1845)			$65,794
Contributed Capital			
	Subtotal		$99,219
Category Total		**$53,000**	**$238,671**
System Renewal		**Plan**	**Actual Year End 2020**
Replace of Porcelain Post Insulators St.-Jacques Rd (Double Circuit)		$20,000	
Subtotal		$20,000	
Replacement of Switch, Arrester And Mounting Bracket at individual pole mount transformer locations		$40,000	
	Subtotal	$40,000	
Poles replacement			
Pole replacement # 18			$4,453
Pole replacement # 461			$5,173
Pole replacement # 185			$6,800
	Subtotal		$16,425
Transformers Program			$21,041
(Elbow and Inserts) -1850			
	Subtotal		$21,041
Transformers Replacement			
Transformer Replacement # 57 PAD -1850			$7,083
Transformer Replacement # 58 PAD -1850			$7,083
Transformer Replacement # 59 PAD -1850			$7,083
Transformer Replacement # 414 -1850			$1,565
Transformer Replacement # 427 -1850			$3,624
Transformer Replacement # 446 -1850			$1,585
Transformer Replacement # 453 -1850			$1,975

Transformer Replacement # 478 -1850		$2,084
Transformer Replacement # 480 -1850		$1,582
Transformer Replacement # 510 -1850		$1,930
Transformer Replacement #513 -1850		$1,335
Transformer Replacement # 524 -1850		$1,720
Transformer Replacement #544 -1850		$1,432
Subtotal		$40,079
Category Total	**$60,000**	**$77,545**
System Service	**Plan**	**Actual Year End 2020**
PCB Transformers Dated Before 1985		
Transformer # 507		$4,290
Transformer # 524		$3,318
Transformer # 513		$3,924
Subtotal		$11,532
Category Total		**$11,532**
General Plant	**Plan**	**Actual Year End 2020**
Software - 1611	$3,000	$628
Office Equipment 1915	$1,200	$3,431
Computer & Hardware -1920	$1,500	$617
Subtotal	$5,700	$4,676
Category Total	**$5,700**	**$4,676**
Total Capital	**$118,700**	**$332,425**
Contributed Capital	**$0**	**-$240,151**
Net Capital	**$118,700**	**$92,274**

2020 System Access

New Services:

Actuals exceeded the DSP planned by $11,634. The increase is related to new service requests.

Meter:

Actuals were lower than the DSP planned by $6,057. This is due to the utility having purchased meters in 2018. Other reasons are related to new services and the replacement of meter seal extension and defective meters.

Transformer Inventory:

Actual expenses were lower by $9,000.00 compared to the DSP forecast in 2020. CHEI purchased transformers the previous year and had several in stock.

Unforeseen expenses not accounted for in the DSP

Versailles III Subdivision (42 lots):

This project provides the distribution system plant, primary and secondary cable, and transformers to develop 42 units.

The project's total cost was $89,877.00, including transformers, cable, and labor.

Faubourg Ste-Marie Phase II Subdivision (54 lots)

This project provides the distribution system plant, primary and secondary cable, and transformers for the development of 54 units

The project's total cost was $99,218.00, including transformers, cable, and labor.

2020 System Renewal:

Replace of Porcelain Post Insulators St-Jacques Rd (Double Circuit):

This project ended up not being needed and was canceled.

Replacement of Switch, Arrester, and Mounting Bracket at Individual pole-mount transformer location:

Porcelain-fused cutouts and porcelain air gap type arrestors fail. Both devices create safety hazards when they fall in service. Typically, the fused cut-out will fail by breaking while being operated by a line crew and either causes a short circuit or leave the crew doing the switching hanging on to a live wire with no place to park the lead safely. Air gap lightning arrestors may fail explosively either in service and create a hazard for anyone in the immediate vicinity, either the general public or a worker.

Due to Covid, that project estimated at $40,000 has been transferred to the 2021 calendar.

Unforeseen expenses not accounted for in the DSP

Poles replacement:

This expense is related to 3 poles being replaced at the cost of $16,426.00

Transformer replacements:

This expense is related to the 13 transformers being replaced at $40,079.00.

Transformers Program (Elbow and Inserts):

This program relates to the Mini Pad Transformer, Elbow, and Insert replacement program. Load break elbows and inserts have a limited life expectancy. After repeated normal operations, the ablative material on the elbow is worn away, and it no longer has rated interrupting capability. In addition, if the elbow is not lubricated and operated, the elbow becomes extremely difficult to handle. Both these conditions present a safety hazard to the operator. This is being addressed by replacing the elbow and the transformer insert.

CHEI's actual expense was $21,040.00. CHEI has completed the program.

2020 System Service:

CHEI, at the time of the DSP 2017 budget, forecast $25,000.00 for PCB Transformers Dated Before 1985 under System Access ($20,000.00) CHEI relocated that item to System Service.

An amount of $11,532.00 was incurred to dispose of three contaminated transformers.

2020 General Plant:

Actuals were lower by $1,023.00 when compared to the DSP forecast.

2020 Contribute Capital:

CHEI's actual contribution for 2020 ($240,150.00) was not budgeted in the DSP forecast in 2020.

Table 26 – 2021 Capital Expenses vs. DSP

Description		**Project Subtotal**	**Preliminary 2021**
Amounts are in dollars			
System Access		**Plan**	**Actual 2021**
New O/H and U/G services 1855		$20000	$38,580.06
Meters 1860		$15000	$12,092.51
	Subtotal	$35000	$50,672.57
New Transformers (Inventory))		$18000	$8,465
(Inventory) (25KVA and 167KVA)			
	Subtotal	$18000	$8,465
Pole Testing			
Asset Management 1830			$5,227.52
	Subtotal		$5,227.52
Distribution Map - Revision			
(Stantec - Sproule)			
1845 - Underground			$2,565
1835 - Overhead			$5,615
	Subtotal		$8,180
Category Total		$53000	$72,545.09
System Renewal		**Plan**	**Actual 2021**
Transformers Replacement			
Transformer Replacement # 405 -1850			$3,655
Transformer Replacement # 487 -1850			$4,400
Transformer Replacement # 488 -1850			$4,500
Transformer Replacement # 489 -1850			$4,400
Transformer Replacement # 490 -1850			$4,400
Transformer Replacement # 496 -1850			$4,400
Transformer Replacement # 508 -1850			$3,730
Transformer Replacement # 511 -1850			$3,525
Transformer Replacement # 517 -1850			$4,350
Transformer Replacement # 521 -1850			$5,925
Transformer Replacement # 530 -1850			$4,500
Transformer Replacement # 538 -1850			$4,450
	Subtotal		$52,235
Pole Replacement			
Pole # 477 - Wood pecker - 1830			$4,800
Pole # 159 TEST FAIL			$5,800
Pole # 346 TEST FAIL			$7,100
Pole # 215 TEST FAIL			$8,600
	Subtotal		$26,300
Bollard Transformer Notre-Dame			$4,000
As per ESA DDI			

	Plan	Actual 2021
Subtotal		$4,000
Replacement of Switch, Arrester, And Mounting bracket at individual pole mount transformer locations	$62,000	$27,609.59
Subtotal	$62,000	$27,609.59
Category Total	$62,000	$110,144.59
System Service	**Plan**	**Actual 2021**
PCB Transformers Dated Before 1985		$4,895
		$4,895
Category Total		$4,895
General Plant	**Plan**	**Actual 2021**
Software - 1611	$3,000	$512.73
Web site		$6500
Honeywell AMI Connexo NetSense		$28,492
Office Equipment 1915	$1,200	$75
Computer & Hardware -1920	$1,500	
Subtotal	$5,700	$35,579.73
Category Total	$5,700	$35,579.73
Total Capital	**$12,0700**	**$223164.41**
Contributed Capital	**$-**	**$3,148.05**
Net Capital	**$120,700**	**$220,016**

2021 System Access

New Services:

Actuals exceeded the DSP planned by $18,580. The increase is related to new service requests.

Meter:

Cost of customer requested new services related to new development and other customer requests, the replacement of meter seal extension and defective meters.

CHEI's actual expenses are lower by $2,907.00 than the DSP forecast in 2021.

Transformer Inventory:

Actual expenses were lower by $9,535.00 than the DSP forecast in 2020. CHEI purchased transformers the previous year and had several in stock.

Unforeseen expenses not accounted for in the DSP

Pole Testing:

As per DSP 2017, pole testing must be done every five years. Three poles have been replaced, and one was damaged by a woodpecker.

Distribution Map Revision:

The distribution map has been updated with new information to facilitate the work of the crew when a power failure occurs.

2021 System Renewal:

Replacement of Switch, Arrester, and Mounting Bracket at Individual pole-mount transformer location:

Porcelain fused cutouts and porcelain air gap type arrestors fail in service. Both devices create safety hazards when they fail. Typically, the fused cut-out will fail by breaking while being operated by a line crew and either causes a short circuit or leave the crew doing the switching hanging on to a live wire with no place to park the lead safely. Air gap lightning arrestors may fail explosively either in service and create a hazard for anyone in the immediate vicinity, either the general public or a worker.

CHEI had initially budgeted $40,000 in 2020. The project was moved to 2021 due to Covid and was lower than initially planned. The project was $32,390.00.

Unforeseen expenses not accounted for in the DSP

Poles replacement:

An expenditure of $ 16,426.00 was incurred to replace three poles.

Transformer's replacement:

An expense of $ 52,235.00 was incurred related to replacing twelve transformers.

Bollard Installation:

Following an ESA DDI (Electrical Safety Authority Due Diligence Inspection), CHEI installed bollards on the said location.

System Service:

CHEI, at the time of the DSP 2017 budget, forecast $25,000.00 for PCB Transformers Dated Before 1985 under System Access ($205,000.00) CHEI relocated that item to System Service.

$4,895.00 was incurred to dispose of one transformer contaminated.

General Plant:

CHEI's actual expense is higher by $29,880.00 than the DSP forecast in 2021.

Honeywell, through ORES, informs CHEI that the actual AMI (Advanced Metering Infrastructure) system must be replaced with a new one. The cost of replacement is $28,492.00.

CHEI also revamped its website to be more customer-friendly.

Contribute Capital:

CHEI's actual contributions for 2021 ($3,148.00) were not budgeted in the DSP forecast in 2020.

4.7 Summary of Planned Capital Expenditures (2022 to 2027)

Table ES-1 below provides the Historical Investments CHEI has made between 2018 and projected for 2022. Capital projects are detailed in section 4 of this report.

Table 27 - Planned Capital Investments by Year (Table ES-1)

	Test-1	Test	Test+1	Test+2	Test+3	Test+4
	2022	**2023**	**2024**	**2025**	**2026**	**2027**
CATEGORY	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
	$	$	$	$	$	$
System Access	331,300	40,000	42,000	53,000	42,000	65,000
System Renewal	112,225	107,050	90,650	72,550	62,700	58,850
System Service	6,000	6,000	6,000	6,000	0	0
General Plant	5,700	5,700	5,700	5,700	5,700	5,700
Total	**455,225**	**158,750**	**144,350**	**137,250**	**110,400**	**129,550**
Contributed Capital	-80,000	-10,000	-10,000	-10,000	-10,000	-10,000
Net Capital	**375,225**	**148,750**	**134,350**	**127,250**	**100,400**	**119,550**
System O&M	93,828	96,924	100,122	103,426	106,839	110,364

4.6 2022-2027 Capital Investments and Justification of Material Expenses

Table 28 – 2022 Capital Expenses vs. DSP

Description	**Project**	**Budget 2022**
Amounts are in dollars		
System Access	**Actual Year End 2020**	**System Renewal**
New O/H and U/G services 1855	$20,000	$23,000
Meters 1860	$5,000	$12,000
Subtotal	$25,000	$35,000
New Transformers (Inventory)	$18,000	$8,000
Subtotal	$18,000	$8,000
Service Area Pending		
Project Central Park		$50,000
(Transformers) -1850		
Project Central Park		$115,000
(Underground Cable and Labour) - 1845		
Project Central Park		$3,800
(Dip Pole and Labour) -1830		
Project Central Park		$4,500
(Primary Overhead Cable and Labour) - 1835		
Subtotal		$173,300
Service Area Pending		
Project Mélanie Construction Phase III		$38,000
(Transformers) -1850		
Project Mélanie Construction Phase		$65,000
(Underground Cable and Labour) 1845		
Project Mélanie Construction Phase III		$4,500
(Dip Pole and Labour) 1830		
Project Mélanie Construction Phase III		$7,500
(Primary Overhead Cable and Labour)-1835		
Subtotal		$115,000
Category Total	$43,000	$331,300
System Renewal		
Replacement of Existing Overhead in	$40000	$10,000
in Line Cut-outs and distribution switches		
Subtotal	$40,000	$10,000
Transformers Replacement		
Transformer Replacement # 418 (1850)		$6,525
Transformer Replacement # 432 (1850)		$9,750
Transformer Replacement # 448 (1850)		$6,950
Transformer Replacement # 452 (1850)		$9,750
Transformer Replacement # 461 (1850)		$4,250
Transformer Replacement # 470 (1850)		$5,650
Transformer Replacement # 481 (1850)		$5,650
Transformer Replacement # 502 (1850)		$6,950
Transformer Replacement # 509 (1850)		$4,250

Transformer Replacement # 518(1850)		$6,950
Transformer Replacement # 519(1850)		$6,950
Transformer Replacement # 527(1850)		$4,250
Transformer Replacement # 528(1850)		$6,950
Subtotal		$84,825
Pole Replacement		
Pole # 296		$5800
Pole # 441		$5800
Pole # 369		$5800
Subtotal		$17,400
Category Total	$40,000	$112,225
System Service		
PCB Transformers Dated Prior to 1985	$25,000	$6,000
Subtotal	$25,000	$6,000
General Plant		
Software - 1611	$3,000	$3,000
Office Equipment 1915	$1,200	$1,200
Computer & Hardware -1920	$1,500	$1,,500
Subtotal	$5,700	$5700
Category Total	$5,700	$5,700
Total Capital	**$113,700**	**$455,225**
Contributed Capital	**$ -**	**-$80,000**
Net Capital	**$113,700**	**$375,225**

2022 System Access

New Services:

Cost of customer requested new services related to new development and other customer requests.

CHEI forecast $23,000.00 in 2022, representing a $3,000.00 increase versus the DSP forecast in 2022.

Meter:

Cost of customer requested new services related to new development and other customer requests, the replacement of meter seal extension and defect meter.

CHEI forecast $12,000.00 in 2022, representing a $7,000.00 increase versus the DSP forecast in 2022.

Transformer Inventory:

CHEI forecast $8,000.00 in 2022, representing a $7,000.00 decrease versus the DSP forecast in 2022.

Pole Replacement:

Following the pole inspection CHEI will forecast $17,400.00 to replace three poles.

Unforeseen expenses not accounted for in the DSP

- Service Area Amendment Pending
- Faubourg Ste-Marie $115 000 (estimate)
- Central Park Subdivision$173 300 (estimate)

2022 System Renewal:

Replacement of Switch, Arrester, and Mounting Bracket at Individual pole-mount transformer location:

Porcelain fused cutouts and porcelain air gap type arrestors fail. Both devices create safety hazards when they fail in service. Typically, the fused cut-out will fail by breaking while being operated by a line crew and either causes a short circuit or leave the crew doing the switching hanging on to a live wire with no place to park the lead safely. Air gap lightning arrestors may fail explosively either in service and create a hazard for anyone in the immediate vicinity, either the public or a worker.

CHEI forecasted $40,000.00 for 2020 in its previous DSP. CHEI forecasts $10,000.

Transformer's replacement:

The forecast is $84,000.00 in 2022, which is related to replacing 13 aging transformers.

2022 System Service:

CHEI, at the time of the DSP 2017 budget, forecast $25,000.00 for PCB Transformers Dated Before 1985 under System Access ($25,000.00) CHEI relocated that item to System Service.

CHEI forecasts $6,000 for PCB transformer replacement.

General Plant:

CHEI forecasts the same amount of $5700 as in the previous DSP. The expense covers software, hardware, and office equipment.

Contribute Capital:

CHEI forecast for 2022 $80 000 versus DSP 2017 $0. The amount is an estimation of both Service Area Amendments.

Table 29 – 2023 Capital Expenses vs. DSP

Description	**BUDGET 2023**
Amounts are in dollars	
System Access	
New O/H and U/G services 1855	$20000
Meters 1860	$12000
Subtotal	$32000
New Transformers (Inventory)	$8000
Subtotal	$8000
Category Total	$40000
System Renewal	
Replacement of Existing Overhead in Line Cut-outs and distribution switches	$10,000
Subtotal	$10,000
Transformers Replacement	
Transformer Replacement # 531(1850)	$5,650
Transformer Replacement # 533(1850)	$4,250
Transformer Replacement # 535(1850)	$6,950
Transformer Replacement # 536(1850)	$5,650
Transformer Replacement # 537(1850)	$4,250
Transformer Replacement # 539(1850)	$6,950
Transformer Replacement # 541(1850)	$6,950
Transformer Replacement # 543(1850)	$5,650
Transformer Replacement # 545(1850)	$5,650
Transformer Replacement # 546(1850)	$6,950
Transformer Replacement # 548(1850) Transformer Bank	$10,250
Transformer Replacement # 551(1850)	$4,250
Subtotal	$73,400
Pole Replacement	
Pole # 1	$8,750
Pole # 258	$8,500
Pole # 304	$6,400
Subtotal	$23,650
Category Total	$107,050
System Service	
PCB Transformers Dated Prior to 1985	$6,000
Subtotal	$6,000
Category Total	$6,000
General Plant	

Software - 1611		$3,000
Office Equipment 1915		$1,200
Computer & Hardware -1920		$1,500
	Subtotal	$5,700
Category Total		$5,700
Total Capital		$158,750
Contributed Capital		-$10,000
Net Capital		$148,750

2023 System Access

New Services:

Cost of customer requested new services related to new development and other customer requests.

CHEI forecast $20 000.00 in 2023.

Meter:

Cost of customer requested new services related to new development and other customer requests, the replacement of meter seal extension and defect meter.

CHEI forecast $12 000.00 in 2023.

Transformer Inventory:

CHEI forecast $8 000.00 to maintain inventory up to date to respond to a failure transformer or a request from a customer for a new service

CHEI forecast $8 000.00 in 2023

2023 System Renewal:

Replacement of Switch, Arrester, and Mounting Bracket at Individual pole-mount transformer location:

Porcelain fused cutouts and porcelain air gap type arrestors fail. Both devices create safety hazards when they fail in service. Typically, the fused cut-out will fail by breaking while being operated by a line crew and either causes a short circuit or leave the crew doing the switching hanging on to a live wire with no place to park the lead safely. Air gap lightning arrestors may fail explosively either in service and create a hazard for anyone in the immediate vicinity, either the general public or a worker.

CHEI forecast $10 000.00 in 2023,

Transformer's replacement:

CHEI forecast $73,400 in 2023 to replace 14 aging transformers, including transformer bank.

2023 System Service:

CHEI, at the time of the DSP 2017 budget, forecast $25,000.00 for PCB Transformers Dated Before 1985 under System Access ($25,000.00) CHEI relocated that item to System Service.

CHEI forecasts an amount of $6 000.00 for 2023.

General Plant:

CHEI will forecast $5 000.00 in 2023 to cover expenses in software, hardware, and office equipment.

Contribute Capital:

CHEI's forecast -($10 000.00) in 2023.

Table 30 – 2024 Forecasted Capital Expenses

Description		**2024 Budget**
New O/H and U/G services 1855		$20,000
Meters 1860		$12,000
	Subtotal	$32,000
New Transformers (Inventory)		$10,000
	Subtotal	$10,000
Category Total		$42,000
Replacement of Existing Overhead in Line Cut outs and distribution switches		$10,000
	Subtotal	$10,000
Transformers Replacement		
Transformer Replacement # 402(1850)		$4,750
Transformer Replacement # 404(1850)		$6,150
Transformer Replacement # 407(1850)		$4,750
Transformer Replacement # 408(1850)		$6,150
Transformer Replacement # 409(1850)		$4,750
Transformer Replacement # 410(1850)		$6,150
Transformer Replacement # 411(1850)		$6,150
Transformer Replacement # 413(1850)		$7,450
Transformer Replacement # 423(1850)		$7,450
Transformer Replacement # 451(1850)		$4,750
Transformer Replacement # 463 (1850)		$4,750
	Subtotal	$63,250
Pole Replacement		
Pole # 296		$5,800
Pole # 441		$5,800
Pole # 369		$5,800
	Subtotal	$17,400
Category Total		$90,650
PCB Transformers Dated Prior to 1985		$6,000
	Subtotal	$6,000
Category Total		$6,000
Software - 1611		$3,000
Office Equipment 1915		$1,200
Computer & Hardware -1920		$1,500
	Subtotal	$5,700
Category Total		$5,700
Total Capital		$144,350
Contributed Capital		-$10,000
Net Capital		$134,350

Table 31 – 2025 Forecasted Capital Expenses

Description		**2025 Budget**
System Access		
New O/H and U/G services 1855		$20,000
Meters 1860		$12,000
	Subtotal	$32,000
New Transformers (Inventory)		$10,000
	Subtotal	$10,000
Distribution Map - Revision (Stantec - Sproule)		
1845 - Underground		$2,500
1835 - Overhead		$2,500
	Subtotal	$5,000
Pole Testing		
Asset Management		$6,000
	Subtotal	$6,000
Category Total		$53,000
System Renewal		
Replacement of Existing Overhead in Line Cut outs and distribution switches		$10,000
	Subtotal	$10,000
Transformers Replacement		
Transformer Replacement # 500 (1850) Bank 3x100		$15,000
Transformer Replacement # 466(1850)		$4,750
Transformer Replacement # 468(1850)		$4,750
Transformer Replacement # 472(1850)		$6,150
Transformer Replacement # 526(1850)		$8,250
	Subtotal	$38,900
Pole Replacement		
Pole # 1		$8,750
Pole # 258		$8,500
Pole # 304		$6,400
	Subtotal	$23,650
Category Total		$72,550
System Service		
PCB Transformers Dated Prior to 1985		$6,000
	Subtotal	$6,000
Category Total		$6,000
General Plant		
Software - 1611		$3,000
Office Equipment 1915		$1,200
Computer & Hardware -1920		$1,500
	Subtotal	$5,700
Category Total		$5,700
Total Capital		$137,250
Contributed Capital		-$10,000
Net Capital		$127,250

Table 32 – 2026 Forecasted Capital Expenses

Description		**2026 Budget**
System Access		
New O/H and U/G services 1855		$20,000
Meters 1860		$12,000
	Subtotal	$32,000
New Transformers (Inventory)		$10,000
	Subtotal	$10,000
Category Total		$42,000
System Renewal		
Replacement of Existing Overhead in Line Cut outs and distribution switches		$10,000
	Subtotal	$10,000
Transformers Replacement		
Transformer Replacement # 443 (1850) 3X 50KVA		$17,850
Transformer Replacement # 479 (Transfo Bank (1850)		$16,850
Subtotal		$34,700
Pole Replacement		
Pole #		$6,000
Pole #		$6,000
Pole #		$6,000
	Subtotal	$18,000
Category Total		$62,700
System Service		
No Project		
General Plant		
Software - 1611		$3,000
Office Equipment 1915		$1,200
Computer & Hardware -1920		$1,500
	Subtotal	$5,700
Category Total		$5,700
Total Capital		$110,400
Contributed Capital		-$10,000
Net Capital		$100,400

Table 33 – 2027 Forecasted Capital Expenses

System Access	**2027Budget**
New O/H and U/G services 1855	$20,000
Meters 1860 - (Stock)	$12,000
Meters 1860 - Reverification Year 2024	$25,000
New Transformers Inventory	$8,000
Subtotal	$65,000
Category Total	$65,000
System Renewal	
Replacement of Existing Overhead in Line Cut outs and distribution switches	$10,000
Subtotal	$10,000
Transformer Replacement # 459 Transfo Bank (1850)	$17,850
Transformer Replacement # 500(1850) Transfo Bank	$17,850
Transformer Replacement # 526(1850) Transfo Bank	$13,000
Subtotal	$30,850
Pole Replacement	
Pole #	$6,000
Pole #	$6,000
Pole #	$6,000
Subtotal	$18,000
Category Total	$58,850
System Service	
NO Item	
General Plant	
Software - 1611	$3,000
Office Equipment 1915	$1,200
Computer & Hardware -1920	$1,500
Subtotal	$5,700
Category Total	$5,700
Total Capital	$129,550
Contribute Capital	-$10,000
Net Capital	$119,550

APPENDICES

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A	Regional Report

APPENDICES

List of Appendices

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

NEEDS ASSESSMENT REPORT

Region: St Lawrence

Date: September 15, 2021

Prepared by: St Lawrence Region Study Team

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the St Lawrence Region and to recommend which need may be a) directly addressed by developing a preferred plan as part of NA phase and b) identify needs requiring further assessment and/or regional coordination. The results reported in this Needs Assessment are based on the input and information provided by the Study Team for this region.

The Study Team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, “the Authors”) shall not, under any circumstances whatsoever, be liable to each other, to any third party for whom the Needs Assessment Report was prepared (“the Intended Third Parties”) or to any other third party reading or receiving the Needs Assessment Report (“the Other Third Parties”). The Authors, Intended Third Parties and Other Third Parties acknowledge and agree that: (a) the Authors make no representations or warranties (express, implied, statutory or otherwise) as to this document or its contents, including, without limitation, the accuracy or completeness of the information therein; (b) the Authors, Intended Third Parties and Other Third Parties and their respective employees, directors and agents (the “Representatives”) shall be responsible for their respective use of the document and any conclusions derived from its contents; (c) and the Authors will not be liable for any damages resulting from or in any way related to the reliance on, acceptance or use of the document or its contents by the Authors, Intended Third Parties or Other Third Parties or their respective Representatives.

Executive Summary

REGION St Lawrence Region (the "Region")

LEAD Hydro One Networks Inc. ("HONI")

START DATE: JULY 15, 2021 **END DATE:** September 15, 2021

1. INTRODUCTION

The first cycle of the Regional Planning process for the St Lawrence Region was completed in April 2016 with the publication of the Needs Assessment Report. As no further regional coordination or planning was required, the NA identified needs to be addressed between relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

This is the second cycle of regional planning and the purpose of this Needs Assessment ("NA") is a) to identify any new needs and/or to reaffirm needs identified in the previous St Lawrence Regional Planning cycle and b) recommend which need may be i) addressed by developing a preferred plan as part of NA phase and ii) identify needs requiring further assessment and/or regional coordination.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the regional planning cycle should be triggered at least every five years. In light of these timelines, the 2nd Regional Planning cycle was triggered for St Lawrence Region.

3. SCOPE OF NEEDS ASSESSMENT

The assessment's primary objective is to identify the electrical infrastructure needs over the study period, develop options and recommend which needs require further regional coordination.

The scope of this NA includes:

- Review and reaffirm needs/plans identified in the previous NA; and
- Identification and assessment of system capacity, reliability, operation, and aging infrastructure needs in the region: and
- Develop options for need(s) and/or a preferred plan or recommend which needs require further assessment/regional coordination.

The Study Team may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), IRRP and RIP, based on updated information available at that time.

The planning horizons of regional planning is considered over a 20 year time period; however, focus of this NA assessment is over the next 10 years.

4. INPUTS/DATA

The Study Team representatives from Local Distribution Companies ("LDC"), the Independent Electricity System Operator ("IESO"), and Hydro One provided input and relevant information for this Region regarding capacity needs, reliability needs, operational issues, and major assets/facilities approaching end-of-life ("EOL"). Hydro One has also researched to find community energy plans in the region. No energy plans have been identified that would impact the assessment undertaken as part of this report. The working group will monitor and take them into consideration as they are developed.

5. ASSESSMENT METHODOLOGY

The assessment methodology include review of planning information such as load forecast, conservation and demand management ("CDM") forecast and available distributed generation ("DG") information, any system reliability and operation issues, and major high voltage equipment identified to be at or near the end of their life.

A technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy;
- Reliability needs and operational concerns; and
- Any major high voltage equipment reaching the end of its life.

6. NEEDS

I. Update of identified needs from previous cycle

a. Chesterville TS was identified to have missed customer delivery point target (frequency of interruption) due to momentary outages. After reviewing the root causes, it is recommended that no immediate action is required and the delivery point performance will continue to be monitored. Update is provided in Section **7.**

II. Newly identified needs in the region

a. Line / Station Capacity

No new transmission line or station capacity issues identified for the area.

b. Aging Infrastructure Transformer Station and Transmission Circuit Replacements

i. L22H: replacement of conductor, shieldwire, insulator and tower work (2026)

7. RECOMMENDATIONS

The Study Team recommends that Replacement of end of life asset identified in above in 6 II b. does not require further regional coordination (see further details in Section 7.1). The implementation and execution plan for these needs will be coordinated by Hydro One with affected LDCs and/or customers. This assessment did not identify any other needs, therefore no further regional coordination required.

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List of Tables and Figures

1 INTRODUCTION

The first cycle of the Regional Planning process for the St Lawrence Region was completed in April 2016 with the publication of the Needs Assessment ("NA") Report [1].

The purpose of this Needs Assessment ("NA") is to identify new needs and to reconfirm and update any needs identified in the previous St Lawrence regional planning cycle.

This report was prepared by the St Lawrence Region Study Team ("Study Team"), led by Hydro One Networks Inc. Participants of the Study Team are listed below in Table 1. The report presents the results of the assessment based on information provided by the Hydro One, the Local Distribution Companies ("LDC") and the Independent Electricity System Operator ("IESO").

Table 1: St Lawrence Region Study Team Participants

Niagara Study Team
Hydro One Networks Inc. (Lead Transmitter)
Cooperative Hydro Embrun Inc.
Hydro One Distribution
Rideau St Lawrence Distribution Inc.
Independent Electricity System Operator

2 REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. As such, the 2nd Regional Planning cycle was triggered for the St Lawrence region

3 SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the St Lawrence region and includes:

- Review the status of needs/plans identified in the previous NA and
- Identification and assessment of any new needs (e.g. system capacity, reliability, operation, and aging infrastructure)

The Study Team may identify additional needs during the next phases of the regional planning process, namely Scoping Assessment ("SA"), Local Planning ("LP"), IRRP, and/or RIP.

4 REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The St Lawrence Region covers the southeastern part of Ontario bordering the St Lawrence River. The region starts at the Gananoque in the West and extends to the inter-provincial boundary with Quebec in the East.

The western part of the region is supplied from Hydro One owned stations connected to the 230kV network. The reminder of the region is supplied from Hydro One stations connected to the 115kV network except for St Lawrence TS which is supplied from 230kV.

The City of Cornwall is supplied by Fortis Ontario with transmission lines from Quebec and is not included in this Region. A map of the region is shown below in Figure 1.

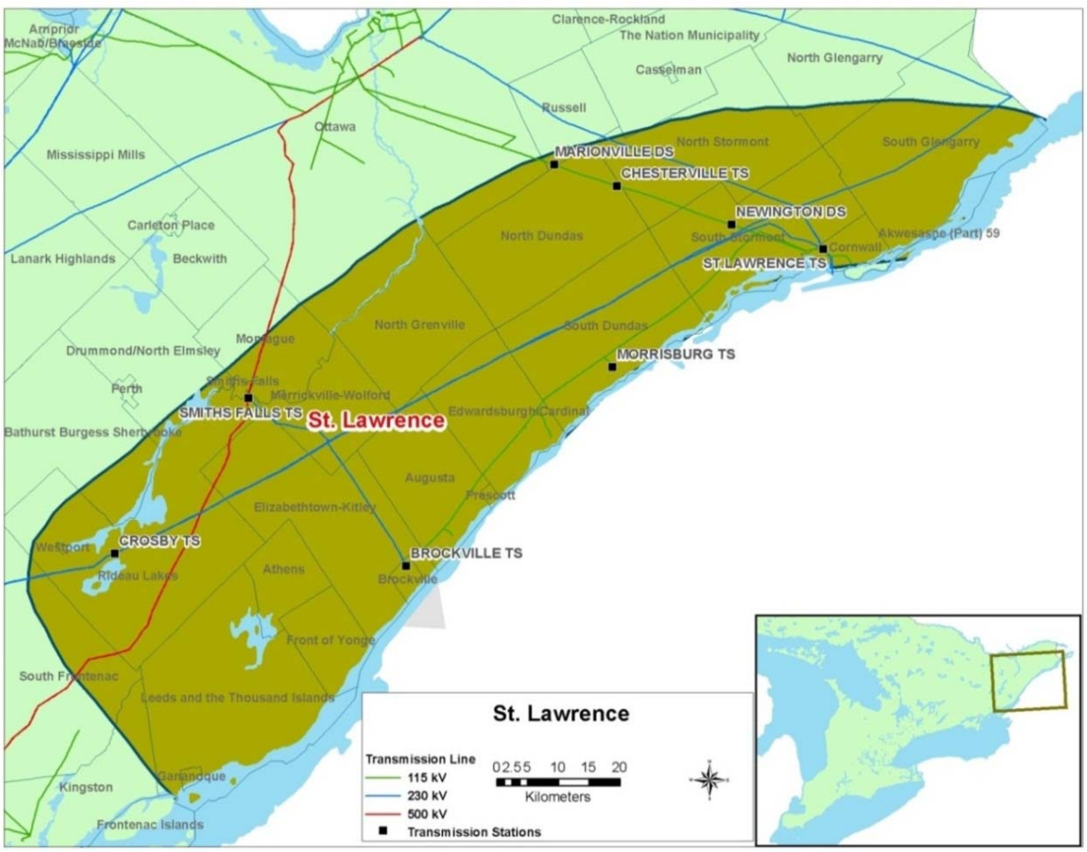

Figure 1: Map of St Lawrence Regional Planning Area

Electrical supply for this region is provided through a network of 230kV and 115kV transmission circuits. The major source of supply for this region is OPG's Saunders Hydro Electric station which connects to St Lawrence TS 230kV yard.

The St Lawrence Region is connected to the Greater Ottawa Region through 230kV circuits L24A and B31L. Circuit B31L also provides an interconnection between the Provinces of Ontario and Quebec. In addition, 115kV circuit L2M also connects St Lawrence to the Greater Ottawa Region, however this connection is normally open and is only used for load transfers between the two areas in case of system need. The Region is also connected to the Peterborough to Kingston Region through 230kV circuits L20H, L21H, and L22H.

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Figure 2 and 3.

- St Lawrence TS is the major transmission station for the region and connects to the main source of supply for the area, Saunders GS via four 230kV circuits. Also connecting to the 230kV yard of the station are two International Power Lines (IPL). These IPLs connect Ontario to the State of New York and power exchange across the IPLs are regulated using two phase shifting transformers. The station also has two 230kV/115kV 250MVA autotransformers to connect the 230kV and 115kV networks.

- Seven step-down transformer stations supply the St Lawrence Area load. At 230kV: Brockville TS, Crosby TS, Smith Falls TS, and St Lawrence TS. At 115kV: Chesterville TS, Morrisburg TS, and Newington DS.

- Two Customer Transformer Stations (CTS) are supplied in the Region from the 115kV network: Dyno Nobel Nitrogen and Enbridge Pipeline Cardinal.

- Another source of supply to the area is an existing transmission connected generating station, Cardinal Power CGS with maximum output 134MW (summer) and 184MW (winter) [4].

The circuits and stations of the area are summarized in the Table 2 below:

Table 2. Transmission Station and Circuits in the St Lawrence Region

115kV circuits	230kV circuits	Hydro One Transformer Stations
L1MB, L2M, L5C[1]	L20H, L21H, L22H, L24A[2], B31L[2], L33P[3], L34P[3]	Brockville TS, Chesterville TS, Crosby TS Morrisburg TS, Newington DS, Smith Falls TS St Lawrence TS*

*Stations with Autotransformers installed

[1] L5C is normally o/s, and used as a backup supply for the City of Cornwall.

[2] L24A and B31L connect to St Lawrence TS but do not have load customers connection.

[3] IPLs circuits.

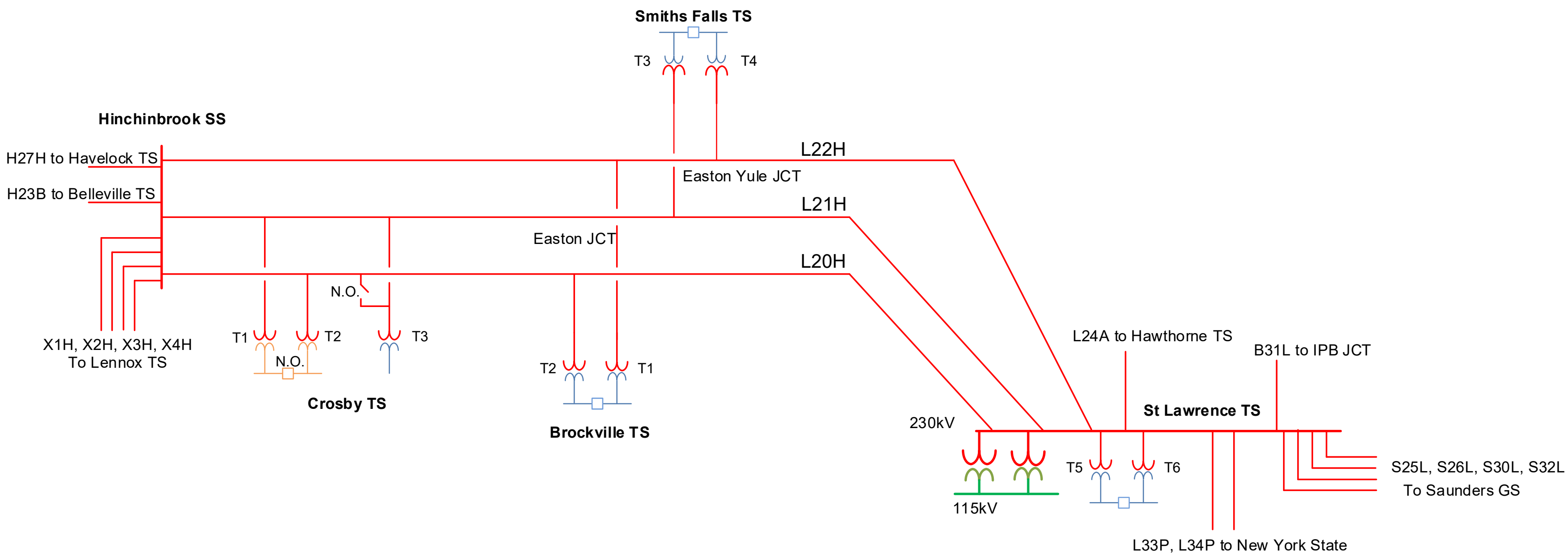

Figure 2: Single Line Diagram 230kV St Lawrence Planning Area

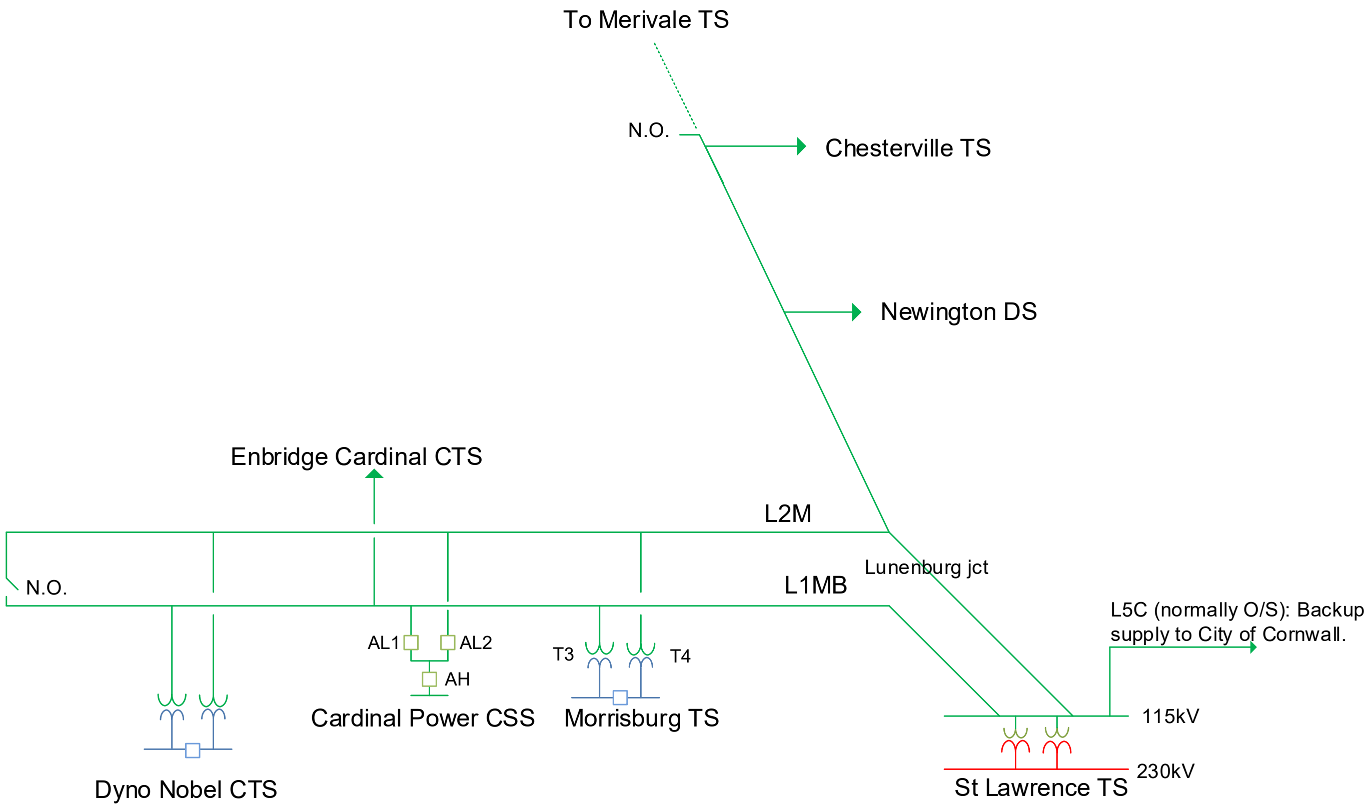

Figure 3: Single Line Diagram 115kV St Lawrence Planning Area

5 INPUTS AND DATA

Study Team participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the St Lawrence Region NA. The information provided includes the following:

- St Lawrence Load Forecast for all supply stations;
- Known capacity and reliability needs, operating issues, and/or major assets approaching the end of life ("EOL"); and
- Planned/foreseen transmission and distribution investments that are relevant to regional planning for the St Lawrence Region.
- Hydro One has also researched to find community energy plans in the region. No energy plans have been identified that would impact the assessment undertaken as part of this report. The working group will monitor and take them into consideration as they are developed

6 ASSESSMENT METHODOLOGY

The following methodology and assumptions are made in this Needs Assessment:

Information gathering included:

i. Load forecast: The LDCs provided load forecasts for all the stations supplying their loads in the St Lawrence region for the 10 year study period. The IESO provided a Conservation and Demand Management ("CDM") and Distributed Generation ("DG") forecast for the St Lawrence region. The region's extreme winter and summer non-coincident peak gross load forecasts for each station were prepared by applying the LDC load forecast growth rates to the actual 2020 summer and 2020 winter peak extreme weather corrected loads. The extreme summer / winter weather correction factors were provided by Hydro One. The net extreme weather summer / winter load forecasts were produced by reducing the gross load forecasts for each station by the percentage CDM and then by the amount of effective DG capacity provided by the IESO for that station. It is to be noted that in the long-term (10+ year) time frame, contracts for existing DG resources in the region begin to expire, at which point the load forecast indicates a decreasing contribution from local DG resources, and an increase in net demand. These extreme weather corrected net summer / winter load forecast for the individual stations in the St Lawrence region is given in Appendix A;

ii. Relevant information regarding system reliability and operational issues in the region; and

iii. List of major HV transmission equipment planned and/or identified to be refurbished and/or replaced due to the end of life which is relevant for regional planning purposes. This includes HV transformers, autotransformers, HV Breakers, HV underground cables and overhead lines.

A technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy;
- System reliability and operational concerns;
- Any major high voltage equipment reaching the end of life;
- Generating station Saunders GS was assumed to generate at its average 98% of time dependable hydro generation level which is 467MW for winter and 511MW for summer.
- No power exchanges on the Ontario Eastern interconnections.
- Load forecast data was requested from industrial customers in the region. Where data was not provided, the load was assumed to be consistent with historical loads.
- The Region is winter peaking so this assessment is based on winter peak loads. However sensitivity analysis was also done using summer peak loads

7 NEEDS

This section describes emerging needs identified in the St Lawrence Region, and also reviews the near, mid, and long-term needs already identified in the previous regional planning cycle. A contingency analysis was performed for the region using the load forecast developed and no new system needs were identified.

The status of the previously identified needs is summarized in Table 2 below.

Table 3: Needs Identified in the Previous Regional Planning Cycle

Type of Needs identified in the previous RP cycle	Needs Details	Current Status
Chesterville TS delivery point performance	Missed customer delivery point target (frequency of interruption) due to momentary outages (due to severe weather patterns). Action: Hydro One will review and monitor its supply point performance at Chesterville TS to determine if corrective measures are required.	In 2019, there were interruptions due to equipment issues at another station supplied by circuit L2M. Because of the nature of these interruptions, they can be considered as isolated incidents, and performance is expected to return to normal. Hydro One will continue to monitor the performance of delivery points within the region.

7.1 End-Of-Life (EOL) Equipment Needs

Hydro One have reviewed and provided high voltage asset information under the following categories that have been identified at this time and are likely to be replaced over the next 10 years:

- Autotransformers
- Power transformers
- HV breakers
- Transmission line conductor

The end-of-life assessment for the above high voltage equipment typically included consideration of the following options:

1. Replacing equipment with similar equipment and built to current standards (i.e., "like-for-like" replacement);
2. Replacing equipment with similar equipment of higher / lower ratings i.e. right sizing opportunity and built to current standards;
3. Replacing equipment with lower ratings and built to current standards by transferring some load to other existing facilities;
4. Eliminating equipment by transferring all of the load to other existing facilities;

In addition, from Hydro One's perspective as a facility owner and operator of its transmission equipment, do nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance cost and longer duration of customer outages.

Accordingly, the following major high voltage equipment has been identified as approaching its end of life over the next 10 years and assessed for right sizing opportunity.

The Study Team recommended continuation of these end of life asset replacement as per the plan. As per Section 7.2, under the assumptions of Regional Planning, circuit L22H is adequate over the study period. However the circuit is also used for bulk power transfers across Ontario. Determination of whether upgrade to the capacity of this section of circuit L22H is required for power bulk transfer will be reviewed as part of Bulk Planning studies completed by IESO and Hydro One.

Station/Circuit	Proposed I/S	Description
Circuit L22H	**2026**	• This investment refurbishes a total of 65 km of 230 kV circuit L22H between Easton JCT X Hinchinbrook North JCT. Work in this project includes the replacement of conductors, shieldwire, insulators and refurbishment of lattice steel structures.

In addition to the plan mentioned above, Hydro One is in the process of replacing the two phase shifting transformers at St Lawrence TS which are used to control the power flow exchange with New York across the IPL circuits.

7.2 Station and Transmission Capacity Needs in the St Lawrence Region

The following Station and Transmission supply capacities have been reviewed and no needs have been identified in the St Lawrence region during the study period of 2021 to 2031.

7.2.1 230/115 kV Autotransformers

The 230/115 kV autotransformers at St Lawrence TS supplying the Region are within their ratings and are adequate to supply the forecasted load over the study period.

7.2.2 230 kV Transmission Lines

The 230kV circuits supplying the Region are adequate over the study period for the loss of a single 230kV circuit in the Region under the study assumptions of the Needs Assessment.

As discussed in previously Section 4, St Lawrence TS is connected to Saunders generating station, to the State of New York through two IPLs, and to Province Quebec interconnection through circuit B31L (Beauharnois generating station). As a results of these connections, many operating scenarios and system conditions can influence the flows on circuits L20H, L21H, and L22H. These scenarios are evaluated under Bulk planning and are not part of the scope of the Needs Assessment. However it should be noted that there is a generation rejection scheme in place that can runback Saunders GS and/or Beauharnois GS under post-contingency conditions. This scheme ensures that the St Lawrence to Hinchinbrook TS lines are not overloaded under peak summer conditions.

7.2.3 115kV Transmission Lines

The 115kV circuits supplying the Region are adequate over the study period for the loss of a single 115kV circuit in the Region under the study assumptions of the Needs Assessment.

7.2.4 230 kV and 115 kV Connection Facilities

A station capacity assessment was performed over the study period for the 230 kV and 115 kV TSs in the Region using either the summer or winter station peak load forecasts as appropriate that were provided by the study team. The results are as follows:

a) Transformer stations

All the transformer stations in the region are forecasted to remain within their normal supply capacity during the study period. Capacity needs for these stations will be reviewed in the next planning cycle.

Depending on the load growth and the future decisions on contracts for distributed energy resources connected to the station, the capacity of some stations could be reached in the long term (10+ years). The Working Group will continue to monitor the load growth at the stations and will re-evaluate the capacity at the next planning cycle.

7.2.5 115kV System

The distributed energy resources (DER) connected to the 115kV stations of the area and the 115kV generating station have resulted in the following identified in the Cardinal Power G3 Expansion SIA/CIA [3, 4]:

a) Reverse Power Flow at Morrisburg TS and Dyno Nobel CTS

At Morrisburg TS, under light load condition with high output for DER and 115kV connected generation, a reverse power flow issue was identified. This situation occurs if one of the line breakers at Cardinal Power has an inadvertent opening (IBO). This IBO results in all of Cardinal Power's generation being sent to one line, which causes reverse power at Morrisburg TS beyond its maximum limit. Additional generation connection has been restricted at Morrisburg TS to manage the reverse power flow at the station.

Under the same conditions mentioned above, an IBO at Cardinal Power can also result in power flow through the Dyno Nobel CTS transformers to exceed their rating.

For Morrisburg TS and Dyno Nobel CTS transformer loading issues, Cardinal Power run back scheme is triggered to reduce the flows to within equipment ratings as it was outlined in the SIA and CIA [3, 4]. No further action is recommended within the scope of this regional planning.

b) L2M/L1MB

Under light load condition and with all distributed generation in the area and the Cardinal Power generation at maximum output the section of the L1MB/L2M line between St Lawrence to Lunenburg JCT can be loaded beyond its short time emergency (STE) rating for loss of either circuit [3,4].

To manage the situation, Morrisburg TS has been restricted to accept new generation connection. In addition, there is Cardinal Power's runback scheme which will reduce the plant output following the loss of either circuit and hence reduce the post-contingency loading on either of the L1MB/L2M lines. However since the lines could be loaded beyond their STE, measures such generation re-dispatch is implemented by the IESO as per the Cardinal Power G3 Expansion studies [3, 4].

7.3 System Reliability, Operation and Restoration Review

No new significant system reliability and operating issues identified for this Region. Based on the net load forecast, the loss of one element will not result in load interruption greater than 150MW. The maximum load interrupted by configuration due to the loss of two elements is below the load loss limit of 600MW by the end of the 10-year study period.

8 CONCLUSION AND RECOMMENDATIONS

The Study Team recommends that refurbishment of L22H between Easton JCT X Hinchinbrook North JCT does not require further regional coordination. The implementation and execution plan for this need will be coordinated by Hydro One with affected LDCs. However, IESO led Bulk Planning Studies will review and confirm if there are any changes required to Hydro One refurbishment plan before the end of Q3 2022. No other needs have been identified that require regional coordination.

9 REFERENCES

1. Needs Assessment Report – St Lawrence – April 2016
2. IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0
3. Cardinal Power 15MW Plant Expansion SIA (2011-432)
4. Cardinal Power 15MW Plant Expansion CIA

Appendix A: Extreme Weather Adjusted Non-Coincident Summer / Winter Load Forecast

Station		LTR (MW)	Type	Near Term Forecast (MW)					Medium Term Forecast (MW)					Long Term Forecast (MW)				
				2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2033	2035	2037	2039
Brockville TS	T1/T2	166.2	Load	125.3	130.2	134.6	138.1	140.8	141.9	143.2	144.5	145.7	146.9	148.0	150.2	152.6	154.9	157.2
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.5	-45.3	-45.3	-45.3
			CDM	0.8	1.8	2.8	3.6	4.2	4.4	4.6	4.7	5.2	5.5	5.6	5.8	7.1	6.8	6.4
			NET	124.5	128.4	131.8	134.5	136.7	137.5	138.6	139.8	140.5	141.4	142.4	144.9	190.8	193.4	196.0
			NET_DG	124.5	128.4	131.8	134.5	136.7	137.5	138.6	139.8	140.5	141.4	142.4	144.4	147.1	149.6	152.2
Chesterville TS	T1/T2	56.7	Load	39.5	39.8	40.1	40.4	40.6	40.9	41.2	41.4	41.7	41.9	42.1	42.6	43.0	43.4	43.8
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.1	-0.1	-0.4
			CDM	0.3	0.5	0.8	1.0	1.2	1.3	1.3	1.4	1.5	1.6	1.6	1.6	1.6	1.5	1.4
			NET	39.2	39.2	39.3	39.3	39.4	39.6	39.9	40.1	40.2	40.3	40.5	40.9	41.6	42.1	42.8
			NET_DG	39.2	39.2	39.3	39.3	39.4	39.6	39.9	40.1	40.2	40.3	40.5	40.9	41.5	42.0	42.4
Crosby TS	T1/T2	65.6	Load	13.8	13.9	14.0	14.1	14.2	14.3	14.4	14.5	14.6	14.7	14.8	15.0	15.2	15.4	15.6
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			CDM	0.1	0.2	0.3	0.4	0.4	0.4	0.5	0.5	0.5	0.6	0.6	0.6	0.5	0.5	0.5
			NET	13.7	13.7	13.7	13.8	13.8	13.9	14.0	14.1	14.1	14.2	14.3	14.4	14.7	14.9	15.1
			NET_DG	13.7	13.7	13.7	13.8	13.8	13.9	14.0	14.1	14.1	14.2	14.3	14.4	14.7	14.9	15.1
Crosby TS	T3	75.0	Load	22.7	23.0	23.2	23.4	23.6	23.7	24.0	24.2	24.3	24.5	24.7	25.1	25.4	25.8	26.1
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			CDM	0.2	0.3	0.5	0.6	0.7	0.7	0.8	0.8	0.9	0.9	0.9	1.0	0.9	0.9	0.8
			NET	22.6	22.6	22.7	22.8	22.9	23.0	23.2	23.4	23.5	23.6	23.8	24.1	24.5	24.9	25.3
			NET_DG	22.6	22.6	22.7	22.8	22.9	23.0	23.2	23.4	23.5	23.6	23.8	24.1	24.5	24.9	25.3
Morrisburg TS	T3/T4	127.2	Load	56.3	59.1	62.0	62.6	63.2	63.7	64.4	65.0	65.7	66.3	66.8	68.1	69.3	70.6	71.9
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-11.3	-11.3	-11.3	-11.3
			CDM	0.4	0.8	1.3	1.6	1.9	2.0	2.1	2.1	2.3	2.5	2.5	3.1	2.9	2.8	2.6
			NET	55.9	58.3	60.8	61.0	61.3	61.8	62.3	62.9	63.4	63.8	64.3	76.4	77.8	79.1	80.6
			NET_DG	55.9	58.3	60.8	61.0	61.3	61.8	62.3	62.9	63.4	63.8	64.3	65.5	66.8	68.2	69.6
Newington DS	-	13.5	Load	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.5	2.5	2.5
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			CDM	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
			NET	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4
			NET_DG	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4
Smiths Falls TS	T3/T4	176.4	Load	114.1	117.4	119.7	120.4	121.1	121.9	122.7	123.6	124.4	125.1	125.8	127.3	128.7	130.1	131.5
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			CDM	0.8	1.6	2.5	3.1	3.6	3.8	4.0	4.0	4.4	4.7	4.8	4.9	4.6	4.4	4.2
			NET	113.3	115.8	117.2	117.3	117.5	118.1	118.8	119.5	120.0	120.4	121.0	122.4	124.1	125.7	127.4
			NET_DG	113.3	115.8	117.2	117.3	117.5	118.1	118.8	119.5	120.0	120.4	121.0	122.4	124.1	125.7	127.4
St. Lawrence TS	T5/T6	183.5	Load	40.1	40.4	40.7	40.9	41.1	41.3	41.5	41.8	42.0	42.1	42.3	42.7	43.0	43.3	43.7
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			CDM	0.3	0.5	0.8	1.1	1.2	1.3	1.3	1.4	1.5	1.6	1.6	1.7	1.5	1.5	1.4
			NET	39.8	39.8	39.9	39.8	39.9	40.0	40.2	40.4	40.5	40.6	40.7	41.0	41.5	41.9	42.3
			NET_DG	39.8	39.8	39.9	39.8	39.9	40.0	40.2	40.4	40.5	40.6	40.7	41.0	41.5	41.9	42.3

Table A.1: St Lawrence Region Winter Non-Coincident Load Forecast

Please note: In the table above NET assumes DG contracts begin to expire and NET_DG assumes DGs remain.

Transformer Station		LTR (MW)	Type	Near Term Forecast (MW)					Medium Term Forecast (MW)					Long Term Forecast (MW)				
				2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2033	2035	2037	2039
Brockville TS	T1/T2	145.6	Load	97.3	101.4	105.2	108.0	110.2	111.2	112.1	113.1	114.0	114.9	115.8	117.6	119.5	121.3	123.2
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-4.5	-4.6	-49.5	-49.5
			CDM	0.5	1.6	2.8	3.7	4.4	4.6	5.0	5.1	5.3	5.3	5.2	5.2	4.8	6.4	6.4
			NET	96.8	99.8	102.4	104.3	105.9	106.5	107.1	107.9	108.8	109.6	110.6	117.0	119.3	164.3	166.3
			NET_DG	96.8	99.8	102.4	104.3	105.9	106.5	107.1	107.9	108.8	109.6	110.6	112.6	114.9	116.7	118.6
Chesterville TS	T1/T2	52.9	Load	36.1	36.6	37.0	37.2	37.3	37.6	37.9	38.1	38.4	38.6	38.8	39.2	39.6	40.0	40.3
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.1	-3.0	-3.0	-3.2
			CDM	0.2	0.6	1.0	1.3	1.5	1.6	1.7	1.7	1.8	1.8	1.7	1.7	1.7	1.6	1.6
			NET	35.9	36.0	36.0	35.9	35.9	36.0	36.2	36.4	36.6	36.8	37.1	37.6	40.9	41.3	42.0
			NET_DG	35.9	36.0	36.0	35.9	35.9	36.0	36.2	36.4	36.6	36.8	37.0	37.5	38.0	38.5	38.9
Crosby TS	T1/T2	57.6	Load	12.0	12.1	12.3	12.3	12.4	12.5	12.6	12.7	12.8	12.9	13.0	13.1	13.3	13.4	13.6
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-3.0	-3.0	-3.0
			CDM	0.1	0.2	0.3	0.4	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
			NET	11.9	11.9	11.9	11.9	11.9	12.0	12.1	12.1	12.2	12.3	12.4	12.6	15.6	15.8	16.0
			NET_DG	11.9	11.9	11.9	11.9	11.9	12.0	12.1	12.1	12.2	12.3	12.4	12.6	12.8	12.9	13.1
Crosby TS	T3	75.0	Load	21.6	21.9	22.2	22.4	22.5	22.7	22.9	23.1	23.3	23.4	23.6	23.9	24.3	24.6	24.9
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-4.1	-5.5	-5.5	-5.5
			CDM	0.1	0.4	0.6	0.8	0.9	0.9	1.0	1.1	1.1	1.1	1.1	1.2	1.2	1.1	1.1
			NET	21.5	21.5	21.6	21.6	21.6	21.7	21.9	22.0	22.2	22.3	22.5	26.9	28.6	29.0	29.3
			NET_DG	21.5	21.5	21.6	21.6	21.6	21.7	21.9	22.0	22.2	22.3	22.5	22.9	23.3	23.7	24.0
Morrisburg TS	T3/T4	115.2	Load	48.7	51.3	53.9	54.4	54.9	55.4	55.9	56.5	57.0	57.5	58.1	59.2	60.3	61.4	62.4
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-6.8	-6.8	-6.8
			CDM	0.2	0.8	1.4	1.8	2.2	2.3	2.5	2.6	2.6	2.7	2.6	2.5	2.6	2.6	2.6
			NET	48.5	50.5	52.5	52.5	52.7	53.0	53.4	54.0	54.4	54.9	55.5	56.7	64.5	65.6	66.7
			NET_DG	48.5	50.5	52.5	52.5	52.7	53.0	53.4	54.0	54.4	54.9	55.5	56.7	58.0	59.1	60.1
Newington DS	-	13.5	Load	2.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.2	2.2	2.2	2.2	2.2	2.2
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			CDM	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
			NET	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.2
			NET_DG	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.2
Smiths Falls TS	T3/T4	154.9	Load	92.9	95.8	97.9	98.5	99.0	99.7	100.4	101.1	101.7	102.3	102.9	104.1	105.3	106.4	107.6
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-2.8	-7.9	-11.0	-11.2	-11.2
			CDM	0.5	1.5	2.6	3.3	3.9	4.2	4.4	4.6	4.7	4.8	4.7	4.7	4.5	4.4	4.4
			NET	92.4	94.3	95.3	95.1	95.1	95.5	95.9	96.5	97.0	97.6	100.9	107.2	111.7	113.2	114.4
			NET_DG	92.4	94.3	95.3	95.1	95.1	95.5	95.9	96.5	97.0	97.6	98.3	99.7	101.2	102.4	103.6
St. Lawrence TS	T5/T6	168.1	Load	33.3	33.6	33.9	34.1	34.2	34.4	34.6	34.8	35.0	35.1	35.3	35.6	35.9	36.1	36.4
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-2.9	-8.3	-8.3	-9.7
			CDM	0.2	0.5	0.9	1.2	1.4	1.4	1.5	1.6	1.6	1.6	1.6	1.6	1.7	1.7	1.7
			NET	33.1	33.1	33.0	32.9	32.9	33.0	33.1	33.2	33.4	33.5	33.7	36.8	42.5	42.8	44.4
			NET_DG	33.1	33.1	33.0	32.9	32.9	33.0	33.1	33.2	33.4	33.5	33.7	34.1	34.5	34.8	35.0

Table A.2: St Lawrence Region Summer Non-Coincident Load Forecast

Please note: In the table above NET assumes DG contracts begin to expire and NET_DG assumes DGs remain.

Appendix B: Lists of Step-Down Transformer Stations

Sr. No.	Transformer Stations	Voltages (kV)
1.	Brockville TS (T1/T2)	230/44
2.	Chesterville TS (T1/T2)	115/44
3.	Crosby TS (T1/T2)	230/27.6
4.	Crosby T3	230/44
5.	Morrisburg TS (T3/T4)	115/44
6.	Newington DS	115/27.6
7.	Smith Falls TS (T3/T4)	230/44
8.	St Lawrence TS (T5/T6)	230/44

Appendix C: Lists of Transmission Circuits

Sr. No.	Circuit ID	From Station	To Station	Voltage (kV)
1	L20H, L21H, L22H	St Lawrence TS	Hinchinbrook TS	230k
2	L1MB	St Lawrence TS	Brockville TS	115kV
3	L2M	St Lawrence TS	Brockville TS/ Merivale TS	115kV

Appendix D: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TS	Transformer Station